ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

TABLE OF CONTENTS

ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

(MW)	As at September 30 2017	 December 31 2016
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

<u>Year-To-Date</u>

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(TWh)	**2017**	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.

- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.

- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

<u>Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS</u>

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.

- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.

- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project *(millions of dollars)*	**Capital expenditures** Year-to-date	**Capital expenditures** Life-to-date	**Approved budget**	**Expected in-service date**	**Current status**
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

(millions of dollars) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

	As At	
(millions of dollars) (unaudited)	**September 30 2017**	**December 31 2016**
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	**2018**	**2019**
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		**2016**	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	Expense	2016 Revenue	Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) *(unaudited)*	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) *(unaudited)*	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

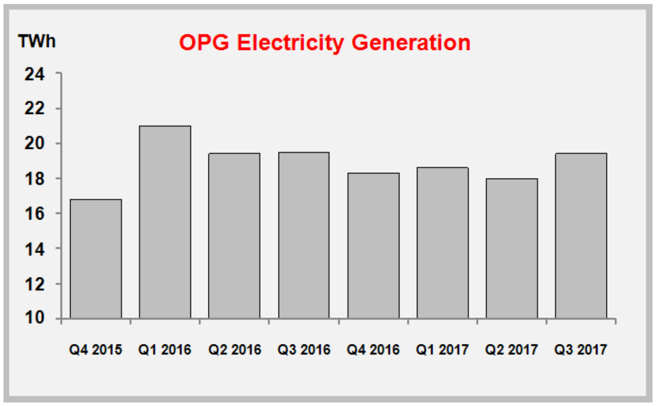
Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

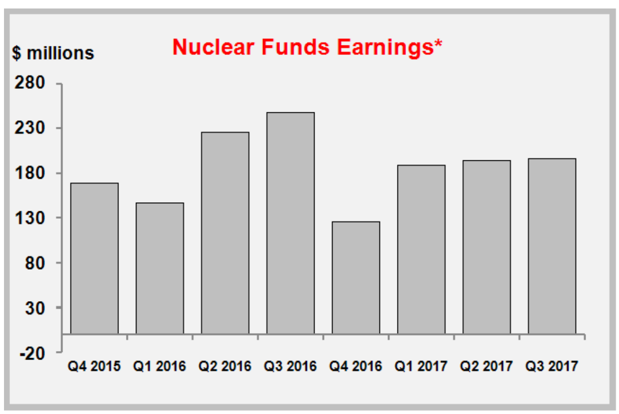
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact:

For further information, please contact:	Investor Relations	416-592-6700
		webmaster@opg.com
	Media Relations	416-592-4008
		1-877-592-4008

www.opg.com
www.sedar.com