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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving a payment amount for hydroelectric generating facilities prescribed under Ontario Regulation 53/05 of the Act, as amended, and the disposition of balances in its deferral and variance accounts as of December 31, 2017.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the Ontario *Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.
2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, (the "Act"), for an order or orders approving a payment amount for hydroelectric generating facilities (the "regulated hydroelectric facilities") prescribed under Ontario Regulation 53/05 of the Act, as amended, ("O. Reg. 53/05") effective January 1, 2019.
3. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB apply the price-cap index methodology for the regulated hydroelectric facilities approved in the EB-2016-0152 Decision and Order dated December 28, 2017 for the period from January 1, 2017 through December 31, 2021 to determine the 2019 payment amount.
4. OPG also seeks an order or orders approving the disposition of the audited balances in all but two of its deferral and variance accounts as of December 31, 2017,¹ and income tax amounts associated with the recovery of the audited balances in the Pension & OPEB

¹ As discussed at Ex. H1-1-1, OPG is not proposing to dispose the balance of the Capacity Refurbishment Variance Account and the Fitness for Duty Deferral Account.

1 Cash Versus Accrual Differential Deferral Account. To recover these amounts, OPG seeks
2 two separate payment riders for the regulated hydroelectric and nuclear generating
3 facilities prescribed under O. Reg. 53/05.

4
5 5. OPG seeks to recover the amounts described in paragraph 4 above, less amounts
6 previously approved for recovery through payment riders established in EB-2016-0152,
7 over a three-year period from January 1, 2019 through December 31, 2021, except for the
8 previously approved balance of the Pension and OPEB Cost Variance Account, the
9 balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and
10 the income tax impacts associated with the recovery of that balance, and the balance of
11 the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub Account. OPG
12 proposes to recover the December 31, 2017 audited balance of the Bruce Lease Net
13 Revenues Variance Account – Non-Derivative Sub Account, the Pension & OPEB Cash
14 Versus Accrual Differential Deferral Account and the income tax impacts associated with
15 the recovery of that balance, over an eight-year period from January 1, 2018 to December
16 31, 2026.² The first three years of that recovery period are reflected in the payment riders
17 proposed in this Application. OPG seeks to recover the previously approved December 31,
18 2017 audited balances in the Pension and OPEB Cost Variance Account, less amounts
19 previously approved for recovery through payments riders established in EB-2016-0152
20 over recovery periods previously authorized by the OEB.³

21
22 6. To disposition the balances in the deferral and variance accounts, and income tax impacts
23 associated with the recovery of the balance in the Pension & OPEB Cash versus Accrual
24 Differential Deferral Account, as described above, OPG is seeking payment riders for the
25 output of the regulated hydroelectric facilities of \$1.65/MWh for the period from January 1,
26 2019 to December 31, 2020, and \$1.56/MWh for the period from January 1, 2021 to

² OPG also makes a proposal for the application of the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account set out in EB-2015-0040 as it relates to the December 31, 2017 balances OPG proposes to recover from the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The details of OPG's proposal are set out in Ex. F1-1-1.

³ Pension and OPEB Cost Variance Account (Future Recovery) is to be recovered by December 31, 2024 (EB-2016-0152 Payment Amounts Order, Appendix G, p. 11); OPG proposes to amortize the remaining balance over 72 months from January 1, 2019 to December 31, 2024). Pension and OPEB Cost Variance Account (Post-2012 Additions) is to be recovered by June 30, 2021 (EB-2016-0152 Payment Amounts Order, Appendix G, p. 11); OPG proposes to amortize the remaining balance over 30 months from January 1, 2019 to June 30, 2021.

1 December 31, 2021; and for the output of the nuclear facilities of \$4.55/MWh for the period
2 from January 1, 2019 to December 31, 2019, \$4.76/MWh for the period from January 1,
3 2020 to December 31, 2020, and \$3.43/MWh for the period from January 1, 2021 to
4 December 31, 2021.

5
6 7. OPG seeks an order declaring the current payment amount interim effective January 1,
7 2019 for the regulated hydroelectric facilities, if the order or orders approving the payment
8 amount are not implemented by January 1, 2019 for the regulated hydroelectric facilities.

9
10 8. The Application will be supported by written evidence. The written evidence filed by OPG
11 may be supplemented or amended from time to time by OPG prior to the OEB's final
12 decision on the Application.

13
14 9. OPG requests that pursuant to section 32.01 of the OEB "Rules of Practice and
15 Procedure", this proceeding be conducted by way of a written hearing.

16
17 10. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB "Rules
18 of Practice and Procedure" for such orders and directions as may be necessary in relation
19 to the Application and the proper conduct of this proceeding.

20
21 11. The persons affected by this Application are all electricity consumers in Ontario. It is
22 impractical to set out the names and addresses of the consumers because they are too
23 numerous.

24
25 12. OPG requests that copies of all documents filed with the OEB by each party to this
26 Application along with copies of all comments filed with the OEB in accordance with Rule
27 9 of the OEB "Rules of Practice and Procedure" be served on the applicant and the
28 applicant's counsel as follows:

1 (a) The applicant: Saba Zadeh
2 Director, Regulatory Affairs
3 Ontario Power Generation Inc.
4

5 Mailing address: HLC
6 700 University Avenue
7 Toronto ON M5G 1X6
8

9 Telephone: 416-592-2976
10

11 Electronic mail: opgregaffairs@opg.com
12
13
14

15 (b) The applicant's Counsel: Charles Keizer
16 Torys LLP
17

18 Mailing address: 79 Wellington St. W.
19 PO Box 270
20 Toronto Dominion Centre
21 Toronto ON M5K 1N2
22

23 Telephone: 416-865-0040
24

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27 Electronic mail: ckeizer@torys.com
28

(c) The applicant's Counsel: Mel Hogg
Assistant General Counsel
Ontario Power Generation Inc.

Mailing address: HLC
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Toronto ON M5G 1X6

Telephone: 416-592-4463

Facsimile: 416-592-1466

Electronic mail: mel.hogg@opg.com

Dated at Toronto, Ontario, this 9th day of August, 2018.

Ontario Power Generation Inc.

[Original signed by]

Charles Keizer

Torys LLP

APPROVALS

In this Application, OPG is seeking the following specific approvals:

1. Approval and implementation of the 2019 Hydroelectric Payment Amount effective January 1, 2019, determined pursuant to the price-cap index mechanism approved by the OEB in EB-2016-0152.
2. Approval to clear the approved balances as of December 31, 2017 in the following accounts, less amounts previously approved for recovery through payment riders established in EB-2016-0152: ¹
 - Hydroelectric Water Conditions Variance Account
 - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
 - Hydroelectric Surplus Baseload Generation Variance Account
 - Income and Other Taxes Variance Account
 - Pension and OPEB Cost Variance Account – Future Recovery and Post-2012 Additions components
 - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
 - Pension & OPEB Cash Payment Variance Account
 - Pension & OPEB Cash Versus Accrual Differential Deferral Account
 - Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
 - Nuclear Liability Deferral Account
 - Nuclear Development Variance Account
 - Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
 - Nuclear Deferral and Variance Over/Under Recovery Variance Account
 - Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account

¹ Accounts with a zero balance are not listed.

1 ○ SR&ED ITC Variance Account

- 2
- 3 3. Approval to recover the income tax impacts associated with the approved recovery of the
- 4 Pension & OPEB Cash Versus Accrual Differential Deferral Account balances requested
- 5 above.
- 6
- 7 4. Except for (i) the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and
- 8 income tax impacts associated with recovery of those balances, (ii) the Pension and OPEB
- 9 Cost Variance Account (Future Recovery), (iii) the Pension and OPEB Cost Variance
- 10 Account (Post 2012 Additions), and (iv) the Bruce Lease Net Revenues Variance Account
- 11 – Non-Derivative Sub-Account, approval to clear the approved balances in the accounts
- 12 listed in paragraph two over a 3-year period from January 1, 2019 to December 31, 2021.
- 13
- 14 5. Approval to clear the approved balances in the Pension & OPEB Cash Versus Accrual
- 15 Differential Deferral Account, and income tax impacts associated with recovery of those
- 16 balances, and the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-
- 17 Account over an 8-year period from January 1, 2019 to December 31, 2026.
- 18
- 19 6. Approval to clear the previously approved balance in the Pension and OPEB Cost Variance
- 20 Account (Future Recovery) over a 6-year period from January 1, 2019 to December 31,
- 21 2024.
- 22
- 23 7. Approval to clear the previously approved balance in the Pension and OPEB Cost Variance
- 24 Account (Post 2012 Additions) over a 2.5 year period from January 1, 2019 to June 30,
- 25 2021.
- 26
- 27 8. A finding on the application of the Pension & OPEB Forecast Accrual versus Actual Cash
- 28 Payment Differential Variance Account established in EB-2015-0040 to amounts proposed
- 29 to be recovered by OPG from the Pension & OPEB Cash Versus Accrual Differential
- 30 Deferral Account established in EB-2013-0321, as set out in Ex. F1-1-1.
- 31

1 9. Approval of the following payment riders to recover the applicable portion of the approved
2 balances in the accounts listed above: for the regulated hydroelectric facilities of
3 \$1.65/MWh for the period from January 1, 2019 to December 31, 2020, and \$1.56/MWh
4 for the period from January 1, 2021 to December 31, 2021; and for the nuclear facilities of
5 \$4.55/MWh for the period from January 1, 2019 to December 31, 2019, \$4.76/MWh for the
6 period from January 1, 2020 to December 31, 2020, and \$3.43/MWh for the period from
7 January 1, 2021 to December 31, 2021.

8
9 10. An order from the OEB declaring OPG's current payment amount for regulated
10 hydroelectric facilities interim as of January 1, 2019, if the order or orders approving the
11 payment amount are not implemented by January 1, 2019.

DRAFT ISSUES LIST

The following is the draft issues list proposed by OPG.

1. Are the amounts recorded in the applicable deferral and variance accounts appropriate?
2. Are the balances for recovery in each of the deferral and variance accounts appropriate?
3. Are the proposed rate riders and disposition periods for the account balances appropriate?
4. Does OPG's proposed treatment of pension and OPEB costs appropriately reflect the OEB's Decision in EB-2013-0321 and OEB policy as set out in the Report of the OEB: *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*, issued in the generic proceeding EB-2015-0040?
5. Has OPG accurately applied the OEB-approved price-cap adjustment formula in its 2019 hydroelectric rate adjustment proposal?

STAKEHOLDER INFORMATION SESSION

1.0 PURPOSE

This evidence provides a description of the stakeholder information session that OPG held on the Application prior to filing it with the OEB.

2.0 BACKGROUND

OPG held a stakeholder information session on August 7, 2018, in advance of submitting the Application. The following provides an outline of the session including the objective, process, participants, and participant funding guidelines.

3.0 OBJECTIVE

The objective of the information session was to inform stakeholders about the Application.

4.0 PROCESS

OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's payment amounts (EB-2016-0152) and deferral and variance account balance disposition (EB-2014-0370).

The stakeholder invitation letter, including funding guidelines, is provided in Attachment 1. Funding was offered to participants who qualified under the funding guidelines. The session agenda and presentation provided to stakeholders related to the Application are provided in Attachments 2 and 3, respectively.

LIST OF ATTACHMENTS

- 1
- 2
- 3 Attachment 1: Stakeholder Invitation Letter and
- 4 Funding Guidelines
- 5
- 6 Attachment 2: Session Agenda
- 7
- 8 Attachment 3: Presentation

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-2976 Fax: 416-592-8519
saba.zadeh@opg.com

July 23, 2018

VIA EMAIL

Dear Stakeholder:

**Stakeholder Information Session:
Application for 2019 Hydroelectric Payment Amount Application and D&V
Account Clearance**

OPG is currently preparing an application to the OEB for the annual formulaic adjustment to its 2019 hydroelectric payment amount and disposition of the balances in its Deferral and Variance accounts as at December 31, 2017, effective January 1, 2019 (the "Application"). OPG plans to file the Application by mid August 2018. The purpose of this letter is to invite you to participate in a stakeholder information session that OPG is going to conduct in advance of filing the Application.

The objective of this information session is to provide an overview of the planned Application.

We are contacting stakeholders who we believe will have an interest in the Application. The half-day information session will be held on August 7, 2018, from 1:30 pm – 3:00 pm in the Mini-Auditorium, mezzanine level at OPG's head office, 700 University Avenue (corner of University Ave. and College St.) in Toronto.

The agenda for the day will be forwarded to participants in advance of the session. All presentation materials will be posted on OPG's web-site, www.opg.com following the session.

OPG will provide funding for participation in the stakeholder process to eligible participants. A copy of the funding guidelines is attached for your information.

If you have any questions or would like to discuss OPG's stakeholder process or the upcoming application, please contact me at 416-592-2976 or by email at opgregaffairs@opg.com. Please confirm your attendance at the session by

contacting Lucy D'Avella by email at lucy.davella@opg.com or by phone at 416-592-3596.

Best Regards,

A handwritten signature in black ink, appearing to read 'Saba Zadeh', with a long horizontal stroke extending to the left.

Saba Zadeh
Case Manager
Director, Ontario Regulatory Affairs

Attachment:

1. OPG Stakeholder Information Session Participant Funding Guideline

Attachment 1

Participant Funding Guidelines

To facilitate dialogue with its stakeholders, Ontario Power Generation (OPG) will provide funding to assist qualifying stakeholders to participate in its stakeholder consultation process related to its application to the Ontario Energy Board (OEB) for payment amounts for regulated facilities. The funding criteria that will be used are based on the OEB's most recent Practice Direction on Cost Awards. The following provides eligibility guidelines and a description of the funding process.

Eligibility

- The determination of whether a party is eligible for funding will be at the sole discretion of OPG.
- Funding is limited to not-for-profit organizations whose interests are affected by the application such as public interest organizations, environmental organizations, and Aboriginal communities.
- Individuals and organizations with a direct commercial or business interest in the application are not eligible for funding. This includes, but may not be limited to, transmitters, wholesalers, generators, distributors, retailers and marketers, or organizations representing these interests.
- Municipal or provincial government staff or representatives are not eligible for funding.
- Parties with similar interests are encouraged to combine their participation.
- Funding will be provided only to stakeholders participating in the discussion session.

Process for Funding and Eligible expenses

- To allow timely processing of requests, it is suggested that stakeholders seeking funding apply to OPG at least 7 days prior to the session. Stakeholders should indicate in writing that they will be participating and include a statement justifying their eligibility. Parties should submit their written request for financial support to:

Ms. Saba Zadeh, Case Manager
Ontario Power Generation
700 University Ave. H18-G3,
Toronto, ON M5G 1X6
Phone: 416-592-2976
Email: opgregaffairs@opg.com

OPG will notify the party prior to the session if their funding application is accepted.

- Funding will be provided for meeting preparation and attendance for one person based on rates outlined in the OEB's Cost Award Tariff.
- Preparation time is not to exceed an amount equal to the meeting time. Preparation time is only allowed if the stakeholder attends the session.

- Out of pocket travel expenses will be allowed including reasonable meals and accommodation only if the participant's place of business is greater than 100 km from the meeting site. Receipts must be submitted for all meals, accommodations and travel with the exception of mileage for personal automobile.
- Reasonable disbursements, such as postage, photocopying, etc., are eligible expenses.
- Eligible participants must submit an OPG disbursement claim sheet form complete with receipts, no later than 30 days after the session.

AGENDA

OPG Information Session August 7, 2018

Mini Auditorium – 700 University Avenue, Toronto, ON
Mezzanine Level

1:30 p.m. – 1:45 p.m.	- Registration
1:45 p.m. – 2:00 p.m.	- Welcome - Introductions - Safety Rules
2:00 p.m. – 2:40 p.m.	- Overview
2:40 p.m. – 3:00 p.m.	- Q & A

For those who can't attend the session, you can participate via Skype:

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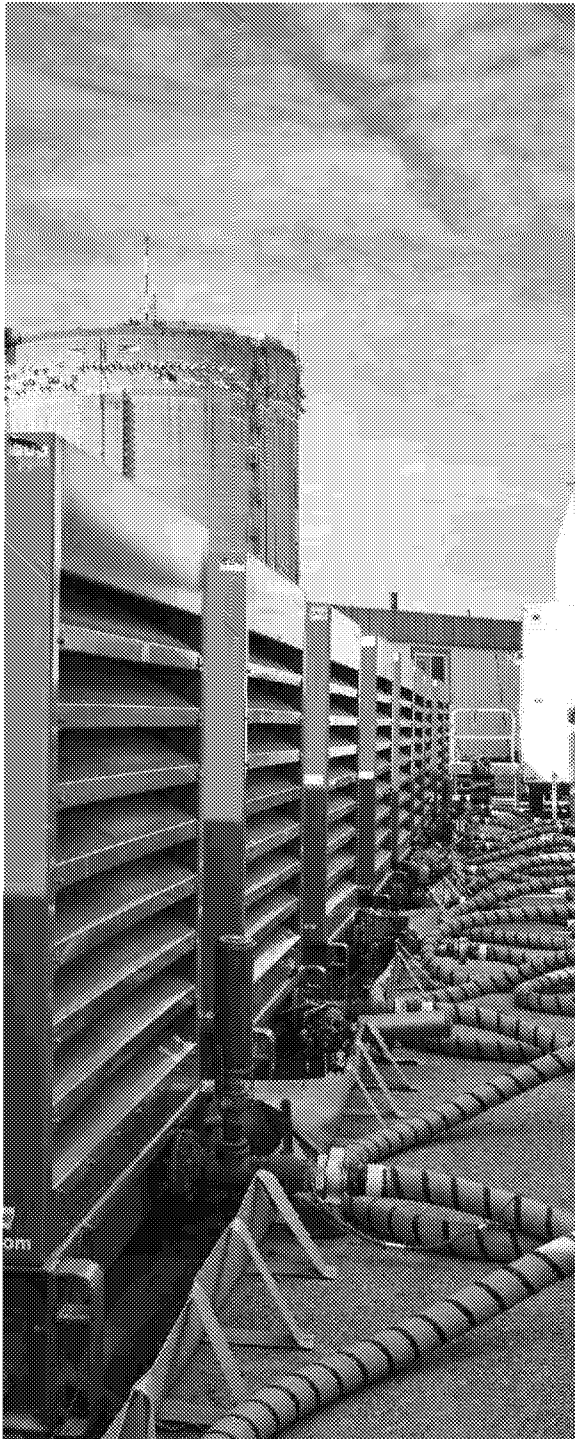
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ONTARIO
GENERATION

Annual Hydroelectric Rate Adjustment and Deferral & Variance Account Recovery

Stakeholder Information Session

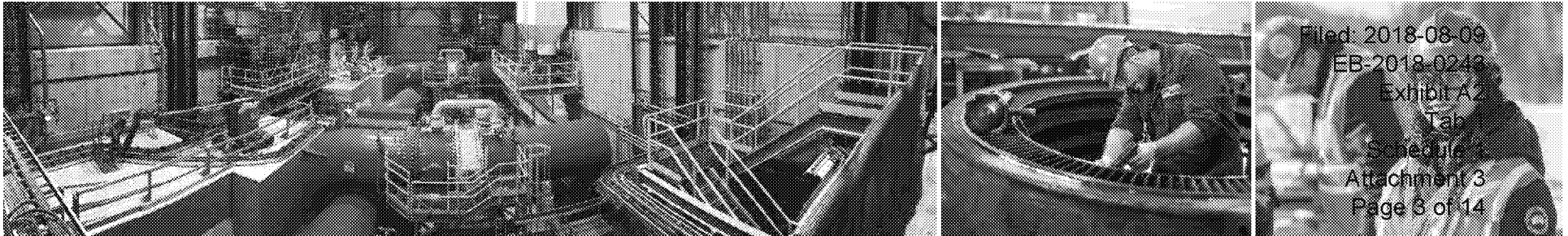
August 7, 2018



Agenda:

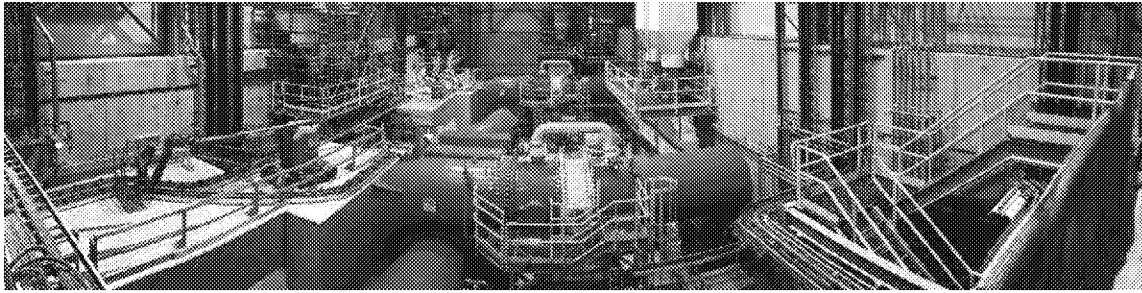
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Note: Information presented in this information session is subject to change in the final application.



Application Summary and Timing

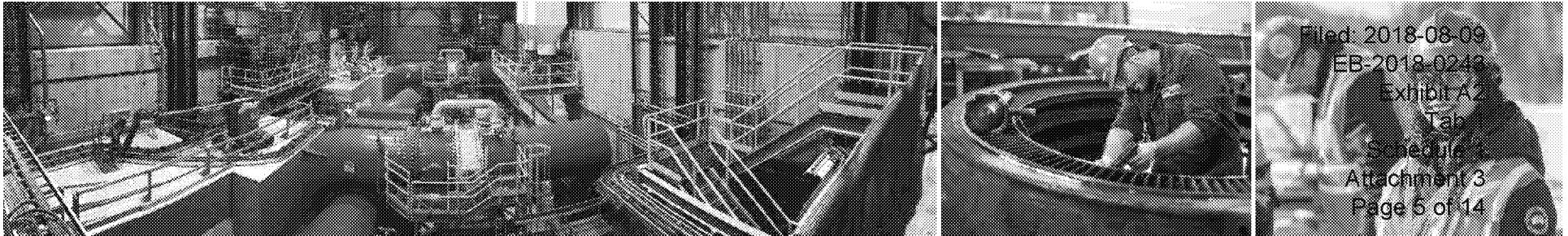
- In its Decision and Order in EB-2016-0152, the OEB provided that OPG may file for clearance of its D&V account balances, including the Pension & OPEB Cash Versus Accrual Differential Deferral Account, at the same time as its 2019 hydroelectric payment amounts application



Application Summary

- 2019 Hydroelectric Payment Amount effective January 1, 2019, determined using the price-cap index mechanism approved by the OEB in EB-2016-0152
- Clearance of D&V account balances, as at December 31, 2017, less amounts previously approved for recovery through payment riders established in EB-2016-0152:
 - including the Pension & OPEB Cash Versus Accrual Differential Deferral Account (“Interim Account”) and recovery of associated tax amounts
- A finding on applying the Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account established in EB-2015-0040 to amounts proposed to be recovered by OPG from the Interim Account as part of this application
- Request that proceeding be conducted by way of written hearing

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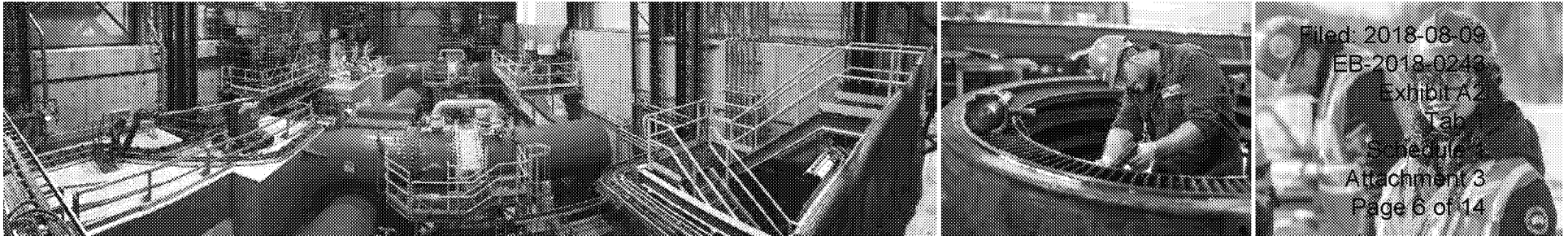
Annual Hydroelectric Adjustment

- Approval of 2019 Hydroelectric Payment Amount (“HPA”), effective January 1, 2019
- As set out in EB-2016-0152 (PAO, p. 9, para 3), the HPA for each year is determined using the price-cap index approved by the OEB for OPG as part of that application:

$$\text{Payment Amount}(t) = \text{Payment Amount}(t-1) \times \left(1 + \frac{\text{Inflation Factor}}{\text{Factor}} - \left(\frac{\text{Productivity Factor}}{\text{Factor}} + \frac{\text{Stretch Factor}}{\text{Factor}} \right) \right)$$

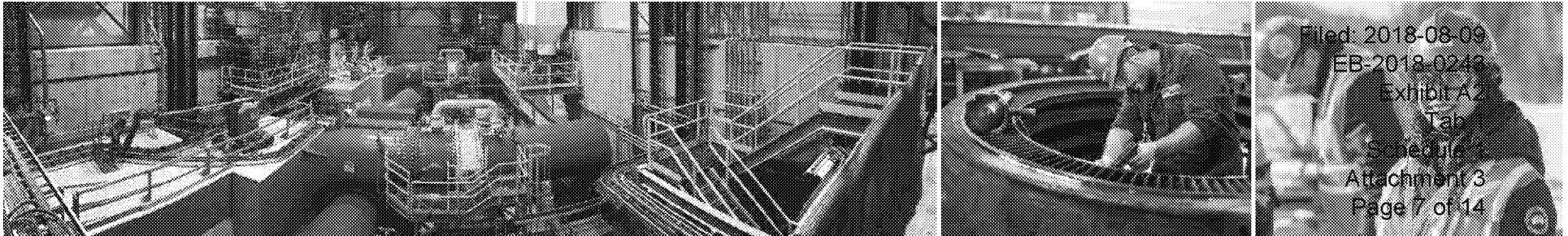
- 2016 OEB-published and 2017 Statistic Canada index values used as proxy to determine inflation factor (approx. 1.5%)
- OPG will update application with OEB-published index values, expected fall 2018
- OPG estimates the 2019 HPA to be \$42.55/MWh

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Deferral and Variance Accounts

- OPG proposes to recover December 31, 2017 D&V account balances for all accounts (less amounts previously approved for recovery through payment riders established in EB-2016-0152), with the exception of the following accounts:
 1. Capacity Refurbishment Variance Account, and
 2. Fitness for Duty Deferral Account
- OPG proposes to defer recovery of balances in these two accounts to a future application



Proposed Recovery Periods

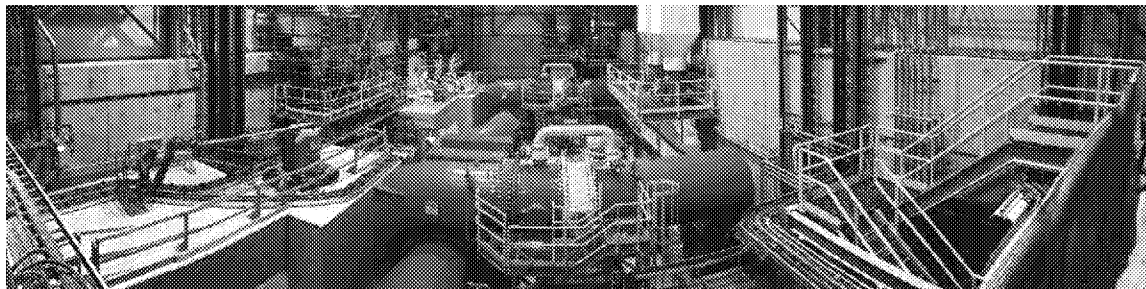
- OPG proposes to clear the recoverable amounts over a 3-year period from January 1, 2019 to December 31, 2021 with the exception of:
 1. the Interim Account, including associated tax impacts, and the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account over an 8-year period from January 1, 2019 to December 31, 2026
 2. the Pension and OPEB Cost Variance Account (Future Recovery) over a 6-year period from January 1, 2019 to December 31, 2024, and
 3. the Pension and OPEB Cost Variance Account (Post 2012 Additions) over a 2.5 year period from January 1, 2019 to June 30, 2021
- The recovery periods in (2) and (3) above were previously approved by the OEB.



Proposed D&V Recovery - Hydroelectric

Account	2017 Audited Balances	EB-2016-0152 Amortization	Remaining Balance
Hydroelectric Water Conditions Variance	(150.2)	(17.3)	(132.9)
Ancillary Services Net Revenue Variance - Hydroelectric	(45.0)	(13.2)	(31.8)
Hydroelectric Incentive Mechanism Variance	(0.1)	(0.1)	0
Hydroelectric Surplus Baseload Generation Variance	360.4	82.5	278
Income and Other Taxes Variance - Hydroelectric	0	0	0
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	5.7	0	5.7
Pension and OPEB Cost Variance - Hydroelectric - Future	8.4	2.1	6.3
Pension and OPEB Cost Variance - Hydroelectric	26.6	11.8	14.8
Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric	83.2	0.0	83.2
Pension & OPEB Cash Payment Variance - Hydroelectric	(25.9)	4.3	(30.1)
Hydroelectric Deferral and Variance Over/Under Recovery Variance	25.7	13.5	12.2
Total Deferral and Variance Account Amounts	288.8	83.6	205.4
Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric			27.7
Total Recoverable Amounts			233.1

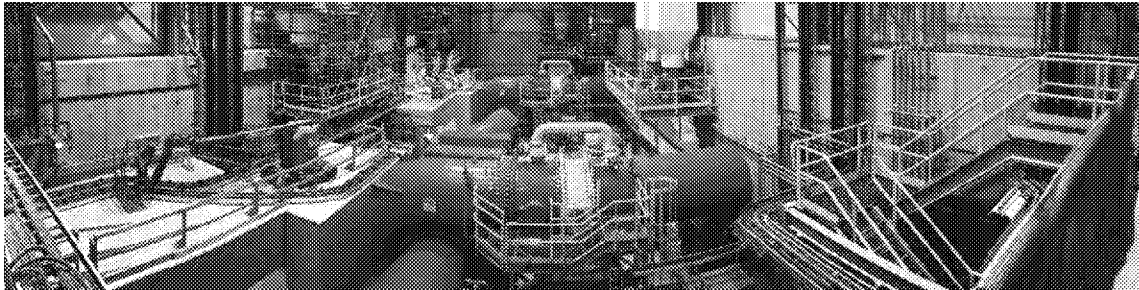
Table subject to finalization



Proposed D&V Recovery – Nuclear

Account	2017 Audited Balances	EB-2016-0152 Amortization	Remaining Balance
Nuclear Liability Deferral	18.6	0.0	18.6
Impact Resulting from Changes in Station End-of-Life Dates (Dec 31, 2015)	(103.4)	0.0	(103.4)
Nuclear Development Variance	1.9	1.7	0.2
Ancillary Services Net Revenue Variance - Nuclear	3.4	1.0	2.4
Bruce Lease Net Revenues Variance - Derivative Sub-Account	(69.4)	(68.6)	(0.8)
Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	189.2	20.6	168.7
Income and Other Taxes Variance - Nuclear	(10.1)	(4.3)	(5.8)
Pension and OPEB Cost Variance - Nuclear - Future	171.7	42.9	128.8
Pension and OPEB Cost Variance - Nuclear	508.9	226.2	282.7
Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear	530.5	0.0	530.5
Pension & OPEB Cash Payment Variance - Nuclear	(114.0)	23.4	(137.4)
Nuclear Deferral and Variance Over/Under Recovery Variance	74.7	44.1	30.6
SR&ED ITC Variance	(3.4)	0.0	(3.4)
Total Deferral and Variance Account Amounts	1,198.6	287.0	911.6
Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear			176.8
Total Recoverable Amounts			1,088.5

Table subject to finalization



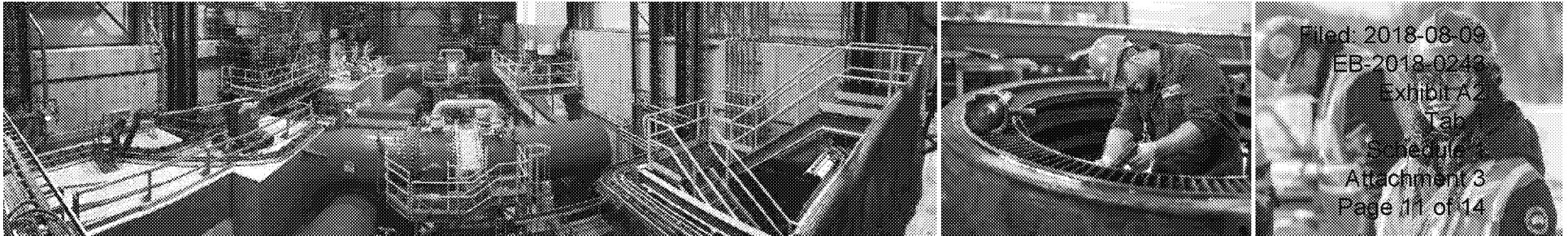
Current and Proposed Payment Amounts and Riders

	2018	2019	2020	2021
Description				
Hydroelectric Payment Amount (\$/MWh)	42.05	42.55	43.07	43.58
Hydroelectric Payment Rider A (\$/MWh)	0.52	1.44	1.01	0.00
Hydroelectric Payment Rider B (\$/MWh) (Hydroelectric Interim Period Shortfall Recovery Rider)	0.13	0.35	0.24	0.00
Hydroelectric Payment Rider C (\$/MWh)	0.00	1.65	1.65	1.56
Nuclear Payment Amount (NPA) (\$/MWh)	78.64	77.00	85.00	89.70
Nuclear Payment Rider A (NPR) (\$/MWh)	1.05	2.79	2.04	0.00
Nuclear Payment Rider B (\$/MWh) (Nuclear Interim Period Shortfall Recovery Rider)	2.88	7.71	5.64	0.00
Nuclear Payment Rider C (\$/MWh)	0.00	4.56	4.76	3.43

Table subject to finalization

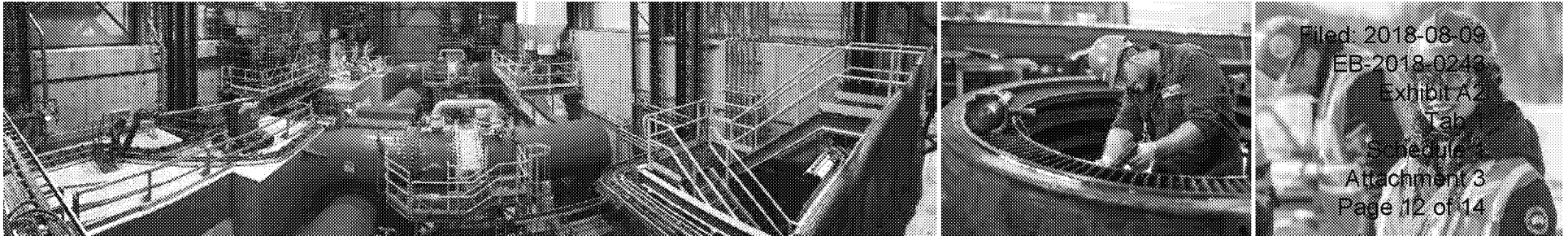
- The average incremental impact of the proposed payment riders and 2019 HPA is about \$0.40 (or less than 0.4%) per year on the typical residential customer monthly bill during the 2019 to 2021 period

ONTARIOPOWER
GENERATION



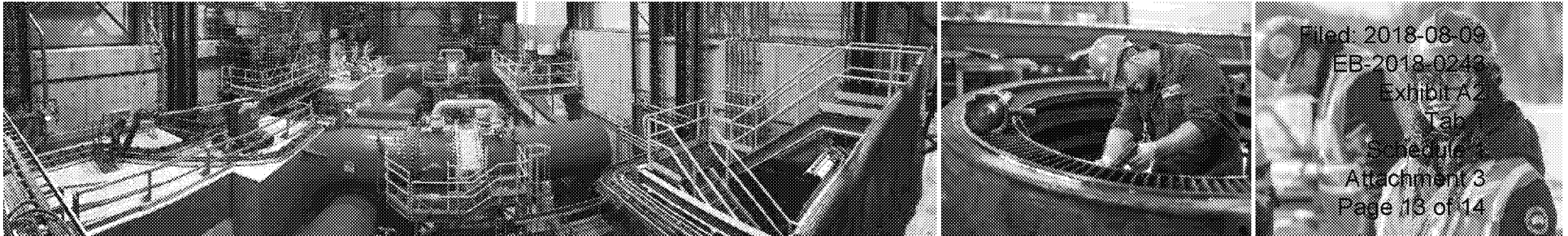
Creation of Interim Account

- In EB-2013-0321, OPG proposed to recover its pension and OPEB costs for 2014 and 2015 based on the accrual method of accounting, consistent with the rate-setting methods in prior OEB decisions on OPG's payment amounts
- In the absence of an OEB ratemaking policy on this issue at that time, the OEB:
 1. limited the amount of pension and OPEB costs in payments amounts to cash amounts on a temporary basis, and
 2. established the Interim Account to record cash to accrual differences
- (1) and (2) were established, and continued in EB-2016-0152, contingent on the outcome of the OEB's generic consultation to decide on the appropriate ratemaking treatment of these costs for all regulated utilities



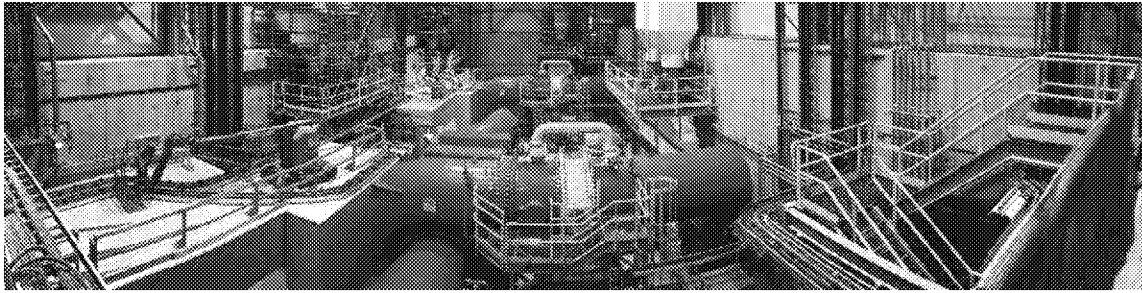
Outcome of Generic Consultation

- In September 2017, the OEB issued a report on *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs* (the “Report”) from its generic consultation, EB-2015-0040
- The Report established:
 1. the OEB’s policy on methodology to account for P/OPEB costs when setting rates, and
 2. the Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account



Implementation of Outcome in Application

- OPG seeks approval to recover the audited balance of the Interim Account as of December 31, 2017
- OPG will continue to record amounts in the Interim Account until the effective date of OPG's next cost-based payment amounts order
- OPG proposes that recoveries of amounts recorded in the Interim Account as of December 31, 2017 would not be captured in the new differential variance account and therefore not be subject to carrying charges



Filed: 2018-08-09
EB-2018-0243
Exhibit A2
Tab 1
Schedule 3
Attachment 3
Page 14 of 14

Questions?

RECOVERY OF PENSION AND OPEB ACCRUAL COSTS

1.0 PURPOSE

This schedule sets out OPG's proposal to recover amounts related to the company's pension and other post-employment benefits ("OPEB") costs recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account established by the OEB in EB-2013-0321 and most recently continued in EB-2016-0152 (the "Interim Account").

OPG's proposal implements the OEB's policy on pension and OPEB cost recovery set out in the OEB's Report: *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs* (the "Report"), issued in the OEB's generic consultation on the issue (EB-2015-0040). OPG proposes to recover the audited balances of the Interim Account as of December 31, 2017, which total approximately \$614M, and associated income tax impacts.

This schedule also sets out OPG's proposal for the application of the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account ("New Differential Account") set out in the Report, as it relates to amounts proposed for recovery from the Interim Account.

2.0 OVERVIEW

The substance of this schedule is divided into three sections:

- Section 3.0 summarizes the OEB policy applicable to OPG's proposal to recover the audited balances in the Interim Account, as determined in two prior OPG payment amount proceedings and in the Report.
- Section 4.0 sets out OPG's proposed implementation of the OEB's policy on pension and OPEB cost recovery as determined in the Report, including as it relates to the recovery of the Interim Account balances.
- Section 5.0 sets out OPG's proposal for the application of the New Differential Account to the amounts recorded in the Interim Account prior as of December 31, 2017.

3.0 OEB POLICY ON PENSION AND OPEB COST RECOVERY

This section summarizes the OEB findings that established the Interim Account, determined the OEB policy on the regulatory treatment of pension and OPEB costs, and authorized OPG to seek recovery of the audited balances of the Interim Account in this application. Collectively, these prior findings determine the scope of the issue before the OEB in this proceeding as related to the Interim Account. The sub-sections below summarize the relevant elements of the prior OPG payment amount decisions and the Report.

3.1 ESTABLISHING THE INTERIM ACCOUNT

In EB-2013-0321, OPG proposed to recover its pension and OPEB costs for 2014 and 2015 based on the accrual method of accounting. Accrual accounting is used almost exclusively by regulated utilities in Ontario as the basis to recover pension and OPEB costs.¹ As addressed in the EB-2013-0321 proceeding, accrual accounting is also required by generally accepted financial accounting standards, including USGAAP, to measure and record pension and OPEB costs, and is consistent with the rate-setting methods in prior OEB decisions on OPG's payment amounts.

In the absence of an OEB ratemaking policy as it relates to pension and OPEB costs at the time of EB-2013-0321, the OEB determined that it would limit the amount of pension and OPEB costs included in OPG's 2014 and 2015 payment amounts to OPG's cash requirements for the period, being OPG's contributions to its registered pension plan and OPEB cash payments.² The OEB also established the Interim Account, effective November 1, 2014, to record the difference between OPG's actual pension and OPEB costs determined using the accrual accounting method applied in OPG's consolidated financial statements and OPG's actual "cash" pension plan contributions and OPEB payments for the prescribed facilities, pending the outcome of a generic proceeding on the regulatory treatment of pension and OPEB costs.^{3,4} In establishing

¹ The exceptional instances in which utilities use methods other than accrual accounting to recover such costs were reviewed in the EB-2015-0040 generic consultation, as summarized in section 3.2 below.

² EB-2013-0321, Decision with Reasons, dated November 20, 2014 ("EB-2013-0321 Decision"), pp. 88-89.

³ EB-2013-0321 Decision, pp. 88-89.

⁴ The EB-2013-0321 Decision also established the Pension & OPEB Cash Payment Variance Account to record the difference between OPG's actual pension plan contributions and actual OPEB payments for the prescribed

1 the Interim Account, the OEB stated that “[a]ny future treatment regarding the deferral account
2 would be limited to the outcomes of the generic proceeding as they relate to the accounting or
3 mechanics of recovery, as applicable.”⁵

4
5 The OEB set OPG’s payment amounts based on the “cash” method as a temporary measure,
6 contingent on the outcome of the generic proceeding. The OEB stated that it was “not
7 necessarily permanently moving from an accrual to a cash basis for setting OPG’s payment
8 amounts.”⁶ It also found that “[t]ransition to a different accounting treatment of pensions and
9 OPEBs for OPG, if required, would be addressed by the Board in OPG’s next cost of service
10 proceeding, having been informed by the outcomes of the generic proceeding.”⁷

11
12 By setting payment amounts using the cash amounts and establishing the Interim Account to
13 record the difference between the cash and accrual accounting methods, the OEB effectively
14 deferred a final determination on the rate treatment of OPG’s pension and OPEB costs. The
15 deferral of amounts in the Interim Account allowed the OEB to keep the company whole if the
16 generic proceeding determined that the accrual accounting method is appropriate.⁸

17
18 The Interim Account does not include the income tax impacts associated with the difference
19 between recovery of the cash amounts and accrual accounting costs.⁹ Parties raised the
20 treatment of income tax impacts in submissions on the EB-2013-0321 Draft Payment Amounts

facilities and such forecast amounts included in the payment amounts. This variance account was most recently continued in EB-2016-0152.

⁵ EB-2013-0321 Decision, p. 89. As the OEB had already found that OPG’s underlying pension and OPEB costs were prudent, it excluded any further prudence review of the amounts recorded in the Interim Account.

⁶ EB-2013-0321 Decision, p. 88.

⁷ *Ibid.*

⁸ For example, the Report (p. 11) notes that “[v]ariance accounts were used to capture the difference between the cash and accrual methods in order to keep the period open for final adjustments once the outcome of the consultation was known.”

⁹ As discussed in EB-2016-0152 (Ex. F4-2-1, section 3.2.5) and EB-2013-0321 (Ex. F4-2-1, section 3.3.5) and as reflected in the regulatory income taxes approved in previous OPG payment amounts proceedings that used the accrual accounting method of recovery, pension and OPEB accrual costs are not deductible for income tax purposes under the *Income Tax Act* (Canada), while the cash amounts are deductible. Therefore, OPG will incur incremental income taxes as a result of recovering the accrual accounting costs for pension and OPEB, to the extent these costs are higher than the cash amounts, as there is no incremental income tax benefit (i.e., deduction) available to be passed on to ratepayers in connection with the inclusion of the accrual costs. Since income taxes are based on the revenue that a utility receives through rates, OPG will be subject to these incremental income taxes as it recovers the Interim Account balances.

1 Order.¹⁰ At that time, the OEB did not determine the mechanism by which the income tax
2 impacts related to the Interim Account would be recovered. Instead, it deferred the issue until
3 “a determination is made regarding the account balance, [at which time] any tax matters can be
4 addressed.”¹¹

6 **3.2 THE GENERIC CONSULTATION AND NEW OEB POLICY**

7 Following the EB-2013-0321 proceeding, the OEB conducted a generic consultation process
8 (EB-2015-0040) on the regulatory treatment of pension and OPEB costs in rates for all Ontario
9 rate-regulated utilities. As part of the consultation, the OEB solicited several rounds of
10 submissions from utilities and stakeholders and issued the Report on September 14, 2017.

11
12 The generic consultation confirmed that the majority of utilities use the accrual accounting
13 method to recover pension and OPEB costs.¹² The few exceptions include utilities using cash
14 payments to plan beneficiaries (i.e. “pay-as-you-go” amounts) as the basis for recovery of non-
15 registered pension plan and OPEB amounts,¹³ and one utility using the funding method to
16 recover its registered pension plan costs.¹⁴

17
18 The Report established the OEB’s policy that the accrual method is presumptively appropriate
19 for setting rates to recover pension and OPEB costs. The Report states that “[t]he OEB will use
20 the pension and OPEB amounts determined through accrual accounting in rate-setting, unless
21 that method does not result in just and reasonable rates.”¹⁵

¹⁰ OPG noted that the OEB had consistently included income tax impacts in pension and OPEB-related accounts for OPG in previous proceedings (EB-2013-0321, OPG Response to Intervenor Comments on the Draft Payment Amounts Order, dated December 12, 2014, p. 7).

¹¹ EB-2013-0321 Payment Amounts Order, p. 6.

¹² EB-2015-0040, KPMG Presentation on P & OPEB Costs – Alternatives Identified, dated July 19-20, 2016, p. 3.

¹³ The Report (p. 7) notes that some utilities who do not incur material amounts for OPEB costs may not conduct actuarial valuations for accounting purposes, and therefore the OPEB expense reported on their financial statements may be equivalent to the pay-as-you-go amount.

¹⁴ Hydro One Networks Inc. uses the funding method whereby employer contributions to the pension plan are recovered through rates. (EB-2015-0040, KPMG Presentation on P & OPEB Costs – Alternatives Identified, dated July 19-20, 2016, p.3.) For electricity distributors in Ontario who are members of the OMERS pension plan, the employer contributions made to the plan are equal to the accrual accounting cost (The Report, p. 6).

¹⁵ The Report, p. 8.

1 The Report observes that “as [the] setting [of] just and reasonable rates is the primary driver of
2 the regulatory treatment of pension and OPEB costs, providing value to customers and assuring
3 fairness to both present and future ratepayers is a necessary component of the regulatory
4 treatment of pension and OPEB costs.”¹⁶ Consistent with these principles, the Report
5 established the New Differential Account to track the difference between the amounts in
6 recovered rates (on an accrual basis) and the actual cash payments made by utilities (employer
7 contributions to the pension plan and expenditures paid out to OPEB plan beneficiaries) for all
8 utilities recovering pension and OPEB amounts on an accrual basis, effective January 1, 2018.¹⁷
9 This account is used to calculate a carrying charge to be credited to customers on the
10 cumulative cash-to-accrual difference.¹⁸ Only the carrying charges applied to the account are
11 subject to disposition.¹⁹

12
13 The Report also clarifies the evidentiary requirements for utilities proposing to remain on an
14 accrual basis, and for those proposing to set rates using a method other than accrual. The OEB
15 determined that utilities in the former group have no special evidentiary burden; utilities currently
16 using the accrual method and proposing to continue using the that method “are not required to
17 justify the use of that method, but must still file the evidence required by the OEB to support the
18 quantum.”²⁰

19
20 In contrast, the Report puts a greater evidentiary burden on utilities that propose to set rates
21 using a method other than accrual. Such utilities are required to “support such a proposal with
22 evidence giving consideration to these factors, and the principles and practices enunciated in
23 [the] Report.”²¹

24 25 **3.3 OEB APPROVAL TO SEEK RECOVERY IN THIS APPLICATION**

¹⁶ *Ibid.*

¹⁷ *Ibid.*, p. 11.

¹⁸ The Report (p. 10) allows compensation to a utility for cash payments that exceed accrual cost recoveries in circumstances where the financial viability of the utility would be compromised.

¹⁹ The Report (p. 11) provides that this disposition should occur during a utility's cost-based rate application, unless otherwise approved by the OEB.

²⁰ The Report, p. 8 (emphasis added).

²¹ *Ibid.*

1 In the EB-2016-0152 proceeding to set OPG's payment amounts for 2017 to 2021, OPG
2 proposed that it would be appropriate for the company to seek recovery of the balances in the
3 Interim Account, in its first annual hydroelectric payment amount application. OPG noted, as it
4 did in its submissions in the generic consultation that continued recognition of amounts recorded
5 in the Interim Account as a regulatory asset in OPG's financial statements prepared in
6 accordance with USGAAP requires that the period of deferring amounts recorded in the Interim
7 Account must not exceed five years from the time that they were incurred.²² As a result, OPG
8 must begin to recover amounts recorded to the Interim Account no later than November 2019,
9 or otherwise be required to write-off the regulatory asset for the affected amounts against net
10 income.²³

11
12 The OEB determined that OPG may seek to recover audited deferral and variance account
13 balances at the same time as its 2019 hydroelectric payment amounts application, including a
14 proposal for the Interim Account and the regulatory accounting method for pension and OPEB
15 costs to be used going forward.²⁴

17 **4.0 PROPOSED IMPLEMENTATION OF OEB POLICY**

18 OPG seeks approval to recover the audited balances of the Interim Account as of December 31,
19 2017 and the income tax impacts associated with recovery of those balances. As set out in Ex.
20 H1-1-1,²⁵ OPG proposes that the applicable portion of those amounts be included in the
21 requested 2019-2021 deferral and variance account payment riders. Evidence supporting the
22 quantum recorded in the Interim Account is set out in Ex. H1-1-1. The income tax impacts
23 associated with recovery of the December 31, 2017 Interim Account balances are calculated to
24 be approximately \$205M over the full recovery period.²⁶ The payment riders proposed for the
25 period from January 1, 2019 to December 31, 2021 would recover the income tax impacts that

²² EB-2016-0152, OPG Reply Argument, p. 214.

²³ *Ibid.*

²⁴ EB-2016-0152, Decision and Order, dated December 28, 2017, p. 119 and p. 160 ("EB-2016-0152 Decision").

²⁵ Ex. H1-2-1: Table 1, lines 10 and 14 (regulated hydroelectric) and Table 2, lines 13 and 20 (nuclear).

²⁶ Ex. H1-2-1: Table 1, line 14 (hydroelectric), and Table 2, line 20 (nuclear). Using the income tax rate of 25%, the total income tax impact is calculated pursuant to the following gross-up formula: $\$614\text{M} * \text{tax rate} / (1 - \text{tax rate}) = \$614\text{M} * 0.25 / 0.75 = \$204.7\text{M}$.

1 OPG will incur due to the Interim Account recoveries in that period, which are calculated to be
2 approximately \$77M.²⁷

3
4 As detailed in Ex. H1-2-1, OPG is proposing to mitigate customer bill impacts by recovering the
5 December 31, 2017 Interim Account balances and associated income tax impacts over an eight-
6 year period beginning on January 1, 2019.

7
8 Recovering the Interim Account balance and associated income tax impacts would reconcile
9 the interim reductions to OPG's payment amounts made in the EB-2013-0321 Decision (and
10 continued in the EB-2016-0152 Decision) with the OEB's determination in the Report that
11 accrual accounting is the default basis to recover pension and OPEB costs in rates. Together
12 with the disposition of the Pension & OPEB Cash Payment Variance Account, it would also
13 reconcile historic pension and OPEB costs incurred by OPG with respect to the prescribed
14 facilities with its historic payment amounts. Consistent with this application, the payment
15 amounts proposed in OPG's future cost-based rates applications would reflect pension and
16 OPEB costs calculated pursuant to the accrual accounting method, in accordance with the
17 Report.

18
19 OPG has made extensive submissions that consistently support the continued use of the
20 accrual accounting method for recovery of pension and OPEB costs, both in EB-2013-0321 and
21 in EB-2015-0040.²⁸ Given the OEB's prior findings that the accrual accounting method is
22 presumptively appropriate for pension and OPEB costs, that OPG was not transitioned away
23 from the accrual basis of recovery, and that utilities remaining on the accrual basis are not
24 required to justify the use of that method, OPG has not re-iterated those submissions in this
25 evidence.²⁹

²⁷ Calculated as \$204.7M (see footnote 26) * 3/8.

²⁸ EB-2013-0321: OPG Argument-in-Chief, dated July 28, 2014, pp. 99-106; and OPG Reply Argument, pp. 172-226.
EB-2015-0040: Initial Written Submissions on the Regulatory Treatment of Pensions and Other Post-Employment
Benefit Costs, dated July 31, 2015; Pension & OPEB Stakeholder Forum Presentation, dated July 19, 2016; and
Submission on Pension and OPEB Cost Recovery, dated September 22, 2016.

²⁹ Consistent with the EB-2013-0321 Decision, OPG has continued to use the accrual accounting method to track,
record and report pension and OPEB costs for regulatory accounting purposes. The OEB has never found that the
accrual accounting method for pension and OPEB costs was inappropriate for OPG, nor has it found that payment
amounts resulting from the use of that method are not just and reasonable.

1 Since OPG's currently approved payment amounts were set based on cash amounts for
2 pension and OPEB costs, there will continue to be a discrepancy between the company's
3 payment amounts and the accrual costs incurred by OPG for the prescribed facilities until OPG's
4 next cost-based payment amounts application. To address this ongoing discrepancy, OPG will
5 continue to record amounts to the Interim Account until the effective date of OPG's next cost-
6 based payment amounts order (currently expected to be January 1, 2022) in accordance with
7 the EB-2016-0152 Payment Amounts Order and the Report.^{30, 31, 32}

8 9 **5.0 APPLICATION OF NEW DIFFERENTIAL ACCOUNT TO AMOUNTS RECOVERED** 10 **FROM THE INTERIM ACCOUNT**

11 This section sets out OPG's proposal for the application of the generic New Differential Account
12 set out in the Report to amounts recovered by OPG from the Interim Account.

13
14 According to the Report, recoveries of amounts recorded in interim cash-to-accrual accounts
15 such as OPG's Interim Account are subject to the New Differential Account. The Report provides
16 that, as these recoveries occur and the balances in the interim accounts are drawn down, there
17 would be a corresponding entry in the New Differential Account. As detailed in Appendix C of
18 the Report, this entry would include prospectively applied carrying charges to amounts
19 recovered, as part of a net (credit) balance in the New Differential Account.

20
21 As it relates to the operation of the New Differential Account, the Report sets out a policy of
22 general application, subject to the specific circumstances of individual utilities. It states that "[it]
23 is open to panels of the OEB in future rate applications to issue revised accounting orders if the
24 evidence in a particular case requires deviations from this policy."³³

³⁰ As the payment amounts were set using forecast cash amounts for pension and OPEB, OPG also would continue to record differences between forecast and actual cash amounts in the Pension & OPEB Cash Payment Variance Account until the effective date of OPG's next cost-based payment amounts order, in accordance with the EB-2016-0152 Payment Amounts Order, Appendix G., p. 12.

³¹ Amounts recorded in the Interim Account effective January 1, 2018 and until the effective date of the next cost-based payment amounts order would not impact amounts, if any, recorded in the New Differential Account during that period. This is because the new account does not apply to amounts recorded in the Interim Account until such time as those amounts are recovered. Based on the proposal in this application, OPG expects that amounts recorded in the Interim Account between January 1, 2018 and the effective date of the next cost-based payment amounts order would be subject to recovery effective after 2021.

³² Report, p. 22.

³³ *Ibid.*, p. 11.

For the reasons set out below, OPG is proposing that recoveries of amounts recorded in the Interim Account as of December 31, 2017 would not be captured in the New Differential Account and therefore not be subject to carrying charges.

5.1 APPLYING THE EB-2013-0321 DECISION

Accounts related to pension and OPEB costs are ultimately governed by the specific OEB payment amount orders and decisions that establish the scope and limits of those accounts.³⁴ Accordingly, while the Report establishes a policy of general application, the disposition of the Interim Account is subject to the parameters established for OPG's prescribed assets in the applicable payment amount orders and decisions.

When the OEB established the Interim Account in EB-2013-0321, it stated that "[a]ny future treatment regarding the deferral account would be limited to the outcomes of the generic proceedings as they relate to the accounting or mechanics of recovery, as applicable."³⁵

The EB-2013-0321 Decision established that OPG is permitted recovery of the Interim Account, to the extent the costs recorded to it are consistent with the regulatory accounting approach and the mechanics of recovery determined in the generic consultation. In effect, the EB-2013-0321 Decision limits the scope of application of the policy in the Report to two governing factors:

- (i) selecting the appropriate regulatory accounting approach, and
- (ii) identifying the appropriate mechanics of recovery.

The Report addressed both governing factors. It established that accrual accounting is the appropriate regulatory accounting approach and identified that the account can be recovered by way of a rate rider over an approved recovery period.³⁶

³⁴ OPG has recorded amounts in the Interim Account in accordance with the parameters prescribed for this account in the following OEB decisions and payment amounts orders: EB-2013-0321 (including as continued in EB-2014-0370) and EB-2016-0152.

³⁵ EB-2013-0321 Decision, p. 89.

³⁶ Report, p.8 and Appendix C, p. 22, respectively.

1 In contrast, the recording of amounts in the New Differential Account is a separate issue, distinct
2 from selecting the regulatory accounting approach or the mechanics of recovery. In OPG's view,
3 the requirement to record corresponding amounts in the New Differential Account is a new policy
4 that was not contemplated in EB-2013-0321 and is not applicable to recovery of the amounts
5 recorded in the Interim Account as at December 31, 2017.

6
7 If the New Differential Account were applied to the proposed recovery of the amounts recorded
8 in the Interim Account, the company would not recover the full amount of accrual costs for that
9 period. Instead, it would recover a reduced amount, net of carrying charges on amounts that
10 would be recorded in the New Differential Account. OPG believes that such an outcome would
11 be inconsistent with the EB-2013-0321 Decision.

12 13 **5.2 CONSISTENT AND FAIR APPLICATION OF NEW POLICY**

14 The majority of utilities' rates reflect the recovery of pension and OPEB costs on an accrual
15 basis. As a result, the New Differential Account will begin to track differences between accrual
16 costs recovered in rates and cash payments made by utilities, and accrue carrying costs (as
17 applicable) for these utilities commencing January 1, 2018. For the period prior to January 1,
18 2018, those utilities were able to recover the full pension and OPEB accrual costs as they did
19 not have an obligation to record differences between cash and accrual methods in an account
20 comparable to OPG's Interim Account and, accordingly, are not subject to the New Differential
21 Account in respect of those differences.

22
23 OPG's proposal ensures that OPG receives the same effective treatment as other utilities. If,
24 instead, the New Differential Account were to apply to recoveries of Interim Account balances
25 recorded as of December 31, 2017, then OPG would receive a reduced amount in respect of
26 its pension and OPEB accrual costs for that period. This would result in an inconsistent and
27 unfair application of OEB policy across the regulated utilities, resulting in financial advantage to
28 some and financial disadvantage to OPG.

29
30 The scenario in Chart 1 below illustrates how applying the New Differential Account to the
31 recovery of the Interim Account balance would produce inconsistent and unfair financial impacts

1 on similarly situated utilities. This scenario compares two illustrative utilities that are identical
2 except for the funding of pension and OPEB costs in rates:

- 3 • Utility A, whose rates were set using the accrual basis for pension and OPEB costs, and
- 4 • Utility B, whose rates were temporarily set on the basis of pension and OPEB cash amounts,
5 with a deferral account to capture the difference between the cash amounts and the accrual
6 costs (i.e., an Interim Account), during an illustrative interim period of 2015-2017.

7

Chart 1: Illustrative Example^{37, 38}

Line	Particulars (\$M)	2015	2016	2017	2018	2019	2020	2021	Total
Timing of Recovery:									
1	Utility A Cash Flow - Accrual Costs in Rates	100	100	100	0	0	0	0	300
2	Utility B Cash Flow - Accrual Costs in Riders	0	0	0	100	100	100	0	300
3	Annual Cash Flow Difference (line 1 - line 2)	100	100	100	(100)	(100)	(100)	0	0
4	Cumulative Cash Flow Difference / Interim Account Balance*	100	200	300	200	100	0	0	N/A
5	Annual Interest impact on cumulative cash flow differences due to timing of recovery**	1.7	5.3	8.8	8.8	5.3	1.8	0.0	31.4
New Differential Account:									
6	Annual Cash to Accrual Difference Tracked	0	0	0	100	100	100	0	300
7	Cumulative Cash to Accrual Difference Tracked***	0	0	0	100	200	300	300	N/A
8	Annual Interest impact on cumulative cash to accrual difference due to carrying charges****	0.0	0.0	0.0	1.8	5.3	8.8	10.5	26.3
Notes									
* Prior year Cumulative Cash Flow (line 4) plus current year Annual Cash Flow Difference (line 3)									
** [Prior year Cumulative Cash Flow (line 4) plus current year Cumulative Cash Flow (line 4)] / 2 * 3.5% interest rate									
*** Prior year Cumulative Account Balance (line 7) plus current year Annual Amount Recorded (line 6)									
**** [Prior year Cumulative Account Balance (line 7) plus current year Cumulative Account Balance (line 7)] / 2 * 3.5% interest rate									

This scenario demonstrates how differences in timing of recovery of pension and OPEB accrual costs for the interim period and the inconsistent treatment of the New Differential Account would confer two financial benefits on Utility A relative to Utility B: increased cash flow, and lower carrying charges recorded in the New Differential Account.

Inconsistent Cash Flow: As shown in line 4, Utility A has a higher cash flow than Utility B, and therefore, Utility B would incur approximately \$30M in interest costs (line 5) that Utility A would not, over the period shown. Although this difference in cash flow, due to the timing of recovery of pension and OPEB accrual costs for the interim period, is a source of relative

³⁷ The scenario assumes that both utilities:

- 1) incur the exact same accrual costs and cash amounts each year;
- 2) received OEB-approved rates effective January 1, 2015;
- 3) incurred accrual costs that were \$100M greater than cash amounts for each of 2015, 2016 and 2017;
- 4) incur accrual costs equal to cash amounts for each of 2018, 2019 and 2020 (i.e., to focus the financial impact of this example on the treatment of cash-to-accrual differences prior to the January 1, 2018 effective date of the New Differential Account); and
- 5) incur simple interest equal to the current OEB-prescribed interest rate for construction work in progress (3.35%) for cash flow differences and are subject to interest at this same rate on the cash-to-accrual differences tracked in the New Differential Account.

³⁸ The scenario assumes that Utility B receives, through a rate rider, \$100M per year to recover its December 31, 2017 Interim Account balance over a three-year term from January 1, 2018 through December 31, 2020. The half-year rule is used to calculate interest on amounts arising during a year.

1 inequality between utilities with the exact same costs, OPG is not proposing that the OEB
2 address this issue.

3
4 **Inconsistent Carrying Charges:** Since Utility B's rates were temporarily set on the basis of
5 cash amounts, it recorded amounts at line 4 in its Interim Account. The December 31, 2017
6 balance of \$300M in the account is recovered through a rate rider ending December 31, 2020
7 (line 2). Recovered amounts are tracked annually in the New Differential Account (line 6), and
8 carrying charges (line 8) are charged on the cumulative balance (line 7). Over the period in
9 Chart 1, the carrying charges owing to customers from Utility B total over \$25M (line 8). Since
10 Utility A was never required to establish an Interim Account (and therefore had no recoverable
11 balance to track in the New Differential Account), only Utility B must pay these carrying
12 charges.

13
14 As shown in line 8, annual carrying charges (\$10M in this example) in connection with the
15 balance of the Interim Account recovered by the end of 2020 will continue to apply to Utility B
16 for 2021 and beyond. Utility B must continue to pay these annual carrying charges until its
17 cumulative cash payments from January 1, 2018 (the effective date of the OEB's pension and
18 OPEB policy) exceed its cumulative accrual costs by \$300M. In effect, until Utility B has paid
19 \$300M more toward pension and OPEB than customers have paid the utility for pension and
20 OPEB costs (January 1, 2018 onward), Utility B must continue to pay carrying charges. Utility
21 A has no such requirement and therefore avoids these carrying charges.

22
23 OPG's proposal, as set out in Section 5.0, would remedy the inconsistency arising from the
24 application of carrying charges to the Interim Account balance.

25
26 The OEB typically applies policies of general application in a manner that is consistent across
27 utilities and, in OPG's view, such consistent application of policy is a key element of fair
28 regulation. In the circumstances, a consistent application of OEB policy would require that OPG
29 should be on equal footing with those utilities for whom the OEB did not establish interim
30 accounts. Accordingly, the recovery of amounts recorded in the Interim Account as of December
31 31, 2017 should not to be subject to the New Differential Account.

DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's deferral and variance accounts and presents the amounts recorded in these accounts as of December 31, 2017 that are proposed for clearance in this Application. These accounts were established pursuant to O. Reg. 53/05 and the OEB's decisions as noted in the EB-2016-0152 Payment Amount Order (the "PAO"), Appendix G and Appendix H and the EB-2018-0002 Decision and Order.

2.0 OVERVIEW

OPG proposes to clear the audited balances in all deferral and variance accounts as at December 31, 2017, less amortization amounts previously approved by the OEB in EB-2016-0152, with the exception of the Capacity Refurbishment Variance Account ("CRVA") and the Fitness for Duty Deferral Account. OPG's proposal is consistent with the OEB's decision and order in the EB-2016-0152 proceeding, which states that "OPG may file to dispose of applicable audited deferral and variance account balances at the same time as its application for 2019 hydroelectric payment amounts in calendar year 2018."¹ OPG proposes to defer the clearance of the CRVA and the Fitness for Duty Deferral Account to a future application.

The total year-end 2017 debit balance in the accounts proposed for clearance is \$288.9M² for the regulated hydroelectric facilities and \$1,198.6M³ for the nuclear facilities.⁴ Adjusted for the 2018-2020 amortization amounts approved in EB-2016-0152, these balances are \$205.4M⁵ for the regulated hydroelectric facilities and \$911.6M⁶ for the nuclear facilities. Details regarding proposed account clearance and payment riders are presented in Ex. H1-2-1.

The audited balances in each of the deferral and variance accounts are shown in Ex. H1-1-1 Table 1. The Schedule of Regulatory Balances as at December 31, 2017 supporting these

¹ EB-2016-0152 Decision and Order, p. 119.

² Ex. H1-1-1, Table 1, col. (b), line 13 less line 6.

³ Ex. H1-1-1 Table 1, col. (b): line 33 less lines 18, 19 and 30.

⁴ A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.

⁵ Ex. H1-2-1, Table 1, col. (c), line 13 less line 6.

⁶ Ex. H1-2-1, Table 2, col. (c), line 19 less lines 5, 6 and 17.

balances is presented as Attachment 1. Ernst & Young LLP's unqualified Independent Auditors' Report on the Schedule of Regulatory Balances in Attachment 1 is presented as Attachment 2.

The following information is provided in this exhibit:

- Section 3.0 lists OPG's existing deferral and variance accounts as at December 31, 2017.
- Section 4.0 describes the process by which the December 31, 2017 balances in deferral and variance accounts were determined.
- Section 5.0 describes the existing deferral and variance accounts and how additions to the accounts have been determined. In this Application, OPG is not proposing any changes to the deferral and variance accounts approved in the EB-2016-0152 PAO and the EB-2018-0002 Decision and Order, including descriptions of the accounts and the methodologies used to determine additions to the accounts.
- Section 6.0 discusses the application of interest to the balances in the accounts.

3.0 LISTING OF EXISTING ACCOUNTS

The OEB has authorized deferral and variance accounts for OPG as listed below. For the January 1, 2016 to May 31, 2017 period, accounts were authorized pursuant to the EB-2014-0370 Payment Amounts Order, the EB-2014-0369 Decision and Order and the EB-2015-0374 Decision and Order. Effective June 1, 2017, pre-existing accounts were continued and new accounts were authorized pursuant to Appendix G and Appendix H of the EB-2016-0152 PAO.⁷

Pre-Existing Accounts continued in the EB-2016-0152 PAO: ⁸

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts

⁷ In addition, the EB-2018-0002 Decision and Order issued on May 31, 2018 established the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018. As this account was not in effect as of December 31, 2017, it is not discussed further in this Application.

⁸ EB-2016-0152 PAO, p. 11, para. 7.

- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Pension & OPEB Cash Payment Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
- Nuclear Deferral and Variance Over/Under Recovery Variance Account
- Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

Newly authorized accounts in the EB-2016-0152 PAO:⁹

- Rate Smoothing Deferral Account
- Fitness for Duty Deferral Account
- SR&ED ITC Variance Account.

4.0 ACCOUNT BALANCES

This section describes the process by which the December 31, 2017 account balances were determined.

The 2015 audited balances approved in the EB-2016-0152 PAO are the starting point for the account continuity tables provided at Ex. H1-1-1, Table 1a (2016), Table 1b (January 1, 2017

⁹ EB-2016-0152 PAO, p. 13 para. 12.

1 to May 31, 2017) and Table 1c (June 1, 2017 to December 31, 2017). The 2015 audited
2 balances for the applicable deferral and variance accounts listed in Section 3.0 above were
3 approved by the OEB for recovery as provided in the EB-2016-0152 PAO Appendix D, Table
4 1, col. (a) for the regulated hydroelectric facilities and Appendix E, Table 1, col. (a) for the
5 nuclear facilities. The continuity tables show, for each account, the closing balance for the prior
6 period, additions (labelled "Transactions"), amortization subtracted and interest added, any
7 transfers between accounts during the period, and the closing account balances. Exhibit H1-
8 1-1 Tables 2 through 15 provide supporting calculations showing the derivation of 2016 and
9 2017 additions into the accounts OPG proposes to clear in this Application.

10
11 Additions from January 1, 2016 through May 31, 2017 have been calculated with reference to
12 amounts underpinning the payment amounts approved in EB-2013-0321, unless otherwise
13 specified in an account's description, in accordance with the EB-2014-0370 Payment Amounts
14 Order and based on a June 1, 2017 effective date of the EB-2016-0152 payment amounts.

15
16 In accordance with the EB-2016-0152 PAO, as of the PAO's effective date, additions to the
17 regulated hydroelectric accounts are calculated with reference to amounts underpinning the
18 hydroelectric payment amounts approved in EB-2013-0321 and additions to the nuclear
19 accounts are calculated with reference to amounts underpinning the corresponding nuclear
20 revenue requirement approved in EB-2016-0152, unless specified otherwise in an account's
21 description. Therefore, additions from June 1, 2017 through December 31, 2017 have been
22 calculated in accordance with the EB-2016-0152 PAO.

23
24 The amortization presented for 2016 in Ex. H1-1-1 Table 1a, col. (c) is per the EB-2014-0370
25 Payment Amounts Order. No amortization was authorized by the OEB for any of the accounts
26 for 2017.

27
28 Except for accounts that do not attract interest as noted below, interest has been applied to
29 the monthly opening balances of the accounts at the OEB-prescribed interest rates of 1.10%
30 per annum for January 1, 2016 through September 30, 2017 and 1.50% per annum for October
31 1, 2017 through December 31, 2017, pursuant to the applicable orders of the OEB.

5.0 ACCOUNT DESCRIPTIONS AND ENTRIES

This section provides brief descriptions of the deferral and variance accounts and the reasons for the credits and debits to the accounts in 2016 and 2017 that OPG seeks to clear in this Application. OPG has made no changes to the accounts or the process by which entries are recorded to the accounts since they were last approved by the OEB.¹⁰ As part of the payment amounts order process for this Application, OPG intends to adopt the account definitions approved by the OEB in both the EB-2016-0152 PAO and EB-2018-0002 Decision and Order.

5.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and all subsequent OPG applications.

This account records the financial impact of differences, including changes in gross revenue charge ("GRC") costs, between the actual production amount for the regulated hydroelectric facilities and the reference production values, arising from changes in actual water conditions. The account applies to the five hydroelectric generating stations subject to rate regulation by the OEB since 2008 ("previously regulated hydroelectric facilities") and 21 of the 48 hydroelectric generating stations that became subject to OEB rate regulation effective July 1, 2014 ("newly regulated hydroelectric facilities"). These 21 facilities are as listed in EB-2016-0152 Ex. H1-1-1, Attachment 3.

The account additions for January 1, 2016 through December 31, 2017 are based on the production forecast methodology approved in EB-2013-0321 and EB-2014-0370 and reflected in the EB-2016-0152 PAO (Appendix G, pp. 3-4). The derivation of account entries for 2016 and 2017 is shown in Ex. H1-1-1 Table 2.

Due to favourable water supply conditions (i.e., precipitation) affecting the Niagara River in 2016, the calculated actual hydroelectric production was higher than the reference forecast

¹⁰ Per EB-2016-0152 PAO and EB-2018-0002 Decision and Order.

1 production by 1,320 GWh for the previously regulated hydroelectric facilities. This was partially
2 offset by slightly lower calculated actual production for the newly regulated hydroelectric
3 facilities of 197 GWh. These variances resulted in a net credit addition of \$33.0M to the account
4 in 2016. In 2017, the calculated actual hydroelectric production was higher than the reference
5 forecast production by 1,958 GWh for the previously regulated hydroelectric facilities and 1,304
6 GWh for the newly regulated hydroelectric facilities, due to favourable water supply conditions
7 affecting multiple river systems across the province, particularly the Niagara, St. Lawrence,
8 Madawaska and Ottawa Rivers. These variances resulted in a net credit entry of \$98.0M to
9 the account in 2017.

11 **5.2 Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear** 12 **Sub Accounts**

13 The Ancillary Services Net Revenue Variance Account was originally established by O. Reg.
14 53/05. It was subsequently approved in EB-2007-0905 and has been approved in all
15 subsequent OPG applications.

17 The account is divided into the Ancillary Services Net Revenue Variance Account –
18 Hydroelectric, and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts.
19 Ancillary services for regulated hydroelectric operations include black start capability,
20 operating reserve, regulation service, and reactive support/voltage control service. Ancillary
21 services for nuclear operations include reactive support/voltage control service.

23 The derivation of account entries for 2016 and 2017 is shown in Ex. H1-1-1 Table 3.

25 Hydroelectric ancillary revenues in 2016 and 2017 were higher than the reference amounts
26 that reflect the forecasts underpinning the revenue requirement approved in EB-2013-0321,
27 primarily due to higher regulation service revenue and operating reserve revenue, partially
28 offset by lower reactive support revenue. These factors resulted in credit entries to the
29 Hydroelectric Sub Account of \$9.9M in 2016 and \$21.2M in 2017.¹¹

¹¹ For January 1, 2016 through May 31, 2017, as per the EB-2014-0370 Payment Amounts Order, adjustments were made to ensure that amounts recorded in the account did not include those that OPG indicated in EB-2013-

1 Nuclear ancillary revenues in January 1, 2016 through May 31, 2017 were lower than the
2 reference amount that reflected the forecasts underpinning the revenue requirement approved
3 in EB-2013-0321, mainly due to lower reactive support revenue. Similarly, reactive support
4 revenue resulted in lower nuclear ancillary revenues than the reference amount that reflected
5 the forecast underpinning the 2017 revenue requirement approved in EB-2016-0152, for June
6 1, 2017 through December 31, 2017. These factors resulted in debit entries to the Nuclear Sub
7 Account of \$1.3M in 2016 and \$1.1M in 2017.¹²

8 9 **5.3 Hydroelectric Incentive Mechanism Variance Account**

10 The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-
11 0008 and has been approved in all subsequent OPG applications. This account records a
12 credit to ratepayers of 50 per cent of hydroelectric incentive mechanism ("HIM") revenues
13 above an OEB-specified threshold.

14
15 There were no additions to the account for 2016 or 2017 as actual HIM revenues of \$14.0M in
16 2016 and \$12.4M in 2017 were significantly below the specified threshold of \$54.5M¹³, as
17 shown in Ex. H1-1-1 Table 4.

18 19 **5.4 Hydroelectric Surplus Baseload Generation Variance Account**

20 The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in
21 EB-2010-0008 and has been approved in all subsequent OPG applications. This account
22 records the financial impact of foregone production at the regulated hydroelectric facilities due
23 to surplus baseload generation ("SBG") conditions at the previously regulated hydroelectric
24 facilities and 21 newly regulated hydroelectric facilities identified in EB-2016-0152 Ex. H1-1-1,
25 Attachment 3. The amount recorded in the account is net of avoided GRC costs. The account
26 additions for January 1, 2016 through December 31, 2017 are based on the methodology to

0321 it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence in EB-2013-0321 dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts were outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

¹² *Ibid.*

¹³ The threshold amount of \$54.5M is described in the EB-2016-0152 PAO, App G, p.5

1 calculate foregone production due to SBG conditions reviewed in EB-2013-0321 and reflected
2 in the EB-2016-0152 PAO (Appendix G, pp. 6-7).

3 The derivation of account entries for 2016 and 2017 is shown in Ex. H1-1-1 Table 5. Actual
4 foregone production due to SBG conditions in 2016 was approximately 2,744 GWh for the
5 previously regulated hydroelectric facilities and 1,525 GWh for the newly regulated
6 hydroelectric facilities. For 2017, actual foregone production due to SBG conditions was
7 approximately 3,721 GWh for the previously regulated hydroelectric facilities and 1,504 GWh
8 for the newly regulated hydroelectric facilities. Net of avoided GRC costs, the resulting debit
9 entries in the account were \$125.6M in 2016 and \$147.1M in 2017.

11 **5.5 Income and Other Taxes Variance Account**

12 The Income and Other Taxes Variance Account was originally approved in EB-2007-0905 and
13 has been approved in all subsequent OPG applications. This account records the financial
14 impact on the revenue requirement of the following:

- 16 • Any differences in payments in lieu of corporate income or capital taxes that result from
17 a legislative or regulatory change to the tax rates or rules of the *Income Tax Act*
18 (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act*
19 (Ontario), as modified by the regulations under the *Electricity Act*, 1998, and any
20 differences in payments in lieu of property tax to the Ontario Electricity Financial
21 Corporation that result from changes to the regulations under the *Electricity Act*, 1998;
- 22 • Any differences in municipal property taxes that result from a legislative or regulatory
23 change to the tax rates or rules for OPG's prescribed assets under the *Assessment*
24 *Act*, 1990;
- 25 • Any differences in payments in lieu of corporate income or capital taxes that result from
26 a change in, or a disclosure of, a new assessing or administrative policy that is
27 published in the public tax administration or interpretation bulletins by relevant federal
28 or provincial tax authorities, or court decisions on other taxpayers; and
- 29 • Any differences in payments in lieu of income or capital taxes that result from
30 assessments or re-assessments (including re-assessments associated with the
31 application of the tax rates and rules to OPG's regulated operations or changes in

1 assessing or administrative policy including those arising from court decisions on other
2 taxpayers).

3 OPG recorded three entries in this account in 2016 and 2017, as follows:

- 4 1) A credit entry related to an increase in the recognition of Scientific Research and
5 Experimental Development ("SR&ED") Investment Tax Credits ("ITCs") for the 2012
6 taxation year from 75% to 100%, based on the resolution of the 2012 income tax audit
7 in 2016;
- 8 2) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2013
9 taxation year from 75% to 100%, based on the resolution of the 2013 income tax audit
10 in 2017;¹⁴
- 11 3) A debit entry related to a reduction to the rate for the Ontario Research and
12 Development Tax Credit (reported as part of SR&ED ITCs) from 4.5% to 3.5% of
13 qualifying expenditures, effective June 1, 2016. For the nuclear facilities, the entry
14 applies up to June 1, 2017 because the impact of this rate change was reflected in the
15 EB-2016-0152 approved revenue requirement.¹⁵ The entry applies to the regulated
16 hydroelectric facilities for the full year 2017.¹⁶

17
18 Entries 1) and 2) are the same in nature and calculation as the equivalent SR&ED ITC impacts
19 previously recorded in the account in relation to resolution of prior year income tax audits. The
20 entries recognize a credit to ratepayers of an additional 25% of the benefit of SR&ED ITCs in
21 relation to 2012 and 2013 that were previously credited to ratepayers at 75% through a
22 combination of the EB-2010-0008 payment amounts¹⁷ and the Income and Other Taxes
23 Variance Account balances approved in EB-2012-0002 and EB-2014-0370.

24

¹⁴ As discussed in section 5.18 below, the EB-2016-0152 PAO approved, effective June 1, 2017, the SR&ED ITC Variance Account to record the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB, including the tax on the difference. Therefore, the impact of tax audit resolution for 2017 taxation years onwards (attributed to the nuclear facilities and, for 2017, pro-rated for the effective date of the account) will be recorded in the SR&ED ITC Variance Account rather than the Income and Other Taxes Variance Account.

¹⁵ See EB-2016-0152 Ex. F4-2-1, section 3.4

¹⁶ The regulated hydroelectric debit entry is less than \$0.05M.

¹⁷ The EB-2010-0008 payment amounts were in effect from March 1, 2011 to October 31, 2014.

As shown in the derivations at Ex. H1-1-1 Table 6, the combined impact of these entries for 2016 is a net credit addition to the account of \$3.1M (\$3.1M for nuclear and \$0.0M for regulated hydroelectric) and for 2017 a net credit of \$2.5M (\$2.5M for nuclear and \$0.0M for regulated hydroelectric).

5.6 Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. The account records the financial impact of variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in O. Reg. 53/05 s. 2 and those forecast costs and firm financial commitments for projects reflected in the revenue requirement approved by the OEB. The account includes assessment costs and pre-engineering costs and commitments as required by O. Reg. 53/05 s. 6(2)4.

Regulated Hydroelectric

The total hydroelectric entries to the account over the January 1, 2016 to December 31, 2017 period are a debit of \$5.2M.¹⁸ Per the EB-2016-0152 PAO (Appendix G, p. 9), commencing on the effective date of the 2017 approved hydroelectric payment amounts for the regulated hydroelectric facilities, OPG is entitled to recover amounts recorded in the CRVA in relation to the regulated hydroelectric facilities to the extent that OPG's total capital in-service capital additions for these facilities exceed the funding available for capital expenditures calculated as set out in EB-2016-0152 Ex. H1-1-2, Table 3, col. (a).¹⁹

Given the above recoverability condition, as the 2017-2021 IR period has four years remaining as of December 31, 2017, this Application is not seeking clearance of the hydroelectric amounts in the account. OPG proposes to defer the clearance to a future application, which would provide the necessary details to support an assessment of the recoverability of any hydroelectric amounts recorded in the account over the IR period.

¹⁸ Ex. H1-1-1: Table 1a, line 6, col. (b) plus Table 1b, line 6, col. (b) plus Table 1c, line 6, col. (b).

¹⁹ Subject to annual escalation by the approved price cap index applied to the hydroelectric payment amount

Nuclear

The total nuclear entries to the account over the January 1, 2016 to December 31, 2017 period are a credit of \$14.8M.²⁰ As contemplated by the EB-2016-0152 PAO and set out in O. Reg. 53/05, these net additions include debit and credit entries for the financial impact of variances between the actual capital and non-capital costs incurred for the Darlington Refurbishment Program (“DRP”) over this period and such forecast amounts reflected in the corresponding nuclear revenue requirements approved by the OEB in EB-2013-0321 and EB-2016-0152.

As the DRP-related variances include those related to the refurbishment of Darlington Unit 2, which is in progress, this Application is not seeking clearance of the nuclear amounts in the account. OPG proposes to defer the clearance to a future application, which would allow an assessment of the recoverability of DRP-related variances in the context of the overall performance of the Unit 2 refurbishment.

5.7 Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090 and was continued in subsequent proceedings. This account records the difference between: (i) the pension and OPEB costs, plus related income tax PILs, reflected in the revenue requirement approved by the OEB; and (ii) OPG’s actual pension and OPEB costs, and associated income tax impacts, for the prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference are calculated on an accrual basis using the same accounting standards as those used to derive the reference amount.

There are two approved components of the account:

- 1) Future Recovery component: the OEB has approved the recovery of the balance over the period to December 31, 2024. Adjusted for the amortization amounts approved in

²⁰ Ex. H1-1-1: Table 1a, line 18, col. (b) plus Table 1a, line 19, col. (b) plus Table 1b, line 18, col. (b) plus Table 1b, line 19, col. (b) plus Table 1c, line 18, col. (b) plus Table 1c, line 19, col. (b).

the EB-2016-0152 PAO, the remaining balance for recovery is \$6.3M for regulated hydroelectric²¹ and \$128.8M for nuclear²²; and

- 2) Post 2012 Additions: the OEB has approved the recovery of the balance over a period of 72 months commencing July 1, 2015 to June 30, 2021. Adjusted for amortization approved in the EB-2016-0152 PAO, the remaining balance for recovery is \$14.8M for regulated hydroelectric²³ and \$282.7M for nuclear²⁴.

No additions or interest were recorded in the Pension and OPEB Cost Variance Account in 2016 or 2017, pursuant to the corresponding payment amounts orders.

5.8 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on the actual regulated hydroelectric production and approved riders. The account also includes the transfer of the regulated hydroelectric portions of the balances in accounts as they expire from time to time.

The derivation of the \$11.7M debit entry to the account for 2016 is shown in Ex. H1-1-1 Table 8. Since there were no riders effective in 2017, there were no additions in 2017. There were no transfers in 2016 or 2017.

5.9 Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was originally approved in EB-2013-0321 and has been approved in all subsequent OPG applications. It records the cost impact of a gross revenue charge reduction under O. Reg. 124/02, once approved by the Ontario Ministry of

²¹ Ex. H1-2-1, Table 1, line 8, col. (c).

²² Ex. H1-2-1, Table 2, line 11, col. (c).

²³ Ex. H1-2-1, Table 1, line 9, col. (c).

²⁴ Ex. H1-2-1, Table 2, line 12, col. (c).

1 Natural Resources and Forestry, pertaining to production increases at OPG's Sir Adam Beck
2 plants due to the operation of the new Niagara tunnel.

3
4 As no decision on the GRC reduction has been issued by the Ministry of Natural Resources
5 and Forestry to date, there have been no amounts recorded in the account since its inception.

6
7 **5.10 Pension & OPEB Cash Payment Variance Account**

8 The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and
9 continued in EB-2014-0370 and EB-2016-0152. It records the difference between OPG's
10 actual registered pension plan contributions ("RPP") and other post-employment benefit
11 ("OPEB") plan payments (including the long-term disability benefit plan) attributed to the
12 prescribed generating facilities, and such forecast amounts underpinning the revenue
13 requirement approved by the OEB.

14
15 RPP contributions attributed to the prescribed facilities for 2016 and for January 1, 2017
16 through May 31, 2017 were lower than the reference amounts that reflect the forecasts
17 underpinning the revenue requirement approved in EB-2013-0321, reflecting the results of the
18 actuarial valuation of the RPP as of January 1, 2016 filed with the Financial Services
19 Commission of Ontario ("FSCO") in September 2016. As discussed in EB-2016-0152, Ex. N1-
20 1-1 and Ex. L-6.6-1 Staff-156, the 2016 valuation resulted in a reduction in minimum required
21 contributions relative to the previous valuation that underpinned the EB-2013-0321 forecasts,
22 due to lower going concern special payments. OPEB payments attributed to the prescribed
23 facilities for 2016 were higher than the reference amounts, mainly due to retirements, and
24 largely unchanged from the reference amounts for January 1, 2017 through May 31, 2017.

25
26 RPP contributions attributed to the prescribed facilities for June 1, 2017 through December 31,
27 2017 were lower than the reference amounts that reflect the forecast underpinning the revenue
28 requirement approved in EB-2016-0152, reflecting the results of a subsequent actuarial
29 valuation of the RPP as of January 1, 2017 filed with the Financial Services Commission of
30 Ontario ("FSCO") in September 2017. The 2017 valuation resulted in a reduction in minimum
31 required contributions relative to the 2016 valuation that underpinned the EB-2016-0152

1 forecasts, primarily due to lower going concern special payments. OPEB payments attributed
2 to the prescribed facilities for the period were largely unchanged from the reference amounts.

3
4 As shown in the derivations at Ex. H1-1-1 Table 7, line 6 the above variances yielded credit
5 entries of \$85.5M (\$73.8M for nuclear and \$11.7M for regulated hydroelectric) in 2016 and
6 \$80.7M (\$62.5M for nuclear and \$18.2M for regulated hydroelectric) in 2017.

7
8 In calculating the above variances, OPG's total RPP contributions and OPEB benefit payments
9 were attributed to the prescribed facilities using the same methodology as in the previous
10 proceedings. OPG's total RPP contributions and OPEB benefit payments for the above periods
11 can be found in an independent actuary's report from Aon Hewitt in support of the balances in
12 the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus
13 Accrual Differential Deferral Account.²⁵ The report is included as Attachment 3 to this exhibit.

14 15 **5.11 Pension and OPEB Cash Versus Accrual Differential Variance Account**

16 The Pension & OPEB Cash Versus Accrual Differential Deferral Account was approved in EB-
17 2013-0321 and continued in EB-2014-0370 and EB-2016-0152. The account records
18 differences between: (i) OPG's actual pension and OPEB costs for its prescribed generating
19 facilities determined using the accrual accounting method applied in OPG's audited
20 consolidated financial statements; and, (ii) OPG's actual registered pension plan contributions
21 and other post-employment benefit plan payments (including the long-term disability benefit
22 plan) attributed to OPG's prescribed generating facilities. The account is tracked separately for
23 the regulated hydroelectric and nuclear prescribed assets, and no interest is recorded on the
24 balances.

25
26 The total December 31, 2017 debit balance in the regulated hydroelectric portion of the account
27 accumulated since November 1, 2014 is \$83.2M, as shown in Ex. H1-1-1 Table 1, line 10, col.
28 (c). The derivation of the \$39.0M regulated hydroelectric debit entries to the account during
29 2016 and 2017 is shown in Ex. H1-1-1 Table 7, line 11 (col. (a) + col. (j)).

30

²⁵ Attachment 3, pp. 9-10.

1 The total December 31, 2017 debit balance in the nuclear portion of the account accumulated
2 since November 1, 2014 is \$530.5M, as shown in Ex. H1-1-1 Table 1, line 26, col. (c). The
3 derivation of the \$259.4M nuclear debit entries to the account during 2016 and 2017 is shown
4 in Ex. H1-1-1 Table 7, line 11 (col. (b) + col. (k)).

5
6 The derivation of the nuclear and regulated hydroelectric debit entries in the account for
7 November 1, 2014 to December 31, 2014 and for full year 2015 is shown in Ex. H1-1-1 Table
8 7a. These calculations were previously presented in EB-2016-0152 Ex. H1-1-1, Table 8 for
9 2015 and EB-2016-0152 Ex. L-9.1-1, Staff-209, Attachment 1, Table 1 for 2014.

10
11 Actual pension and OPEB accrual costs for the full period November 1, 2014 to December 31,
12 2017 used in the calculation of the account entries were determined using the method applied
13 in OPG's audited consolidated financial statements for the corresponding years prepared in
14 accordance with US GAAP. In calculating the entries, OPG's total accrual pension and OPEB
15 costs were attributed to the prescribed facilities using the same methodology as in the previous
16 proceedings. OPG's total accrual pension and OPEB costs for the period January 1, 2016
17 through December 31, 2017 can be found in Aon Hewitt's independent actuary's report
18 included as Attachment 3 to this exhibit.²⁶ OPG's total accrual pension and OPEB costs for
19 the period November 1, 2014 to December 31, 2015 can be found in a similar Aon Hewitt
20 independent actuary's report found at EB-2016-0152, Ex. F4-3-2, Attachment 2, which is
21 included as Attachment 4 to this exhibit. The accrual accounting methodology used in
22 determining the costs is described in detail in EB-2016-0152 Ex. F4-3-2, section 5.0 and EB-
23 2016-0152 Ex. N1-1-1, section 3.1.2.

24
25 Chart 1 below presents the assumptions used to determine the 2016 and 2017 actual pension
26 and OPEB actual costs. The process for development of these assumptions is discussed in
27 EB-2016-0321 Ex. F4-3-2, section 5.1 and EB-2016-0152 Ex. N1-1-1, section 3.1.2. The
28 assumptions used to determine the 2014 and 2015 actual pension and OPEB accrual costs
29 are as provided in EB-2016-0152 Ex. F4-3-2, Chart 5 and discussed in that exhibit.

30

²⁶ Attachment 3, p. 5.

**Chart 1: Pension and OPEB Accrual Cost Assumptions for 2016 and 2017
(rate per annum)**

	2016 Actual	2017 Actual
Discount rate for pension	4.10%	Current service cost – 4.15% Interest cost – 3.37% ²⁷
Discount rate for other post-retirement benefits	4.20%	Current service cost – 4.21% Interest cost – 3.58% ²⁷
Discount rate for long-term disability ²⁸	3.10%	Current service cost – 3.10% Interest cost – 2.46% ²⁷
Expected long-term rate of return on pension fund assets	6.0%	6.0%
Inflation rate	2.0%	2.0%
Weighted average salary schedule escalation rate ²⁹	1.6% from January 1, 2016 to December 31, 2021 and 2.5% thereafter	1.8% from January 1, 2017 to December 31, 2021 and 2.5% thereafter

As anticipated, with the exception of the LTD costs that are calculated using information as of December 31, 2016, the 2016 actual accrual costs were close or equal to the 2016 projected costs provided in EB-2016-0152, as the projection was determined using the final assumptions as of December 31, 2015.³⁰ The actual LTD costs were lower than those projected primarily due to the impact of a comprehensive accounting valuation conducted to determine OPG's

²⁷ The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year under the Full Yield Curve Approach adopted beginning in 2017. Under that approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. This rate is 3.95% for pension costs, 4.13% for other post-retirement benefit costs and 2.70% for LTD costs for 2017.

²⁸ As the LTD costs for the year are based on the re-measurement of the benefit obligation at the end the year in accordance with US GAAP, the total LTD costs inclusive of any actuarial gains or losses due to the re-measurement continue to reflect the discount rate used to determine the year-end benefit obligations, notwithstanding the adoption of the Full Yield Curve Approach. For December 31, 2017, this discount rate was 3.09%.

²⁹ The weighted average salary schedule escalation rate of 1.6% per year and 1.8% per year for 2016 and 2017, respectively, to the end of 2021 reflects the following: 1.0% per year to the end of 2017 for represented by the Power Workers' Union and 1.0% to the end of 2018 for employees represented by the Society of United Professionals, consistent with existing collective agreement provisions, and 2.0% per year (i.e. inflation rate) thereafter. The long-term salary schedule escalation (after 2021) is equal to the assumed inflation rate plus 0.5%, as in EB-2013-0321 and EB-2016-0152.

³⁰ Total OPG projected costs for 2016 can be found in EB-2016-0152 Ex .F4-3-2, Attachment 1, p. 5 and p. 9, with the corresponding amounts attributed to the nuclear facilities at EB-2016-0152 Ex. F4-3-2, p. 19, Chart 6.

1 year-end 2016 plan obligations, reflected through an actuarial gain recorded at the end of
2 2016.³¹

3 As discussed in detail in EB-2016-0152 Ex. N1-1-1, section 3.1.2, the 2017 accrual costs
4 reflect the adoption of the Full Yield Curve Approach to determining the current service and
5 interest cost components of pension and OPEB costs starting in 2017. The adoption of the Full
6 Yield Curve Approach had the effect of lowering the accrual costs in 2017.

7
8 The 2017 actual accrual costs for pension were lower than the 2017 projected costs provided
9 in EB-2016-0152 and close to the EB-2016-0152 projection for OPEB.³² The decrease in
10 pension costs was mainly due to higher than projected discount rates as at December 31,
11 2016, partially offset by a lower than expected year-end 2016 pension fund asset value for
12 fixed income investments.

13
14 On a year-over-year basis, the adoption of the Full Yield Curve Approach, as well as the
15 negative expected net growth in cost components due to the increase in the pension asset
16 value and lower amortization of historical net actuarial losses under the corridor approach,
17 reduced pension costs in 2017 compared to 2016, partially offset by the impact of lower
18 discount rates as at December 31, 2016 used to determine the 2017 costs.³³

19
20 Actual OPEB costs increased from 2016 to 2017. This reflected the reduction in 2016 costs
21 due to the LTD actuarial gain and the effect of lower discount rates as at December 31, 2016
22 used to determine the 2017 OPEB costs, partially offset by the impact of lower expected per
23 capita health care benefit costs reflecting lower costs of prescription drugs as part of the
24 comprehensive accounting valuation and the adoption of the Full Yield Curve Approach.

³¹ As discussed in EB-2016-0152 Ex. N1-1-1, comprehensive accounting valuations are conducted periodically to incorporate current demographics of plan membership, and update applicable assumptions to represent the current best estimate based on plan experience and current expectations. The new comprehensive accounting valuation was triggered by the availability of more current information as a result of performing the January 1, 2016 funding valuation, and ensured that OPG's accounting obligations continued to be fairly stated in accordance with US GAAP.

³² Total OPG projected costs for 2017 can be found in EB-2016-0152 Ex. N1-1-1, Attachment 2, p. 5 and p. 17, with the corresponding amounts attributed to the nuclear facilities at EB-2016-0152 Ex. N1-1-1, p. 10, Chart 3.1.2.

³³ As in previous proceedings, expected net growth (i.e. change) in cost components refers to the impact of changes in current service costs in the normal course, higher interest costs on a higher benefit obligation due to the passage of time, expected changes in the pension asset value, and related changes in amortization of historical actuarial gains or losses.

Actual registered pension plan contributions and OPEB benefit payments for 2016 and 2017 are discussed under section 5.10 above. For 2014 and 2015, a similar discussion is found in EB-2016-0152, Ex. F4-3-2 section 4.2.

OPG's proposal with respect to the recovery of the December 31, 2017 balance in the account and implementation of the OEB's policy on pension and OPEB cost recovery is set out in Ex. F1-1-1.

5.12 Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in EB-2014-0369 and continued in EB-2016-0152. Effective November 1, 2014, this account records the difference between the annual revenue requirement impact of the Niagara Tunnel Project rate base addition disallowance of \$28.0M ordered in EB-2013-0321 Decision with Reasons and the varied disallowance of \$6.4M determined in EB-2014-0369. The 2017 payment amount for the regulated hydroelectric facilities approved in EB-2016-0152 reflected the EB-2013-0321 disallowance and did not reflect the impact of the varied disallowance.

The December 31, 2017 debit balance in the account is \$5.7M, comprising an annual revenue requirement impact of approximately \$1.8M for each of 2015, 2016 and 2017 and \$0.3M for November 1 to December 31, 2014, being 2/12 of the annual revenue requirement of approximately \$1.8M for 2014.³⁴ The derivation of these entries is shown in Ex. H1-1-1 Table 9. As the account was approved in 2016, the entries for 2014 and 2015 were calculated retrospectively and recorded in 2016, consistent with the EB-2014-0369 Decision and Order.

5.13 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account records the revenue requirement impact on the prescribed facilities of any change in OPG's

³⁴ The annual revenue requirement impact of \$1.8M is slightly lower than the \$2.1M estimated in the EB-2014-0369 Decision and Order at p.12.

1 nuclear decommissioning and used fuel and waste management liabilities (“nuclear liabilities”)
2 arising from an approved reference plan under the Ontario Nuclear Funds Agreement
3 (“ONFA”) measured against the forecast impact reflected in the revenue requirement approved
4 by the OEB. Pursuant to the EB-2013-0321 and EB-2014-0370 Payment Amounts Orders,
5 OPG was to record the return on rate base in the account using the weighted average accretion
6 rate on OPG’s nuclear liabilities of 5.37% prior to the effective date of the EB-2016-0152 PAO.
7 As of the effective date of the EB-2016-0152 PAO, OPG is to record the return on rate base in
8 the account using the weighted average accretion rate of 4.95%.

9
10 The debit entries of \$2.9M for 2016 and \$15.7M for 2017 relate to changes in the above
11 liabilities arising from the current approved 2017-2021 ONFA Reference Plan effective January
12 1, 2017, until the June 1, 2017 effective date of the EB-2016-0152 PAO.³⁵ The derivation of
13 these additions is shown at Ex. H1-1-1, Table 10. As the impact of the 2017-2021 ONFA
14 Reference Plan is reflected in the revenue requirement approved in EB-2016-0152, there are
15 no account additions for the June 1, 2017 to December 31, 2017 period.

16
17 The above entries for the prescribed facilities primarily relate to a decrease in asset retirement
18 costs (“ARC”) and an increase in ARC depreciation reflecting the year-end 2016 asset
19 retirement obligation (“ARO”) adjustment, and a decrease in income tax impacts reflecting
20 contributions to the ONFA segregated funds per the 2017 ONFA Contribution Schedule
21 approved by the Province of Ontario, relative to amounts underpinning the EB-2013-0321
22 nuclear payment amount. The changes in the nuclear liabilities costs reflecting the 2017-2021
23 ONFA Reference Plan were discussed in EB-2016-0152 at Ex. N1-1-1 (section 3.2), Ex. C2-
24 1-2 and Ex. J21.2.

25
26 No interest was recorded in the account in 2016 or 2017, pursuant to the corresponding
27 payment amounts orders.

³⁵ As anticipated in EB-2016-0152, Ex. N1-1-1, p. 16, footnote 13, the debit entry in 2016 relates to an asset retirement obligation increase recorded on December 31, 2016 in relation to changes in cost estimates related to the implementation of the 2012 Canadian Nuclear Safety Commission requirements to include certain facilities with Waste Nuclear Substance Licenses. These facilities were included for the first time in the 2017-2021 ONFA Reference Plan. In accordance with GAAP, this asset retirement obligation adjustment was expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility not used to support OPG’s current operations.

5.14 Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB.

During 2016 and 2017, OPG continued to incur costs to maintain the license granted by the Canadian Nuclear Safety Commission, which preserves the option of considering Nuclear New Build in the future. For January 1, 2016 through May 31, 2017, these costs were higher than the reference amount of \$0 that reflected the forecasts underpinning the revenue requirement approved in EB-2013-0321. For the remainder of 2017, these costs were lower than the reference amount that reflected the forecasts underpinning the revenue requirement approved in EB-2016-0152, due to lower than budgeted CNSC licencing fees.

The derivation of the resulting \$0.8M debit addition to the account in 2016 and \$0.6M credit addition in 2017 is shown in Ex. H1-1-1 Table 11.

5.15 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved in EB-2007-0905 in order to ensure that the actual difference between OPG's revenues and costs for the Bruce facilities is ultimately reflected in payment amounts and riders and that OPG recovers its actual costs associated with the Bruce facilities, and has been approved in all subsequent OPG applications.

This account records differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities.

1 The account has two sub-accounts described below:

2 Derivative Sub-Account: The Derivative Sub-Account balance relates to the previously existing
3 derivative liability for the conditional supplemental rent rebate provision of the Bruce lease
4 (including associated income tax impacts on Bruce lease net revenues calculated in
5 accordance with generally accepted accounting principles for unregulated entities) and the rent
6 rebates associated with supplemental rent revenue. As noted in the EB-2016-0152 PAO
7 (Appendix G, p. 16), pursuant to the 2015 amendment to the Bruce lease agreement, the
8 provision for a conditional supplemental rent rebate was removed effective December 4, 2015
9 and the derivative liability was eliminated.

10
11 The remaining credit balance largely represents the amount that the OEB had authorized to
12 be recovered through the EB-2014-0370 rate riders, prior to the 2015 amendment to the Bruce
13 lease agreement, and which therefore must be refunded to ratepayers. Amortization of the
14 resulting credit balance of \$68.6M as at December 31, 2015 was approved for refund to
15 customers in EB-2016-0152. No additions were recorded in the sub-account during 2016 or
16 2017. An interest credit of \$0.8M was recorded during 2017, which OPG proposes to clear as
17 part of this Application.³⁶ Amortization and interest recorded in the sub-account during 2016
18 and 2017, as applicable, are shown in Ex. H1-1-1 Table 1b, line 20.

19
20 Non-Derivative Sub-Account: The Non-Derivative Sub-Account balance relates to the non-
21 derivative aspects of the account, including the cost impact of any changes in OPG's liability
22 for decommissioning the Bruce facilities and the management of nuclear waste and nuclear
23 fuel related to the Bruce facilities.

24
25 Variances recorded in the non-derivative sub-account are determined by comparing the rate
26 of recovery for Bruce revenues net of costs reflected in the corresponding payment amounts
27 order multiplied by OPG's actual nuclear production, and OPG's actual Bruce revenues net of
28 costs. A rate of recovery of \$0.84/MWh was used to calculate sub-account entries for January
29 1, 2016 through May 31, 2017 and (\$0.137/MWh) for June 1, 2017 to December 31, 2017. The

³⁶ No interest was recorded during 2016 pursuant to the EB-2014-0370 payment amounts order (Appendix B, p. 13).

1 derivation of the 2016 debit entry of \$143.0M to the Non-Derivative Sub-Account and the 2017
2 debit entry of \$23.3M is shown in Ex. H1-1-1 Table 12.³⁷ A comparison of Bruce revenues net
3 of costs is presented in Ex. H1-1-1 Table 12a.

4
5 Bruce revenues net of costs for January 1, 2016 through May 31, 2017 were lower than the
6 forecasts underpinning the nuclear revenue requirement approved in EB-2013-0321, primarily
7 due to the impact on OPG's nuclear ARO and related ARC of extending the end-of-life ("EOL")
8 dates of the Bruce units, effective December 31, 2015, in line with the updated contract
9 between the Independent Electricity System Operator and Bruce Power L.P. to enable the
10 refurbishment of Bruce Units 3-8. As discussed in EB-2016-0152 Ex. C2-1-1 and Ex. G2-2-1,
11 the extension of the EOL dates was reflected in the year-end 2015 adjustments to the ARO
12 and ARC balances recorded by OPG in accordance with US GAAP, which was the primary
13 driver for the increase in accretion expense on the nuclear liabilities. Bruce revenues net of
14 costs were also lower than the EB-2013-0321 forecasts due to changes in the supplemental
15 rent revenue under the amended lease agreement executed between OPG and Bruce Power
16 in December 2015 in support of the planned Bruce unit refurbishments. As discussed in EB-
17 2016-0152 Ex. G2-2-1, the amended lease agreement aligned the supplemental rent with the
18 prevailing ONFA-based estimate of OPG's lifecycle costs of managing Bruce Power's used
19 fuel generated over the remaining term of the lease.

20
21 Bruce revenues net of costs for June 1, 2017 through December 31, 2017 were lower than the
22 forecast underpinning the nuclear revenue requirement approved in EB-2016-0152, with a
23 higher amount of interest expense allocated to the Bruce assets as the largest driver. The
24 higher interest expense was mainly due to a higher than budgeted allocation factor, reflecting
25 the increase in the ratio of the net book value of the Bruce fixed assets relative to OPG's total
26 fixed assets from the ARC adjustment recorded at the end of 2015.

27

³⁷ For January 1, 2016 through May 31, 2017, as per the EB-2014-0370 Payment Amounts Order, adjustments were made to ensure that amounts recorded in the account did not include those that OPG indicated in EB-2013-0321 it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence in EB-2013-0321 dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts were outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

No interest was recorded in the sub-account in 2016 pursuant to the EB-2014-0370 Payment Amounts Order.

5.16 Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the difference between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on actual nuclear production and approved riders. The account also captures the transfer of the nuclear portions of the balances remaining in other accounts as they expire from time to time.

The derivation of the \$29.0M debit entry to the account for 2016 is shown in Ex. H1-1-1 Table 13. Since there were no riders effective in 2017, no additions in 2017. There were no transfers in 2016 or 2017.

5.17 Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account

The Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account was approved in EB-2015-0374. Effective January 1, 2016, this account records the revenue requirement impact arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station EOL dates for Bruce, Pickering and Darlington nuclear generating stations that became effective December 31, 2015.³⁸

Pursuant to the EB-2015-0374 Payment Amounts Order and the EB-2016-0152 PAO, account additions were recorded for January 1, 2016 through May 31, 2017 only, as the impact arising from changes to station EOL dates was reflected in the revenue requirement approved in EB-2016-0152.

³⁸ The account records the revenue requirement impact on the prescribed facilities, as the impact on the Bruce facilities is captured in the Bruce Lease Net Revenues Variance Account discussed in section 5.15.

1 Derivation of the \$71.2M credit entry in 2016 and \$32.1M credit entry in 2017 is shown in Ex.
2 H1-1-1 Table 14, line 19. As shown in the Table, these entries comprise revenue requirement
3 impact arising from changes to nuclear liabilities of \$65.5M for 2016 and \$29.8M for 2017 and
4 from change to non-ARC depreciation and amortization expense of \$5.8M for 2016 and \$2.4M
5 for 2017. The projected nuclear liabilities' impact for 2016 was described in EB-2016-0152, Ex.
6 C2-1-1, section 5.0 and is essentially the same as the actual impact recorded in the account.³⁹
7 As discussed in that evidence, the nuclear liabilities' impact reflects the December 31, 2015
8 reduction in the ARC balance and the associated decrease in ARC depreciation and was
9 derived using the same methodologies as applied in previous proceedings.⁴⁰ As set out in the
10 EB-2015-0374 Decision and Order (Appendix A), the non-ARC depreciation expense impact
11 was based on December 31, 2015 fixed asset balances.

12
13 No interest was recorded in the account in 2016 or 2017 pursuant to the corresponding orders
14 of the OEB.

15 16 **5.18 SR&ED ITC Variance Account**

17 The SR&ED ITC Variance Account was approved in EB-2016-0152, as of the effective date of
18 the EB-2016-0152 PAO. The account records the difference between actual SR&ED ITCs
19 (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED
20 ITCs included in the nuclear revenue requirement approved by the OEB, including the tax on
21 the difference.

22
23 Actual SR&ED ITCs net of tax (attributed to the nuclear facilities) recorded in 2017 were higher
24 than the reference amount that reflected the forecast underpinning the 2017 revenue
25 requirement approved in EB-2016-0152. The derivation of the resulting credit entry of \$3.4M
26 for 2017 is shown in Ex. H1-1-1 Table 15.

³⁹ EB-2016-0152, Ex. C2-1-1, Table 6, line 8, col. (c) projected a credit entry of \$65.3M for 2016, compared to the actual entry of \$65.5M.

⁴⁰ As noted in EB-2016-0152, Ex. C2-1-1, section 5.0, the nuclear liabilities' impact includes the reduction in depreciation expense for ARC balances recorded prior to December 31, 2015 as a result of the extensions in the estimated service lives of the Pickering and Darlington stations.

5.19 Fitness for Duty Deferral Account

The Fitness for Duty Deferral Account was approved in EB-2016-0152, as of the effective date of the EB-2016-0152 PAO. The account records costs related to implementing the Canadian Nuclear Safety Commission (“CNSC”) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, anticipated to be a license requirement of the CNSC.

The Fitness for Duty requirements were approved by the CNSC in 2017 and OPG has begun the process to implement the necessary programmatic changes to comply with the new requirements. The account entries for June 1, 2017 to December 31, 2017 comprise initial costs incurred totaling \$0.1M. Given the relatively early stage of the implementation work, this Application is not seeking clearance of the amount in the account. OPG proposes to defer the clearance to a future application, which would allow an assessment of the costs to be undertaken at a time when implementation has advanced.

5.20 Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account was established in accordance with section 5.5 of O. Reg. 53/05 and approved in EB-2016-0152. The account records the difference between: (i) the total annual nuclear revenue requirement approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the nuclear payment amounts in each year (“the annual deferral amount”).

The account was effective as of January 1, 2017. Pursuant to the EB-2016-0152 PAO, no additions are to be recorded to the account for 2017 and, therefore, the December 31, 2017 balance is \$0.⁴¹

⁴¹ An amount of \$63M was initially credited to the Rate Smoothing Deferral Account in 2017, based upon the rate smoothing proposal presented in OPG’s Draft Payment Amounts Order filed in January 2018. This amount was subsequently reversed as the OEB’s decision on the EB-2016-0152 PAO ordered no amounts be deferred in the account for 2017.

ATTACHMENTS

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- Attachment 1: Schedule of Regulatory Balances as at December 31,
- Attachment 2: 2017 Independent Auditors' Report prepared by Ernst & Young LLP
Chartered Professional Accountants
- Attachment 3: Aon Hewitt Report on OPG's Pension and OPEB Costs for 2016 and
2017
- Attachment 4: Aon Hewitt Report on OPG's Pension and OPEB Costs for 2014
and 2015, as provided in EB-2016-0152, Ex. F4-3-1, Attachment 2

**SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2017**

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. (OPG or the Company) receives regulated prices for electricity generated from most of the Company's hydroelectric generating facilities and all of the nuclear generating facilities that the Company operates. OPG's regulated prices for the generation from these facilities are determined by the Ontario Energy Board (OEB).

The OEB's decisions and orders have authorized OPG to establish certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The balances in these accounts are calculated in accordance with the OEB's decisions and orders and *Ontario Regulation 53/05*. In accordance with United States generally accepted accounting principles ("US GAAP"), OPG's consolidated financial statements recognize regulatory assets and regulatory liabilities for balances in the variance and deferral accounts.

Through its March 2018 and December 2017 decisions on OPG's application for new regulated prices under case number EB-2016-0152 and related partial settlement agreement between OPG and intervenors, the OEB approved the balances in all of the Company's variance and deferral account balances as at December 31, 2015, with the exception of the Pension & OPEB Cash to Accrual Differential Deferral Account and less amounts previously approved for recovery or repayment in these accounts during 2016 under case number EB-2014-0370. To effect recovery of the balances approved in the EB-2016-0152 proceeding, the OEB established rate riders for OPG's regulated generation for the period from March 1, 2018 to December 31, 2020.

For the period from January 1, 2016 to May 31, 2017, OPG recorded additions to the variance and deferral accounts and amortized the balances in the accounts as authorized by the OEB in the EB-2014-0370 Payment Amounts Order. For the period from June 1, 2017 to December 31, 2017, OPG recognized additions to the variance and deferral accounts and amortized the balances in the accounts as authorized by the OEB in the EB-2016-0152 Payment Amounts Order. Where authorized by the OEB, OPG recorded interest on the unamortized balances in the applicable variance and deferral accounts at the OEB-prescribed rate of 1.10 percent per annum during the period from January 1, 2016 to September 30, 2017 and 1.50 percent per annum during the period from October 1, 2017 to December 31, 2017.

As at December 31, 2017, the balances to be recovered from (refunded to) ratepayers in the variance and deferral accounts authorized for OPG were as follows:

<i>(millions of dollars)</i>	2017
Regulated Hydroelectric	
Hydroelectric Surplus Baseload Generation Variance Account	360
Capacity Refurbishment Variance Account – Hydroelectric	9
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric	84
Pension and OPEB Cost Variance Account – Hydroelectric – Post 2012 Additions	27
Pension and OPEB Cost Variance Account – Hydroelectric – Future Recovery	8
Pension & OPEB Cash Payment Variance Account – Hydroelectric	(26)
Ancillary Services Net Revenue Variance Account – Hydroelectric	(45)
Hydroelectric Water Conditions Variance Account	(150)
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	25
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	6
Hydroelectric Incentive Mechanism Variance Account ¹	-
Income and Other Taxes Variance Account – Hydroelectric ¹	-
Gross Revenue Charge Variance Account	-
Total – Regulated Hydroelectric	298
Nuclear	
Pension and OPEB Cost Variance Account – Nuclear – Future Recovery	172
Pension and OPEB Cost Variance Account – Nuclear – Post 2012 Additions	509
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear	530
Pension & OPEB Cash Payment Variance Account – Nuclear	(114)
Nuclear Liability Deferral Account	18
Bruce Lease Net Revenues Variance Account – Derivative Sub-Account	(69)
Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account	189
Nuclear Deferral and Variance Over/Under Recovery Variance Account	75
Capacity Refurbishment Variance Account – Nuclear – Non-Capital Portion	(58)
Capacity Refurbishment Variance Account – Nuclear – Capital Portion	(28)
Income and Other Taxes Variance Account – Nuclear	(10)
Nuclear Development Variance Account	2
Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	(103)
Rate Smoothing Deferral Account (<i>Note 2</i>)	-
Ancillary Services Net Revenue Variance Account – Nuclear	3
SR&ED ITC Variance Account	(3)
Fitness for Duty Deferral Account ¹	-
Total – Nuclear	1,113

¹The account balance is less than \$0.5 million, which rounds to nil million.

This schedule of regulatory balances has been prepared solely for the use of OPG's management and for filing with the OEB, and is considered by OPG's management to be a fair and reasonable representation of the balances in the authorized variance and deferral accounts as at December 31, 2017. These balances have been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.

[Original signed by]

Ken Hartwick

Chief Financial Officer and Senior Vice President – Finance

August 9, 2018

See accompanying notes to the schedule

**NOTES TO THE SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2017**

1. BASIS OF ACCOUNTING

The schedule of regulatory balances presents the balances as at December 31, 2017 in all variance and deferral accounts authorized for OPG. These balances represent the regulatory assets and regulatory liabilities for these accounts recorded by OPG in accordance with US GAAP for the purposes of its consolidated financial statements, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers and to include the full amount of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017. All dollar amounts are presented in Canadian dollars.

For the purposes of its consolidated financial statements prepared in accordance with US GAAP, as required by FASB Accounting Standards Codification Topic 980, *Regulated Operations*, OPG limits the portion of cost of capital additions recognized as a regulatory asset to the amount calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances. The amortization expense related to the regulatory assets for variance and deferral accounts that include cost of capital additions are correspondingly limited in OPG's consolidated financial statements to amounts calculated using the average rate of capitalized interest applied to OPG's construction and development in progress balances.

In the EB-2016-0152 payment amounts order issued on March 23, 2018, the OEB stipulated that OPG will be entitled to future recovery of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 to the extent that OPG's total capital in-service additions for the regulated hydroelectric facilities over the 2017-2021 period exceed the funding for capital expenditures for these facilities implicit in the hydroelectric payment amounts over that period, as calculated pursuant to the EB-2016-0152 payment amounts order. In accordance with US GAAP, OPG's consolidated financial statements do not recognize a regulatory asset for additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 until such time as OPG assesses that there is sufficient assurance that these amounts will be recoverable in the future based on the above condition.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that incurred costs in respect of its regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in the Company's consolidated financial statements. When OPG is required to refund amounts in respect of its regulated facilities to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability in its consolidated financial statements. The measurement of regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

OPG's most recent annual consolidated financial statements filed with the Ontario Securities Commission are as at and for the year ended December 31, 2017. OPG's most recent interim consolidated financial statements filed with the Ontario Securities Commission are as at and for the six months ended June 30, 2018.

2. RATE SMOOTHING DEFERRAL ACCOUNT

The Rate Smoothing Deferral Account was established by the OEB in the EB-2016-0152 proceeding pursuant to *Ontario Regulation 53/05* to record, for future recovery, a portion of the annual OEB-approved revenue requirement for OPG's nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project, in order to make more stable changes in OPG's production-weighted average nuclear and hydroelectric regulated price year over year. In January 2018, OPG submitted a draft payment amounts order to the OEB to reflect the findings in the OEB's December 2017 decision in the EB-2016-0152 proceeding, including a rate smoothing proposal to implement the above *Ontario Regulation 53/05* requirements. This proposal was the basis for a regulatory liability of \$63 million

for the Rate Smoothing Deferral Account recorded as management's best estimate in OPG's 2017 annual consolidated financial statements. The EB-2016-0152 payment amounts order issued by the OEB subsequent to the issuance of OPG's 2017 annual consolidated financial statements set a rate smoothing approach such that no amounts are to be deferred in the Rate Smoothing Deferral Account until 2019. To reflect this direction, OPG reversed the \$63 million regulatory liability for the Rate Smoothing Deferral Account in its 2018 first quarter interim consolidated financial statements. The schedule of regulatory balances reflects the EB-2016-0152 payment amounts order and therefore includes a balance of nil for the Rate Smoothing Deferral Account as at December 31, 2017.

INDEPENDENT AUDITORS' REPORT

To the management of
Ontario Power Generation Inc.

We have audited the accompanying schedule of regulatory balances of **Ontario Power Generation Inc.** as at December 31, 2017 (the "Schedule"). The Schedule has been prepared by management to present the balances of the variance and deferral accounts authorized for Ontario Power Generation Inc. by the decisions and orders of the Ontario Energy Board, in accordance with the basis of accounting as described in Note 1 to the Schedule.

Management's responsibility for the schedule

Management is responsible for the preparation of this Schedule in accordance with the basis of accounting as described in Note 1 to the Schedule and for such internal control as management determines is necessary to enable the preparation of the Schedule that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on the Schedule based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Schedule is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Schedule. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation of the Schedule in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Schedule.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Schedule presents, in all material respects, the balances of the variance and deferral accounts authorized for **Ontario Power Generation Inc.** as at December 31, 2017 by the decisions and orders of the Ontario Energy Board, in accordance with the basis of accounting as described in Note 1 to the Schedule.

Basis of accounting and restriction on distribution

Without modifying our opinion, we draw attention to Note 1 to the Schedule, which describes the basis of accounting. The Schedule is prepared solely for the use of **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process. As a result, the Schedule may not be suitable for another purpose.



– 2 –

Our auditors' report is intended solely for **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process and should not be used for any other purpose.

Toronto, Canada
August 9, 2018

[Original Signed by]

ERNST & YOUNG LLP
Chartered Professional Accountants
Licensed Public Accountants



A member firm of Ernst & Young Global Limited



Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2016 and 2017

Ontario Power Generation Inc.
January 1, 2016 to December 31, 2017



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Introduction

This report summarizes the accounting costs for fiscal years 2016 and 2017 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the December 31, 2017 balances in OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account established by the Ontario Energy Board ("OEB"). We understand that this report is expected to be filed with the OEB.

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP");
- Non-Pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, retiree dental, retiree life insurance, and retirement bonus benefits, and
- Post Employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal years from January 1, 2016 to December 31, 2016 and from January 1, 2017 to December 31, 2017. The results have been developed in accordance with US generally accepted accounting principles ("US GAAP") under ASC 710, 712 and 715.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG's consolidated financial statements.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2016 or the December 31, 2017 disclosure reports ("the Reports") prepared by Aon in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2017 and March 2018, respectively, and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

August 2018

Aon

[Original signed by]

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Actuarial Report

Results for 2016 and 2017

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2016 to December 31, 2017, as determined in accordance with US GAAP, are as follows:

(in Canadian \$ 000's)	January 1 to December 31, 2016	January 1 to May 31, 2017	June 1 to December 31, 2017	Total for January 1 to December 31, 2017
RPP	\$ 367,277	\$ 99,048	\$ 138,666	\$ 237,714
SPP	22,112	9,862	13,807	23,669
OPRB	199,546	65,350	91,490	156,840
LTD	<u>(32,699)</u>	<u>7,193</u>	<u>19,650</u>	<u>26,843</u>
Total	\$ 556,236	\$ 181,453	\$ 263,613	\$ 445,066

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2016 to December 31, 2017 are provided in Schedules 1 and 2 to this report.

In its November 2014 decision under case number EB-2013-0321, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account for OPG's nuclear and regulated hydroelectric businesses, effective November 1, 2014. The OEB authorized the continuation of these accounts in its December 2017 decision under case number EB-2016-0152, effective June 1, 2017.

As shown in materials filed by OPG under OEB case number EB-2016-0152, additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the portion of the November 1, 2014 to December 31, 2015 OPG-wide US GAAP pension and OPEB costs attributed to OPG's nuclear and regulated hydroelectric businesses to the regulated businesses' portion of OPG's total actual contribution to the RPP fund and actual benefit payments under OPEB plans for the corresponding periods. As also shown in those materials, additions to the Pension & OPEB Cash Payment Variance Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the regulated businesses' portion of the total actual contribution to the RPP fund and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2013-0321. We previously reported on OPG's total actual pension and OPEB costs, contributions to the RPP fund and benefit payments under OPEB plans for the periods from November 1, 2014 to December 31, 2015 in the following report in support of the balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account as at December 31, 2015, which was filed by OPG with the OEB under case number EB-2016-0152:

- “Report on the Accounting Cost for Post Employment Benefit Plans For Fiscal Years 2014 and 2015” dated May 2016.

As shown in materials OPG expects to file under OEB case number EB-2018-0243, additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from January 1, 2016 to December 31, 2017 were calculated by OPG by comparing the portion of the January 1, 2016 to December 31, 2017 OPG-wide US GAAP pension and OPEB costs attributed to OPG’s nuclear and regulated hydroelectric businesses to the regulated businesses’ portion of OPG’s total actual contribution to the RPP fund and actual benefit payments under OPEB plans for the corresponding periods. As also shown in those materials, additions to the Pension & OPEB Cash Payment Variance Account for the period from January 1, 2016 to May 31, 2017 were calculated by OPG by comparing the regulated businesses’ portion of the total actual contribution to the RPP fund and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2013-0321. Similarly, for the period from June 1, 2017 to December 31, 2017, additions to the Pension & OPEB Cash Payment Variance Account were calculated by OPG by comparing the regulated businesses’ portion of the total actual contribution to the RPP fund and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2016-0152.

The resulting balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account calculated and recorded by OPG as at December 31, 2017 were \$614 million to be recovered from ratepayers and \$140 million to be paid to ratepayers, respectively, as reported in the audited schedule of regulatory balances as at December 31, 2017, prepared by OPG for filing with the OEB and dated August 9, 2018.

Actuarial Methods and Assumptions

Aon confirms that the OPG-wide costs for the years ended December 31, 2016 and December 31, 2017 as disclosed in this report were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG’s application to the OEB under case number EB-2016-0152 and used to determine the forecast of OPG-wide pension and OPEB costs for 2017, which were presented by OPG in that proceeding through the filing of our report on these costs, “Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2017 to 2021” dated December 2016.

We also confirm that, other than the prospective adoption of the full yield curve approach effective January 1, 2017 discussed below, the methodology under US GAAP is consistent with the methodology outlined in OPG’s application to the OEB under case number EB-2013-0321 and used to determine the forecast OPG-wide pension and OPEB costs for 2014-2015, which were presented by OPG in that proceeding through the filing of our report on these costs, “Update to Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2014 to 2015” dated March 2014. The adoption of the full yield curve approach had the effect of reducing OPG’s pension and OPEB costs for 2017.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;

- The discount rates have been determined in accordance with US GAAP, with reference to a yield curve representative of AA corporate bonds in Canada.

Prior to January 1, 2017, the current service cost and interest cost for OPG's pension and OPEB plans were determined using the single equivalent discount rate approach. Under that method, a single weighted average discount rate is set by reference to a yield curve reflecting the projected cash flow stream of the plans, and this discount rate is used to determine the benefit obligation and cost components such as current service cost and interest cost, in accordance with US GAAP. The discount rates for determining the 2016 costs were 4.10% per annum for RPP and SPP, 4.20% per annum for OPRB, and 3.10% per annum for LTD.

Effective January 1, 2017, OPG adopted the full yield curve approach to measure these costs, on a prospective basis, in accordance with US GAAP as a change in accounting estimate. The full yield curve approach provides a more precise measurement of current service cost and interest cost components which improves the allocation of the net periodic pension benefit costs to the appropriate reporting periods.

Under the full yield curve approach, individual spot discount rates along the yield curve are applied to the projected cash flows at the relevant maturity, resulting in a more precise interest cost. The service cost is more precisely determined based on duration specific spot rates applied to discount the service cost projected cash flows.

The effective discount rates for determining the 2017 pension and OPEB costs under the full yield curve approach¹ were as follows:

	RPP and SPP	OPRB	LTD
Current Service Cost	4.15% per annum	4.21% per annum	3.10% per annum
Interest Cost ²	3.37% per annum	3.58% per annum	2.46% per annum

The discount rate used to determine the projected benefit obligation for LTD at the end of 2017 was 3.09%.

- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon calculated the expected return based on this methodology. An expected rate of return on assets of 6.00% per annum determined using the above approach was used for determining the 2016 and 2017 RPP costs;

¹ A series of individual spot rates applied to projected cash flows under the full yield curve approach is expressed as a single effective discount rate for disclosure purposes.

² The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2017, this rate was 3.95% for RPP and SPP costs, 4.13% for OPRB costs and 2.46% for LTD costs.

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. For 2016 and 2017 costs, the inflation rate was set at 2.00% per annum, and the salary scale increase rate, which was established at 1.00% per annum to December 31, 2017 for the Power Workers Union ("PWU") represented employees and to December 31, 2018 for employees represented by the Society of United Professionals ("Society"), followed by 2.00% per annum up to December 31, 2021, and 2.50% per annum thereafter (plus Promotion, Progression, Merit in all years). These salary scale increase assumptions for the 2016-2017 period for PWU-represented employees and for the 2016-2018 period for employees represented by the Society are consistent with the provisions of the corresponding collective agreements;
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2016 and 2017);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2016 and 2017);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.00% per annum plus the increase in Consumer Price Index are smoothed over five years.

For 2016, OPG's contributions to the RPP fund were made pursuant to the filed actuarial valuation report for funding purposes as of January 1, 2016 of the RPP. For 2017, OPG's contributions to the RPP fund were made pursuant to the filed actuarial valuation report for funding purposes as of January 1, 2017 of the RPP.

Schedule 1—Summary of 2016 US GAAP Results

The following table provides a summary of US GAAP results for 2016 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2016.

(in Canadian \$ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2016				
Projected Benefit Obligation	\$ (15,404,062)	\$ (295,295)	\$ (2,914,927)	\$ (259,900)
Fair Value of Plan Assets	<u>13,072,299</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Asset (Liability) Recognized	\$ (2,331,763)	\$ (295,295)	\$ (2,914,927)	\$ (259,900)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2016				
Unrecognized Past Service Costs (Credits)	\$ -	\$ -	\$ 5,851	\$ -
Unrecognized Net Actuarial Loss (Gain)	<u>3,017,663</u>	<u>77,532</u>	<u>537,802</u>	<u>-</u>
Total Accumulated Other Comprehensive Loss (Income)	\$ 3,017,663	\$ 77,532	\$ 543,653	\$ -
Components of Net Periodic Pension/Benefit Cost, January 1, 2016 to December 31, 2016				
Employer Current Service Cost	\$ 273,247	\$ 6,092	\$ 56,497	\$ 9,647
Interest Cost	630,810	11,986	123,223	8,701
Expected Return on Plan Assets	(728,898)	-	-	-
Recognition of LTD Actuarial (Gain) Loss	-	-	-	(51,047)
Amortization of Past Service Cost (Credit)	-	-	583	-
Amortization of Net Actuarial Loss (Gain)	<u>192,118</u>	<u>4,034</u>	<u>19,243</u>	<u>-</u>
Total Cost	\$ 367,277	\$ 22,112	\$ 199,546	\$ (32,699)
2016 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit costs	\$ 353,316	\$ 18,107	\$ 75,094	\$ 27,280
2016 Actual Employer Pension Contributions / Benefit Payments	\$ 253,083	\$ 15,015	\$ 66,557	\$ 25,456

Schedule 2—Summary of 2017 US GAAP Results

The following table provides a summary of US GAAP results for 2017 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2017.

(in Canadian \$ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2017				
Projected Benefit Obligation	\$ (16,117,967)	\$ (331,583)	\$ (2,775,480)	\$ (201,745)
Fair Value of Plan Assets	<u>13,410,405</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Asset (Liability) Recognized	\$ (2,707,562)	\$ (331,583)	\$ (2,775,480)	\$ (201,745)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2017				
Unrecognized Past Service Costs (Credits)	\$ -	\$ -	\$ 5,268	\$ -
Unrecognized Net Actuarial Loss (Gain)	<u>3,279,268</u>	<u>106,723</u>	<u>265,949</u>	<u>-</u>
Total Accumulated Other Comprehensive Loss (Income)	\$ 3,279,268	\$ 106,723	\$ 271,217	\$ -
Components of Net Periodic Pension/Benefit Cost, January 1, 2017 to December 31, 2017				
Employer Current Service Cost	\$ 270,206	\$ 6,504	\$ 55,790	\$ 11,096
Interest Cost	544,063	11,135	100,467	4,894
Expected Return on Plan Assets	(759,922)	-	-	-
Recognition of LTD Actuarial (Gain) Loss	-	-	-	10,853
Amortization of Past Service Cost (Credit)	-	-	583	-
Amortization of Net Actuarial Loss (Gain)	<u>183,367</u>	<u>6,030</u>	<u>-</u>	<u>-</u>
Total Cost	\$ 237,714	\$ 23,669	\$ 156,840	\$ 26,843
2017 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit cost	\$ 247,710	\$ 17,610	\$ 67,017	\$ 27,764
2017 Actual Employer Pension Contributions / Benefit Payments				
Annual	\$ 211,736	\$ 13,706	\$ 68,307	\$ 26,278
January to May ¹	\$ 105,000	\$ 5,611	\$ 27,449	\$ 9,294
June to December	\$ 106,736	\$ 8,095	\$ 40,858	\$ 16,984

¹ Actual SPP, OPRB and LTD payments for the period as provided by OPG

About Aon

Aon plc (NYSE:AON) is a leading global professional services firm providing a broad range of risk, retirement and health solutions. Our 50,000 colleagues in 120 countries empower results for clients by using proprietary data and analytics to deliver insights that reduce volatility and improve performance.

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Ontario Power Generation Inc.
January 1, 2014 to December 31, 2015

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Introduction

This report summarizes the accounting costs for fiscal years 2014 and 2015 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon Hewitt prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the December 31, 2015 balances in OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account established by the Ontario Energy Board ("OEB"). We understand that this report is expected to be filed with the OEB.

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP");
- Non-pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post Employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal years from January 1, 2014 to December 31, 2014 and from January 1, 2015 to December 31, 2015. The results have been developed in accordance with US generally accepted accounting principles ("US GAAP") under ASC 715, 712 and 710.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG's consolidated financial statements.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2014 or the December 31, 2015 disclosure reports ("the Reports") prepared by Aon Hewitt in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated February 2015 and March 2016, respectively, and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Aon Hewitt

Sincerely,

Aon Hewitt Inc.

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

May 2016

Aon Hewitt Inc.

[Original signed by]

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Actuarial Report

Results for 2014 and 2015

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2014 to December 31, 2015, as determined in accordance with US GAAP, are as follows:

(in Canadian \$ 000's)	January 1 to October 31, 2014	November 1 to December 31, 2014	Total for January 1 to December 31, 2014	January 1 to December 31, 2015
RPP	\$ 439,303	\$ 87,861	\$ 527,164	\$ 523,447
SPP	21,532	4,306	25,838	25,332
OPRB	150,546	30,109	180,655	206,799
LTD	<u>18,670</u>	<u>444</u>	<u>19,114</u>	<u>24,096</u>
Total	\$ 630,051	\$ 122,720	\$ 752,771	\$ 779,674

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2014 to December 31, 2015 are provided in Schedules 1 and 2 to this report.

The above pension and OPRB costs for the period January 1 to October 31, 2014 are the same as those previously reported by us in the following report in support of the balance in OPG's Pension and OPEB Cost Variance Account established by the OEB, which was filed by OPG with the OEB under case number EB-2014-0370:

- "Report on the Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Account Calculations – Fiscal Year 2013 and the Period from January 1 to October 31, 2014" dated February 2015.

Up to October 31, 2014, the Pension and OPEB Cost Variance Account recorded the difference between actual pension and OPEB costs under Canadian GAAP for OPG's regulated operations and related tax impacts, and those reflected in the regulated prices established by the OEB under case number EB-2010-0008.

In its November 2014 decision under case number EB-2013-0321, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account for OPG's nuclear and regulated hydroelectric businesses, effective November 1, 2014. Additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the portion of the above November 1, 2014 to December 31, 2015 OPG-wide US GAAP costs attributed to OPG's nuclear and regulated hydroelectric businesses to the regulated businesses' portion of OPG's total actual contribution to the RPP fund and actual benefit payments under OPEB plans for the corresponding periods, (which are found in Schedules 1 and 2

to this report). Additions to the Pension & OPEB Cash Payment Variance Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the regulated businesses' portion of the actual contribution to the RPP fund and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2013-0321.

The balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account calculated and recorded by OPG as at December 31, 2015 are \$315 million and \$28 million to be recovered from ratepayers, respectively, as reported in the audited schedule of regulatory balances as at December 31, 2015, prepared by OPG for filing with the OEB, and dated April 7, 2016.

Actuarial Methods and Assumptions

Aon Hewitt confirms that the OPG-wide costs for the years ended December 31, 2014 (including specifically the period from November 1, 2014 to December 31, 2014) and December 31, 2015 were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG's application to the OEB under case number EB-2013-0321 and used to determine the forecast of OPG-wide pension and OPEB costs for the 2014-2015 period, which were presented by OPG in that proceeding through the filing of our report on these costs dated March 2014 and titled "Update to Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2014 to 2015".

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP. The discount rates have been set with reference to those representative of AA corporate bond yields in Canada having a duration similar to the liabilities of the plans. The discount rates for determining the 2014 costs (including the period from November 1, 2014 to December 31, 2014) were 4.90% per annum for RPP and SPP, 5.00% per annum for OPRB, and 3.30% per annum for LTD. The discount rates for determining the 2015 costs were 4.00% per annum for RPP and SPP, 4.10% per annum for OPRB, and 3.40% per annum for LTD.
- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon Hewitt calculated the expected return based on this methodology. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the 2014 and 2015 RPP costs;
- The best estimate assumptions for base mortality rates reflect OPG's actual experience derived from OPG's historical pensioner data. Starting with 2014 costs, the assumed mortality improvement rates were updated to reflect the improvement scale (CPM-B) developed by the Canadian Institute of Actuaries ("CIA") and published in the February 2014 CIA Final Report: Canadian Pensioners' Mortality;

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 2.50% per annum (plus Promotion, Progression, Merit), respectively, in determining the 2014 costs. For 2015 costs, the inflation rate was set at 2.00%, and the salary scale increase rate was set at 2.00% per annum for the first six years and 2.50% per annum thereafter (plus Promotion, Progression, Merit in all years);
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2014 and 2015);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2014 and 2015);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years.

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Schedule 1—Summary of 2014 US GAAP Results

The following table provides a summary of US GAAP results for 2014 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2014.

(in Canadian \$ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2014				
Projected Benefit Obligation	\$ (13,368,826)	\$ (285,169)	\$ (2,439,305)	\$ (267,830)
Fair Value of Plan Assets	10,893,428	0	0	0
Net Asset (Liability) Recognized	\$ (2,475,398)	\$ (285,169)	\$ (2,439,305)	\$ (267,830)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2014				
Unrecognized Past Service Costs (Credits)	0	0	950	0
Unrecognized Net Actuarial Loss (Gain)	3,492,617	78,721	319,518	0
Total Accumulated Other Comprehensive Loss (Income)	\$ 3,492,617	\$ 78,721	\$ 320,468	\$ 0
Components of Net Periodic Pension/Benefit Cost, January 1, 2014 to December 31, 2014				
Employer Current Service Cost	\$ 235,496	\$ 7,437	\$ 51,620	\$ 11,517
Interest Cost	655,696	14,110	122,963	10,887
Expected Return on Plan Assets	(624,026)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	(3,290)
Amortization of Past Service Cost (Credit)	0	0	120	0
Amortization of Net (Gain) Loss	259,998	4,291	5,952	0
Total Cost (Annual)	\$ 527,164	\$ 25,838	\$ 180,655	\$ 19,114
Total Cost (January to October)	\$ 439,303	\$ 21,532	\$ 150,546	\$ 18,670
Total Cost (November to December)	\$ 87,861	\$ 4,306	\$ 30,109	\$ 444
2014 Estimated Employer Pension Contributions / Benefit Payments				
Annual amounts used for developing net periodic pension/benefit costs	\$ 400,000	\$ 9,278	\$ 63,336	\$ 27,644
2014 Actual Employer Pension Contributions / Benefit Payments				
Annual	\$ 360,000	\$ 15,690	\$ 66,456	\$ 26,317
January to October	300,000	12,804	53,788	18,355
November to December	60,000	2,886	12,668	7,962

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Schedule 2—Summary of 2015 US GAAP Results

The following table provides a summary of US GAAP results for 2015 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2015.

(in Canadian \$ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2015				
Projected Benefit Obligation	\$ (15,601,615)	\$ (313,377)	\$ (2,866,895)	\$ (260,627)
Fair Value of Plan Assets	<u>12,328,171</u>	<u>0</u>	<u>0</u>	<u>0</u>
Net Asset (Liability) Recognized	\$ (3,273,444)	\$ (313,377)	\$ (2,866,895)	\$ (260,627)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2015				
Unrecognized Past Service Costs (Credits)	0	0	830	0
Unrecognized Net Actuarial Loss (Gain)	<u>4,123,499</u>	<u>96,781</u>	<u>633,029</u>	<u>0</u>
Total Accumulated Other Comprehensive Loss (Income)	\$ 4,123,499	\$ 96,781	\$ 633,859	\$ 0
Components of Net Periodic Pension/Benefit Cost, January 1, 2015 to December 31, 2015				
Employer Current Service Cost	\$ 316,533	\$ 7,158	\$ 60,943	\$ 8,601
Interest Cost	626,909	12,628	118,678	8,450
Expected Return on Plan Assets	(711,656)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	7,045
Amortization of Past Service Cost (Credit)	0	0	120	0
Amortization of Net (Gain) Loss	<u>291,661</u>	<u>5,546</u>	<u>27,058</u>	<u>0</u>
Total Cost	\$ 523,447	\$ 25,332	\$ 206,799	\$ 24,096
2015 Estimated Employer Pension Contributions / Benefit Payments	\$ 364,000	\$ 9,678	\$ 66,521	\$ 26,334
Amounts used for developing net periodic pension/benefit cost				
2015 Actual Employer Pension Contributions / Benefit Payments	\$ 359,292	\$ 24,165	\$ 68,561	\$ 24,823

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Numbers may not add due to rounding.

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EB-2018-0243
Exhibit H1
Tab 1
Schedule 1
Table 1

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2016 to 2017 (\$M)

Line No.	Account	Note	Actual Year End Balance 2016	Audited Year End Balance 2017
			(a)	(b)
			Note 1	Note 2
	Regulated Hydroelectric:			
1	Hydroelectric Water Conditions Variance		(51.0)	(150.2)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(23.5)	(45.0)
3	Hydroelectric Incentive Mechanism Variance		(0.1)	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance		209.9	360.5
5	Income and Other Taxes Variance - Hydroelectric		0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric		4.5	9.0
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		3.9	5.8
8	Pension and OPEB Cost Variance - Hydroelectric - Future		8.4	8.4
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions		26.6	26.6
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric		68.6	83.2
11	Pension & OPEB Cash Payment Variance - Hydroelectric		(7.5)	(25.9)
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance		25.4	25.7
13	Total		265.4	297.9
	Nuclear:			
14	Nuclear Liability Deferral		2.9	18.6
15	Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral		(71.2)	(103.4)
16	Nuclear Development Variance		2.5	1.9
17	Ancillary Services Net Revenue Variance - Nuclear		2.3	3.4
18	Capacity Refurbishment Variance - Nuclear - Capital Portion		(53.6)	(28.0)
19	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion		(49.4)	(58.1)
20	Bruce Lease Net Revenues Variance - Derivative Sub-Account		(68.6)	(69.4)
21	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002		0.0	0.0
22	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions		163.6	189.0
23	Income and Other Taxes Variance - Nuclear		(7.5)	(10.1)
24	Pension and OPEB Cost Variance - Nuclear - Future		171.7	171.7
25	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions		508.9	508.9
26	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear		428.3	530.5
27	Pension & OPEB Cash Payment Variance - Nuclear		(50.5)	(114.0)
28	Pickering Life Extension Depreciation Variance		0.0	0.0
29	Nuclear Deferral and Variance Over/Under Recovery Variance		73.9	74.7
30	Fitness for Duty Deferral	3	n/a	0.1
31	SR&ED ITC Variance	3	n/a	(3.4)
32	Rate Smoothing Deferral	4	n/a	0.0
33	Total		1,053.3	1,112.6
34	Grand Total (line 13 + line 33)		1,318.8	1,410.5

Notes:

- From Ex. H1-1-1, Table 1a, col. (f).
- From Ex. H1-1-1, Table 1c, col. (f).
- This account was established effective June 1, 2017 as per the OEB's Decision and Order in EB-2016-0152.
- This account was established effective January 1, 2017 as per the OEB's Decision and Order in EB-2016-0152. An amount of \$63M was initially credited to the Rate Smoothing Deferral Account in 2017, based upon the rate smoothing proposal presented in OPG's Draft Payment Amounts Order filed in January 2018. This amount was subsequently reversed as the OEB's decision on the PAO ordered no amounts be deferred in the account for 2017.

Numbers may not add due to rounding.

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Exhibit H1
Tab 1
Schedule 1
Table 1a

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - Actual 2015 to 2016 (\$M)

Line No.	Account	Note	Audited Year End Balance 2015	Actual 2016				(a)+(b)+(c)+(d)+(e) Actual Year End Balance 2016
				Transactions	Amortization	Interest	Transfers	
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1		Note 2	Note 3		
	Hydroelectric:							
1	Hydroelectric Water Conditions Variance		(23.0)	(33.0)	5.6	(0.7)	0.0	(51.0)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(24.2)	(9.9)	11.0	(0.3)	0.0	(23.5)
3	Hydroelectric Incentive Mechanism Variance		(1.7)	0.0	1.7	0.0	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance		114.4	125.6	(31.9)	1.9	0.0	209.9
5	Income and Other Taxes Variance - Hydroelectric		(0.1)	(0.0)	0.1	0.0	0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric		83.2	0.8	(79.9)	0.5	0.0	4.5
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	4	0.0	3.9	0.0	0.0	0.0	3.9
8	Pension and OPEB Cost Variance - Hydroelectric - Future	5	9.5	0.0	(1.1)	0.0	0.0	8.4
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	5	32.5	0.0	(5.9)	0.0	0.0	26.6
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric		44.2	24.5	0.0	0.0	0.0	68.6
11	Pension & OPEB Cash Payment Variance - Hydroelectric		4.3	(11.7)	0.0	0.0	0.0	(7.5)
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance		16.5	11.7	(3.0)	0.2	0.0	25.4
13	Total		255.5	111.7	(103.4)	1.6	0.0	265.4
	Nuclear:							
14	Nuclear Liability Deferral		190.5	2.9	(190.5)	0.0	0.0	2.9
15	Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral	6	0.0	(71.2)	0.0	0.0	0.0	(71.2)
16	Nuclear Development Variance		3.3	0.8	(1.6)	0.0	0.0	2.5
17	Ancillary Services Net Revenue Variance - Nuclear		2.1	1.3	(1.2)	0.0	0.0	2.3
18	Capacity Refurbishment Variance - Nuclear - Capital Portion		(32.5)	(15.4)	(5.0)	(0.6)	0.0	(53.6)
19	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion		(30.8)	(17.4)	(0.8)	(0.4)	0.0	(49.4)
20	Bruce Lease Net Revenues Variance - Derivative Sub-Account		(4.5)	0.0	(64.1)	0.0	0.0	(68.6)
21	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002		18.7	0.0	(18.7)	0.0	0.0	0.0
22	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions		103.1	143.0	(82.5)	0.0	0.0	163.6
23	Income and Other Taxes Variance - Nuclear		(13.1)	(3.1)	8.8	(0.1)	0.0	(7.5)
24	Pension and OPEB Cost Variance - Nuclear - Future	5	193.2	0.0	(21.5)	0.0	0.0	171.7
25	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	5	622.0	0.0	(113.1)	0.0	0.0	508.9
26	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear		271.1	157.2	0.0	0.0	0.0	428.3
27	Pension & OPEB Cash Payment Variance - Nuclear		23.4	(73.8)	0.0	(0.1)	0.0	(50.5)
28	Pickering Life Extension Depreciation Variance		5.2	0.0	(5.2)	0.0	0.0	0.0
29	Nuclear Deferral and Variance Over/Under Recovery Variance		81.7	29.0	(37.6)	0.7	0.0	73.9
30	Fitness for Duty Deferral		n/a	n/a	n/a	n/a	n/a	0.0
31	SR&ED ITC Variance		n/a	n/a	n/a	n/a	n/a	0.0
32	Rate Smoothing Deferral		n/a	n/a	n/a	n/a	n/a	0.0
33	Total		1,433.4	153.3	(533.0)	(0.5)	0.0	1,053.3
34	Grand Total (line 13 + line 33)		1,688.9	265.0	(636.3)	1.2	0.0	1,318.8

Notes:

1 From EB-2016-0152, Payment Amounts Order, App. D, Table 1, col. (a) and App. E, Table 1, col. (a), unless otherwise noted.

2 From EB-2016-0152, Payment Amounts Order, App. D, Table 1, col. (b) and App. E, Table 1, col. (b), unless otherwise noted.

3 Per the EB-2014-0370 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Bruce Lease Net Revenues Variance Account (from January 1, 2015 to December 31, 2016), the Pickering Life Extension Depreciation Variance Account or the Nuclear Liability Deferral Account. Per the EB-2015-0374 Decision and Order, no interest is recorded on the Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral Account.

4 As the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in 2016, entries for 2014 and 2015 were calculated retrospectively and added in 2016, consistent with the EB-2014-0369 Decision and Order.

5 As per the Payment Amounts Order for EB-2013-0321, Appendix G, p. 6, effective November 1, 2014, OPG recorded only amortization in the Pension and OPEB Cost Variance Account.

6 This account was established effective January 1, 2016 as per the OEB's Decision and Order in EB-2015-0374.

Numbers may not add due to rounding.

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Exhibit H1
Tab 1
Schedule 1
Table 1b

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - January to May 2017 (\$M)

Line No.	Account	Note	Actual Year End Balance 2016	January 1 to May 31, 2017				(a)+(b)+(c)+(d)+(e)
				Transactions	Amortization	Interest	Transfers	Balance May 31, 2017
			(a)	(b)	(c)	(d)	(e)	(f)
					Note 1	Note 2		
	Hydroelectric:							
1	Hydroelectric Water Conditions Variance		(51.0)	(50.5)	0.0	(0.3)	0.0	(101.7)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(23.5)	(6.0)	0.0	(0.1)	0.0	(29.5)
3	Hydroelectric Incentive Mechanism Variance		(0.1)	0.0	0.0	0.0	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance		209.9	68.3	0.0	1.0	0.0	279.2
5	Income and Other Taxes Variance - Hydroelectric		0.0	0.0	0.0	0.0	0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric		4.5	4.5	0.0	0.0	0.0	9.0
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		3.9	0.7	0.0	0.0	0.0	4.7
8	Pension and OPEB Cost Variance - Hydroelectric - Future	3	8.4	0.0	0.0	0.0	0.0	8.4
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	3	26.6	0.0	0.0	0.0	0.0	26.6
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric		68.6	4.0	0.0	0.0	0.0	72.6
11	Pension & OPEB Cash Payment Variance - Hydroelectric		(7.5)	(5.9)	0.0	(0.1)	0.0	(13.5)
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance		25.4	0.0	0.0	0.1	0.0	25.5
13	Total		265.4	15.1	0.0	0.6	0.0	281.1
	Nuclear:							
14	Nuclear Liability Deferral		2.9	15.7	0.0	0.0	0.0	18.6
15	Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral		(71.2)	(32.1)	0.0	0.0	0.0	(103.4)
16	Nuclear Development Variance		2.5	0.3	0.0	0.0	0.0	2.8
17	Ancillary Services Net Revenue Variance - Nuclear		2.3	0.6	0.0	0.0	0.0	2.8
18	Capacity Refurbishment Variance - Nuclear - Capital Portion		(53.6)	8.2	0.0	(0.2)	0.0	(45.6)
19	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion		(49.4)	6.4	0.0	(0.2)	0.0	(43.2)
20	Bruce Lease Net Revenues Variance - Derivative Sub-Account		(68.6)	0.0	0.0	(0.3)	0.0	(68.9)
21	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002		0.0	0.0	0.0	0.0	0.0	0.0
22	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions		163.6	22.2	0.0	0.8	0.0	186.5
23	Income and Other Taxes Variance - Nuclear		(7.5)	0.1	0.0	0.0	0.0	(7.4)
24	Pension and OPEB Cost Variance - Nuclear - Future	3	171.7	0.0	0.0	0.0	0.0	171.7
25	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	3	508.9	0.0	0.0	0.0	0.0	508.9
26	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear		428.3	27.8	0.0	0.0	0.0	456.2
27	Pension & OPEB Cash Payment Variance - Nuclear		(50.5)	(31.5)	0.0	(0.3)	0.0	(82.2)
28	Pickering Life Extension Depreciation Variance		0.0	0.0	0.0	0.0	0.0	0.0
29	Nuclear Deferral and Variance Over/Under Recovery Variance		73.9	0.0	0.0	0.3	0.0	74.2
30	Fitness for Duty Deferral	4	n/a	n/a	n/a	n/a	n/a	0.0
31	SR&ED ITC Variance	4	n/a	n/a	n/a	n/a	n/a	0.0
32	Rate Smoothing Deferral	5	0.0	0.0	0.0	0.0	0.0	0.0
33	Total		1,053.3	17.7	0.0	0.1	0.0	1,071.1
34	Grand Total (line 13 + line 33)		1,318.8	32.8	0.0	0.7	0.0	1,352.2

- Notes:
- 1 No amortization of deferral and variance account balances was authorized for 2017.
 - 2 Per the EB-2014-0370 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, the Pickering Life Extension Depreciation Variance Account or the Nuclear Liability Deferral Account. Per the EB-2015-0374 Decision and Order, no interest is to be recorded on the Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral Account.
 - 3 As per the Payment Amounts Order for EB-2013-0321, Appendix G, p. 6, effective November 1, 2014, OPG recorded only amortization in the Pension and OPEB Cost Variance Account.
 - 4 This account was established effective June 1, 2017 as per the OEB's Decision and Order in EB-2016-0152.
 - 5 This account was established effective January 1, 2017 as per the OEB's Decision and Order EB-2016-0152.

Numbers may not add due to rounding.

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Table 1c

Table 1c
Deferral and Variance Accounts
Continuity of Account Balances - June to December 2017 (\$M)

Line No.	Account	Note	Balance May 31 2017	June 1 to December 31, 2017				(a)+(b)+(c)+(d)+(e) Audited Year End Balance 2017
				Transactions	Amortization	Interest	Transfers	
				(b)	(c)	(d)	(e)	
			(a)	(b)	Note 1	Note 2	(e)	(f)
	Hydroelectric:							
1	Hydroelectric Water Conditions Variance		(101.7)	(47.5)	0.0	(0.9)	0.0	(150.2)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(29.5)	(15.2)	0.0	(0.3)	0.0	(45.0)
3	Hydroelectric Incentive Mechanism Variance		(0.1)	0.0	0.0	0.0	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance		279.2	78.9	0.0	2.4	0.0	360.5
5	Income and Other Taxes Variance - Hydroelectric		0.0	0.0	0.0	0.0	0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric		9.0	0.0	0.0	0.0	0.0	9.0
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		4.7	1.0	0.0	0.1	0.0	5.8
8	Pension and OPEB Cost Variance - Hydroelectric - Future	3	8.4	0.0	0.0	0.0	0.0	8.4
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	3	26.6	0.0	0.0	0.0	0.0	26.6
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric		72.6	10.6	0.0	0.0	0.0	83.2
11	Pension & OPEB Cash Payment Variance - Hydroelectric		(13.5)	(12.3)	0.0	(0.1)	0.0	(25.9)
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance		25.5	0.0	0.0	0.2	0.0	25.7
13	Total		281.1	15.4	0.0	1.4	0.0	297.9
	Nuclear:							
14	Nuclear Liability Deferral		18.6	0.0	0.0	0.0	0.0	18.6
15	Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral		(103.4)	0.0	0.0	0.0	0.0	(103.4)
16	Nuclear Development Variance		2.8	(0.9)	0.0	0.0	0.0	1.9
17	Ancillary Services Net Revenue Variance - Nuclear		2.8	0.5	0.0	0.0	0.0	3.4
18	Capacity Refurbishment Variance - Nuclear - Capital Portion		(45.6)	17.9	0.0	(0.3)	0.0	(28.0)
19	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion		(43.2)	(14.5)	0.0	(0.4)	0.0	(58.1)
20	Bruce Lease Net Revenues Variance - Derivative Sub-Account		(68.9)	0.0	0.0	(0.5)	0.0	(69.4)
21	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002		0.0	0.0	0.0	0.0	0.0	0.0
22	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions		186.5	1.2	0.0	1.3	0.0	189.0
23	Income and Other Taxes Variance - Nuclear		(7.4)	(2.6)	0.0	(0.1)	0.0	(10.1)
24	Pension and OPEB Cost Variance - Nuclear - Future	3	171.7	0.0	0.0	0.0	0.0	171.7
25	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	3	508.9	0.0	0.0	0.0	0.0	508.9
26	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear		456.2	74.3	0.0	0.0	0.0	530.5
27	Pension & OPEB Cash Payment Variance - Nuclear		(82.2)	(31.0)	0.0	(0.7)	0.0	(114.0)
28	Pickering Life Extension Depreciation Variance	6	0.0	0.0	0.0	0.0	0.0	0.0
29	Nuclear Deferral and Variance Over/Under Recovery Variance		74.2	0.0	0.0	0.5	0.0	74.7
30	Fitness for Duty Deferral	4	0.0	0.1	0.0	0.0	0.0	0.1
31	SR&ED ITC Variance	4	0.0	(3.4)	0.0	0.0	0.0	(3.4)
32	Rate Smoothing Deferral	5	0.0	0.0	0.0	0.0	0.0	0.0
33	Total		1,071.1	41.6	0.0	(0.2)	0.0	1,112.6
34	Grand Total (line 13 + line 33)		1,352.2	57.0	0.0	1.2	0.0	1,410.5

Notes:

- 1 No amortization of deferral and variance account balances was authorized for 2017.
- 2 Per the EB-2014-0370 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, the Pickering Life Extension Depreciation Variance Account or the Nuclear Liability Deferral Account. Per the EB-2015-0374 Decision and Order, no interest is to be recorded on the Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral Account.
- 3 As per the Payment Amounts Order for EB-2016-0152, Appendix G, p. 11, OPG recorded only amortization in the Pension and OPEB Cost Variance Account.
- 4 This account was established effective June 1, 2017 as per the OEB's Decision and Order in EB-2016-0152.
- 5 This account was established effective January 1, 2017 as per the OEB's Decision and Order EB-2016-0152.
- 6 This account was terminated effective June 1, 2017.

Numbers may not add due to rounding.

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Table 2

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017
			(a)	(b)	(c)	(d)
	Previously Regulated Hydroelectric:					
1	Forecast Production (GWh)	1	20,556	8,619	11,937	20,556
2	Actual Calculated Production (GWh)		21,876	9,201	13,313	22,514
3	Difference (GWh) (line 1 - line 2)		(1,320)	(582)	(1,376)	(1,958)
4	Payment Amount (\$/MWh)	2	40.20	40.20	41.67	
5	Revenue Impact (\$M) (line 3 x line 4 / 1000)		(53.1)	(23.4)	(57.3)	(80.7)
6	GRC/Water Rental Costs (\$M)		14.5	8.4	19.8	28.2
7	Addition to Variance Account (\$M) (line 5 + line 6)		(38.5)	(15.0)	(37.5)	(52.5)
	Newly Regulated Hydroelectric:					
8	Forecast Production (GWh)	3	11,876	5,556	6,319	11,876
9	Actual Calculated Production (GWh)		11,678	6,533	6,647	13,179
10	Difference (GWh) (line 8 - line 9)		197	(976)	(327)	(1,304)
11	Payment Amount (\$/MWh)	2	41.93	41.93	41.67	
12	Revenue Impact (\$M) (line 10 x line 11 / 1000)		8.3	(40.9)	(13.6)	(54.6)
13	GRC/Water Rental Costs (\$M)		(2.7)	5.4	3.6	9.0
14	Addition to Variance Account (\$M) (line 12 + line 13)		5.6	(35.5)	(10.0)	(45.6)
15	Total Addition to Variance Account (\$M) (line 7 + line 14)		(33.0)	(50.5)	(47.5)	(98.0)

Notes:

- Value determined as set out in EB-2016-0152 Payment Amounts Order, App. G, pp. 3-4. Previously Regulated value is equal to the average of EB-2013-0321 Payment Amounts Order, App. A, Table 4, line 1, col. (a) and col. (b).
- Cols. (a) and (b) is as per EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3, for Previously Regulated and App. C, Table 1, line 3, for Newly Regulated; and col. (c) from EB-2016-0152 Payment Amounts Order, App. B, Table 1, line 9.
- In accordance with EB-2016-0152 Payment Amounts Order, App. G, pp. 3-4 and EB-2014-0370 Payment Amounts Order, App. B, pp. 4-5, the value represents production for the 21 Newly Regulated hydroelectric facilities subject to the variance account.

Numbers may not add due to rounding.

Table 3
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017
			(a)	(b)	(c)	(d)
	Regulated Hydroelectric:					
	Forecast Revenue:					
1	Previously Regulated Hydroelectric	1	32.5	13.6		
2	Newly Regulated Hydroelectric	1	23.0	9.6		
3	Total Regulated Hydroelectric (line 1 + line 2)	2	55.5	23.1	32.4	55.5
	Actual Revenue:					
4	Previously Regulated Hydroelectric		40.3	21.3		
5	Newly Regulated Hydroelectric		29.9	9.8		
6	Total Regulated Hydroelectric (line 4 + line 5)		70.1	31.0	47.6	78.7
	Addition to Variance Account:					
7	Previously Regulated Hydroelectric (line 1 - line 4)		(7.8)	(7.7)		
8	Newly Regulated Hydroelectric Before Adjustment (line 2 - line 5)		(6.9)	(0.2)		
9	Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment for Newly Regulated Hydroelectric	3	(4.7)	(1.9)		(1.9)
10	Total Regulated Hydroelectric (line 7 + line 8 - line 9)		(9.9)	(6.0)	(15.2)	(21.2)
	Nuclear:					
11	Forecast Revenue	4	1.9	0.8	1.1	1.9
12	Actual Revenue		1.2	0.4	0.5	1.0
13	Addition to Variance Account Before Adjustment (line 11 - line 12)		0.7	0.4	0.5	0.9
14	Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment	5	(0.6)	(0.2)		(0.2)
15	Nuclear Addition to Variance Account (line 13 - line 14)		1.3	0.6	0.5	1.1

Notes:

1 Per EB-2014-0370 Payment Amounts Order, App. B, p. 6.

2 Col. (c) per EB-2016-0152 Payment Amounts Order, App. G, p. 5.

3 Col. (a) is as per EB-2016-0152 H1-1-1 Table 3, line 7. Col. (b) is as per EB-2016-0152 H1-1-1 Table 3, line 7 multiplied by 5 months and divided by 12 months.

4 Col. (a) and (b) per EB-2014-0370 Payment Amounts Order, App. B, page 6. and col. (c) per EB-2016-0152 Payment Amounts Order, App. G, page 5.

5 Col. (a) is as per EB-2016-0152 H1-1-1 Table 3, line 13. Col. (b) is as per EB-2016-0152 H1-1-1 Table 3, line 13 multiplied by 5 months and divided by 12 months.

Numbers may not add due to rounding.

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Table 4

Table 4
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017
			(a)	(b)	(c)	(d)
1	Total Actual Regulated Hydroelectric Incentive Mechanism Net Revenue	1	14.0	5.0	7.4	12.4
2	Threshold	2	54.5	22.7	31.8	54.5
3	Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold (line 1 - line 2; nil if line 1 < line 2)		0.0	0.0	0.0	0.0
4	Percentage	2	50%	50%	50%	50%
5	Addition to Variance Account (line 3 x line 4)		0.0	0.0	0.0	0.0

- Note:
- 1 Annual values as reported in OPG's 2016 Management's Discussion & Analysis (p. 37) and 2017 Management's Discussion & Analysis (p. 42).
 - 2 Annual threshold and percentage per EB-2014-0370 Payment Amounts Order, App. B, pp. 8-9.

Numbers may not add due to rounding.

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Tab 1

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Table 5

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b)+(c) Actual 2017
			(a)	(b)	(c)	(d)
	<u>Previously Regulated Hydroelectric:</u>					
1	Actual Foregone Production Due to SBG Conditions (GWh)	1	2,744	1,544	2,177	3,721
2	Payment Amount (\$/MWh)	2	40.20	40.20	41.67	
3	Revenue (\$M) (line 1 x line 2 / 1000)		110.3	62.1	90.7	152.8
4	GRC/Water Rental Costs (\$M)		(39.5)	(22.2)	(31.3)	(53.6)
5	Addition to Variance Account (\$M) (line 3 + line 4)		70.8	39.8	59.4	99.2
	<u>Newly Regulated Hydroelectric:</u>					
6	Actual Foregone Production Due to SBG Conditions (GWh)	1	1,525	787	717	1,504
7	Payment Amount (\$/MWh)	2	41.93	41.93	41.67	
8	Revenue (\$M) (line 6 x line 7 / 1000)		63.9	33.0	29.9	62.9
9	GRC/Water Rental Costs (\$M)		(9.2)	(4.6)	(10.4)	(14.9)
10	Addition to Variance Account (\$M) (line 8 + line 9)		54.8	28.4	19.5	47.9
11	Total Addition to Variance Account (\$M) (line 5 + line 10)		125.6	68.3	78.9	147.1

Notes:

- 1 Total annual SBG (sum of line 1 and line 6) is as reported in OPG's 2017 Management's Discussion & Analysis (p. 10).
- 2 Col. (a) and (b) per EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 and App. C, Table 1, line 3.
Col. (c) per EB-2016-0152 Payment Amounts Order, App. B, Table 1, line 6, col (a).

Numbers may not add due to rounding.

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Table 6

Table 6
Income and Other Taxes Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016			Actual 2017								
			Regulated Hydroelectric	Nuclear	(a)+(b) Total	Jan - May			Jun - Dec			Total		
						Regulated Hydroelectric	Nuclear	Total	Regulated Hydroelectric	Nuclear	Total	(d) + (g) Hydroelectric Total	(e) + (h) Nuclear Total	(j) + (k) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	<u>Entry (i): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2016 for 2012</u>	1												
1	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		(0.1)	(9.7)	(9.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 1 x 4/3)		(0.1)	(12.9)	(13.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Addition to Variance Account - (line 2 - line 1)		(0.0)	(3.2)	(3.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	<u>Entry (ii): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2017 for 2013</u>	2												
4	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(8.1)	(8.2)	(0.1)	(8.0)	(8.1)
5	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 4 x 4/3)		0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(10.7)	(10.8)	(0.1)	(10.7)	(10.8)
6	Addition to Variance Account (line 5 - line 4)		0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(2.6)	(2.6)	(0.0)	(2.7)	(2.7)
	<u>Entry (iii): Ontario Research and Development Tax Credit (ORDTC) Reduction from 4.5% to 3.5% Effective June 1, 2016</u>													
7	Forecast SR&ED ITCs based on ORDTC at 4.5%		0.1	1.3	1.4	0.0	0.9	0.9	0.0	0.0	0.0	0.2	0.9	1.1
8	Forecast SR&ED ITCs based on ORDTC at 3.5%		0.1	1.0	1.1	0.0	0.7	0.7	0.0	0.0	0.0	0.2	0.7	0.9
9	Reduction in ORDTC (line 7 - line 8)		0.0	0.3	0.3	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.2	0.3
10	Increase in Federal ITCs Associated with ORDTC Reduction		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
11	Tax on ORDTC Reduction (line 9 + line 10) x 25% tax rate)		0.0	0.1	0.1	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	0.1
12	Addition to Variance Account - Reduction in ORDTC Rate (line 9 + line 10 - line 11))		0.0	0.2	0.2	(0.0)	0.1	0.1	(0.0)	(0.0)	(0.0)	0.0	0.1	0.2
13	Total Addition to Variance Account (line 3 + line 6 + line 12)		(0.0)	(3.1)	(3.1)	(0.0)	0.1	0.1	(0.0)	(2.6)	(2.6)	(0.0)	(2.5)	(2.5)

Notes:

1 Recorded in 2016 following the resolution, during 2016, of the 2012 taxation year audit. Amount at line 1 represents SR&ED ITCs, net of tax on ITCs, for 2012 previously credited to ratepayers at 75% through the EB-2010-0008 payment amounts and the December 31, 2014 balance of the Income and Other Taxes Variance Account.

2 Recorded in 2017 following the resolution, during 2017, of the 2013 taxation year audit. Amount at line 4 represents SR&ED ITCs, net of tax on ITCs, for 2013 previously credited to ratepayers at 75% through the EB-2010-0008 payment amounts and the December 31, 2014 balance of the Income and Other Taxes Variance Account.

Numbers may not add due to rounding.

Table 7
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016			Actual 2017								
			Regulated Hydroelectric	Nuclear	(a)+(b) Total	Jan - May			Jun - Dec			Total		
						Regulated Hydroelectric	Nuclear	Total	Regulated Hydroelectric	Nuclear	Total	(d) + (g) Hydroelectric Total	(e) + (h) Nuclear Total	(j) + (k) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Forecast Pension Contributions	1	45.1	280.6	325.7	18.8	116.9	135.7	26.3	116.7	143.0	45.1	233.6	278.7
2	Forecast OPEB Payments	1	12.8	79.9	92.7	5.4	33.3	38.6	7.5	53.2	60.7	12.8	86.4	99.3
3	Total Forecast Pension and OPEB Cash Amounts (line 1 + line 2)		58.0	360.5	418.5	24.2	150.2	174.4	33.8	169.8	203.7	58.0	320.1	378.0
4	Actual Pension Contributions		32.5	201.5	234.0	13.0	84.6	97.6	13.3	85.8	99.1	26.3	170.4	196.7
5	Actual OPEB Payments		13.7	85.2	99.0	5.2	34.1	39.4	8.2	53.0	61.2	13.5	87.2	100.6
6	Total Actual Pension and OPEB Cash Amounts (line 4 + line 5)		46.3	286.7	333.0	18.2	118.7	137.0	21.5	138.8	160.4	39.8	257.6	297.3
7	Total Addition to Pension & OPEB Cash Payment Variance Account (line 6 - line 3)		(11.7)	(73.8)	(85.5)	(5.9)	(31.5)	(37.4)	(12.3)	(31.0)	(43.3)	(18.2)	(62.5)	(80.7)
8	Actual Pension Accrual		46.6	293.3	339.9	12.1	80.1	92.2	16.7	112.4	129.1	28.8	192.5	221.3
9	Actual OPEB Accrual		24.1	150.7	174.8	10.1	66.5	76.6	15.4	100.7	116.1	25.5	167.2	192.8
10	Total Actual Pension and OPEB Accrual (line 8 + line 9)		70.7	444.0	514.7	22.2	146.6	168.8	32.1	213.1	245.3	54.3	359.7	414.0
11	Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account (line 10 - line 6)		24.5	157.2	181.7	4.0	27.8	31.8	10.6	74.3	84.9	14.5	102.2	116.7

Notes:
1 Cols. (a), (b), (d) and (e) per EB-2014-0370 Payment Amounts Order, App. B, page 15-16 (Regulated Hydroelectric amounts are the sum of Previously Regulated and Newly Regulated amounts). Cols. (g) and (h) per EB-2016-0152 Payment Amounts Order, App. G, pages 12-13.

Numbers may not add due to rounding.

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Exhibit H1
Tab 1
Schedule 1
Table 7a

Table 7a
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - 2014 and 2015 (\$M)

Line No.	Particulars	Note	Actual Nov to Dec 2014			Actual 2015		
			Regulated Hydroelectric	Nuclear	(a)+(b) Total	Regulated Hydroelectric	Nuclear	(d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 1	Note 1	Note 2	Note 2	Note 2
1	Forecast Pension Contributions - EB-2013-0321		7.5	46.8	54.3	45.1	280.6	325.8
2	Forecast OPEB Payments - EB-2013-0321		2.1	13.3	15.5	12.8	79.9	92.7
3	Total Forecast Pension and OPEB Cash Amounts (line 1 + line 2)		9.7	60.1	69.8	58.0	360.5	418.5
4	Actual Pension Contributions		7.1	47.7	54.8	46.8	284.5	331.3
5	Actual OPEB Payments		2.8	18.6	21.4	15.2	93.1	108.3
6	Total Actual Pension and OPEB Cash Amounts (line 4 + line 5)		9.8	66.3	76.1	62.1	377.5	439.6
7	Total Addition to Pension & OPEB Cash Payment Variance Account (line 6 - line 3)		0.2	6.2	6.4	4.1	17.0	21.1
8	Actual Pension Accrual		10.4	69.9	80.2	68.3	414.4	482.7
9	Actual OPEB Accrual		4.1	27.8	31.9	33.3	202.8	236.2
10	Total Actual Pension and OPEB Accrual (line 8 + line 9)		14.5	97.6	112.1	101.6	617.3	718.9
11	Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account (line 10 - line 6)		4.6	31.3	36.0	39.5	239.8	279.3

Notes:

- 1 From EB-2016-0152, Ex. L-9.1-1, Staff-209, Attachment 1, Table 1.
- 2 From EB-2016-0152, Ex. H1-1-1, Table 8.

Numbers may not add due to rounding.

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Table 8

Table 8
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2016 and 2017¹ (\$M)

Line No.	Particulars	Note	Actual 2016
			(a)
1	Regulated Hydroelectric Rider (\$/MWh)	2	3.19
2	Regulated Hydroelectric Interim Period Shortfall Rider (\$/MWh)	3	0.64
3	Regulated Hydroelectric Production Forecast Used to Set Rider (TWh)	4	32.5
4	Regulated Hydroelectric Actual Production (TWh)		29.5
5	Actual Production Variance for Previously Regulated Hydroelectric Rider (TWh) (line 3 - line 4)		3.0
6	Addition to Variance Account (\$M) Rider (line 5 x line 1)		9.7
7	Addition to Variance Account (\$M) Interim Period Shortfall Rider (line 5 x line 2)		1.9
8	Total Additions to Variance Account (\$M) (line 6 + line 7)		11.7

Notes:

- 1 There were no riders effective in 2017 and, therefore, there were no over/under recovery entries for 2017.
- 2 From EB-2014-0370 Payment Amounts Order, App A, Table 1, line 12 col (g).
- 3 Interim period shortfall rider from EB-2014-0370 Payment Amounts Order, App A, Table 3, line 4 col (a).
- 4 OEB-approved 2014-2015 previously regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 2 multiplied by 12 months divided by 24 months, plus July 1, 2014 to December 31, 2015 newly regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 2, col. (c) multiplied by 12 months divided by 18 months.

Numbers may not add due to rounding.

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Table 9

Table 9
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account ¹
Summary of Account Transactions - 2014, 2015, 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016			Actual Jan - May 2017	Actual Jun - Dec 2017	(d)+(e) Actual 2017
			For Nov - Dec 2014	For 2015	For 2016			
			(a)	(b)	(c)	(d)	(e)	(f)
	Capital Addition to Variance Account:							
1	Actual Net Plant Rate Base Amount	2	21.4	21.2	20.9	8.6	12.1	20.7
2	Weighted Average Cost of Capital	3	6.86%	6.85%	6.85%	6.85%	6.85%	
3	Actual Cost of Capital Amount (line 1 x line 2)		1.5	1.4	1.4	0.6	0.8	
4	Cost of Capital Variance	1	0.2	1.4	1.4	0.6	0.8	1.4
5	Actual Depreciation		0.0	0.2	0.2	0.1	0.1	0.2
	Income Tax Impact:							
6	Actual Capital Cost Allowance Deduction		0.1	0.8	0.8	0.3	0.4	0.8
7	Net Increase (Decrease) in Regulatory Taxable Income	4	0.0	0.3	0.3	0.1	0.2	0.3
8	Income Tax Rate	5	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
9	Income Tax Impact (line 7 x line 8 / (1 - line 8))		0.0	0.1	0.1	0.0	0.1	0.1
10	Addition to Variance Account (line 4 + line 5 + line 9)		0.3	1.8	1.8	0.7	1.0	1.8

For notes see Table 9a.

Table 9a
Notes to Table 9
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account - 2014, 2015, 2016 and 2017 (\$M)

- Notes:
- 1 Account established as per OEB Decision and Order EB-2014-0369, effective November 1, 2014. As the account was approved in 2016, entries for 2014 and 2015 were calculated retrospectively and recorded in 2016, consistent with the EB-2014-0369 decision and order.
 - 2 The continuity of the variation between the original Niagara Tunnel Project rate base disallowance of \$28M and the varied disallowance of \$6.4M is as follows:

Table to Note 2 - Niagara Tunnel Project Disallowance Continuity (\$M)						
Line No.		2013	2014	2015	2016	2017
		(a)	(b)	(c)	(d)	(e)
1a	Opening Balance	0.0	21.5	21.3	21.0	20.8
2a	In-Service Adjustment	21.6	0.0	0.0	0.0	0.0
3a	Depreciation Expense	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)
4a	Closing Balance	21.5	21.3	21.0	20.8	20.6
5a	Actual Net Plant Rate Base Amount (1a+ 4a)/ 2	10.8	21.4	21.2	20.9	20.7

- 3 Value in col. (a) per EB-2013-0321 Payment Amounts Order, App. A, Table 5b, col. (c), line 6. Values in Cols. (b) to (e) per EB-2013-0321 Payment Amounts Order, App. A, Table 6b.
- 4 The increase in regulatory taxable income is calculated as the sum of lines 5 and 6 plus the ROE component of the cost of capital variance at line 4. The ROE component of the variance is equal to line 2 multiplied by the EB-2013-0321 OEB-approved equity portion (45%) of the capital structure, multiplied by the OEB-approved EB-2013-0321 ROE rate of 9.30% for 2014 and 9.36% thereafter.
- 5 From EB-2013-0321 Payment Amounts Order, App. A, Table 7, line 31, EB-2013-0321 Payment Amounts Order, App. A, Table 8, line 31 and EB-2016-0152 Payment Amounts Order, App. A, Table 16, line 29.

Table 10
Nuclear Liability Deferral Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017
			(a)	(b)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2017:			
1	Depreciation Expense (col. (b) = Table to Note 1, line 3a, col. (d) x 5/12)	1	0.0	9.9
	Return on Rate Base			
2	Average Asset Retirement Costs	2	0.0	(270.3)
3	Weighted Average Accretion Rate	3	5.37%	5.37%
4	Return on Rate Base (line 2 x line 3 x 5/12)		0.0	(6.0)
	Variable Expenses	4		
5	Used Fuel Storage and Disposal Variable Expenses	4	0.0	(1.3)
6	Low & Intermediate Level Waste Management Variable Expenses	4, 5	2.2	2.0
7	Total Variable Expenses (line 5 + line 6)		2.2	0.7
	Income Tax Impact			
8	Forecast Contributions to Nuclear Segregated Funds	6	0.0	71.4
9	Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan	7	0.0	42.7
10	Decrease (Increase) in Contributions to Nuclear Segregated Funds (line 8 - line 9)		0.0	28.7
11	Net Increase in Regulatory Taxable Income (line 1 + line 4 + line 7 + line 10)		2.2	33.3
12	Income Tax Rate		25.00%	25.00%
13	Income Tax Impact (line 11 x line 12 / (1 - line 12))		0.7	11.1
14	Addition to Deferral Account (line 1 + line 4 + line 7 + line 13)		2.9	15.7

Notes:
1 The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 1 - Depreciation Expense (\$M)					
Line No.		Pickering Units 1 & 4 (formerly Pickering A)	Pickering Units 5-8 (formerly Pickering B)	Darlington	Total
		(a)	(b)	(c)	(d)
	Incremental ARC Continuity:				
1a	Asset Retirement Cost ("ARC") Adjustment at December 31, 2016 [#]	32.2	107.4	(398.0)	(258.3)
2a	Remaining Useful Life as at December 31, 2016 (years) ⁺	4.0	4.0	36.0	
3a	2017 Annual Incremental Depreciation (line 1a / line 1b)	8.1	26.8	(11.1)	23.8
4a	Incremental ARC at December 31, 2017	24.2	80.5	(386.9)	(282.2)

From EB-2016-0152, Ex. J21.1, Att. 2, Table 4, line 27, col. (b).

+ Remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2016 based on the end-of-life dates per EB-2016-0152 Ex. F4-1-1.

2 2017 value is calculated as Note 1, col. (d): (line 1a + line 4a)/2.

3 Per EB-2014-0370 Payment Amounts Order, App. B, p. 10.

4 Annual 2017 value calculated as the difference between: (A) the product of (i) 2017 unit cost rates for each of the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan, and (ii) average number of forecast fuel bundles and L&ILW volumes reflected in the EB-2013-0321 payment amounts, and (B) the average of 2014/2015 forecast variable expenses reflected in the EB-2013-0321 payment amounts. For January to May 2017, the annual value is pro-rated by 5/12.

5 The amount in 2016 relates to an asset retirement obligation increase recorded on December 31, 2016 in relation to changes in cost estimates related to the implementation of the 2012 Canadian Nuclear Safety Commission requirements to include certain facilities with Waste Nuclear Substance Licences. These facilities were included for the first time in the 2017-2021 ONFA Reference Plan. In accordance with GAAP, this asset retirement obligation adjustment was expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility not used to support OPG's current operations.

6 Per EB-2013-0321 Payment Amounts Order, App. A, calculated as: average of Table 7, line 14, col. (c) and Table 8, line 14, col. (c) multiplied by 5 / 12.

7 Calculated as EB-2016-0152 Payment Amounts Order, App. A, Table 17, line 14, col. (b) multiplied by 5 / 12.

Numbers may not add due to rounding.

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Table 11

Table 11
Nuclear Development Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017
			(a)	(b)	(c)	(d)
1	Forecast Costs	1	0.0	0.0	1.3	1.3
2	Actual Costs		0.8	0.3	0.5	0.7
3	Addition to Variance Account (line 2 - line 1)		0.8	0.3	(0.9)	(0.6)

Note:

1 Cols. (a) and (b) per EB-2014-0370 Payment Amounts Order, App. B, p. 11. Col. (c) per EB-2016-0152 Payment Amounts Order, App. G, p. 15.

Numbers may not add due to rounding.

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Table 12

Table 12
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017
			(a)	(b)	(c)	(d)
1	Actual Total Bruce Lease Net Revenues (\$M)	1	(114.7)	(13.0)	(4.6)	(17.5)
2	Forecast Bruce Lease Net Revenue	2	40.2	16.7	(3.1)	
3	Forecast Nuclear Production (TWh)	3	47.8	19.9	22.2	
4	Rate Credited to (Recovered from) Customers (\$/MWh) (line 2 / line 3)		0.84	0.84	(0.137)	
5	Actual Nuclear Production (TWh)		45.6	15.9	24.8	
6	Amount Credited to (Recovered from) Customers (\$M) (line 4 x line 5)		38.3	13.4	(3.4)	10.0
7	Total Addition to Variance Account Before Adjustment (\$M) (line 6 - line 1)		152.9	26.3	1.2	27.5
8	Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment (\$M)	4	9.9	4.2		4.2
9	Total Addition to Variance Account (\$M) (line 7 - line 8)		143.0	22.2	1.2	23.3

Notes:

- 1 From Ex. H1-1-1 Table 12a, line 22, cols. (a), (d) and (g).
- 2 Per EB-2014-0370 Payment Amounts Order, App. B, p. 12, \$3.35/month multiplied by 12 months for col. (a) and \$3.35/month multiplied by 5 months for col. (b). Col. (c) is (\$5.3M) from EB-2016-0152 Payment Amounts Order, App. G, p. 16 multiplied by 7 months and divided by 12 months.
- 3 For col. (a), OEB-approved 2014-2015 nuclear production from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2 multiplied by 12 months divided by 24 months.
For col. (b), OEB-approved 2014-2015 nuclear production from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2 multiplied by 5 months divided by 24 months.
For col. (c), OEB-approved 2017 nuclear production from EB-2016-0152 Payment Amounts Order, App. C, Table 1, line 2 multiplied by 7 months divided by 12 months.
- 4 Col. (a) is as per EB-2016-0152 H1-1-1 Table 12, line 8. Col. (b) is as per EB-2016-0152 H1-1-1 Table 12, line 8 multiplied by 5 months and divided by 12 months.

Numbers may not add due to rounding.

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Table 12a

Table 12a
Bruce Lease Net Revenue Variance Account
Comparison of Bruce Lease Net Revenues - 2016 and 2017 (\$M) ¹

Line No.	Particulars	Note	Actual 2016	Average of 2014/2015 OEB Approved (EB-2013-0321)	(b) - (a) Change	Actual Jan - May 2017	5/12 of Average of 2014/2015 OEB Approved (EB-2013-0321)	(e) - (d) Change	Actual June - Dec 2017	7/12 of 2017 OEB Approved (EB-2016-0152)	(h) - (g) Change	(d) + (g) Actual Total 2017	OEB Approved 2017 (EB-2016-0152)	(k) - (j) Change
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
				Note 2			Note 2			Note 3			Note 3	
	Revenues:													
1	Site Services (OPG to Bruce Power)		0.8	0.7	(0.1)	0.0	0.3	0.2	0.5	0.4	(0.1)	0.5	0.7	0.1
2	Low & Intermediate Level Waste Services		9.6	16.0	6.4	2.5	6.7	4.2	8.5	10.4	1.9	11.0	17.8	6.9
3	Cobalt-60		0.7	0.5	(0.2)	0.0	0.2	0.2	0.9	0.3	(0.6)	0.9	0.5	(0.3)
4	Total Services Revenue		11.0	17.2	6.2	2.5	7.2	4.7	9.9	11.1	1.2	12.4	19.1	6.6
5	Fixed (Base) Rent		24.2	38.7	14.5	10.2	16.1	5.9	14.3	14.3	0.0	24.5	24.5	0.0
6	Supplemental Rent - Non-Derivative Portion		151.4	210.0	58.6	66.5	87.5	21.0	92.9	93.6	0.7	159.4	160.4	1.1
7	Amortization of Initial Deferred Rent		12.1	12.1	(0.0)	5.0	5.0	(0.0)	7.0	7.0	(0.0)	12.1	12.1	(0.0)
8	Total Rent Revenue		187.7	260.7	73.1	81.7	108.6	26.9	114.2	114.9	0.7	195.9	197.0	1.1
9	Total Revenue (line 4 + line 8)		198.7	277.9	79.2	84.2	115.8	31.6	124.1	126.0	1.9	208.3	216.0	7.7
	Costs:													
10	Depreciation		101.0	106.8	5.8	28.6	44.5	15.9	40.0	40.0	0.0	68.5	68.6	0.1
11	Property Tax		12.3	14.0	1.7	5.1	5.8	0.7	7.0	7.6	0.6	12.2	13.0	0.8
12	Accretion		511.9	390.1	(121.8)	194.8	162.5	(32.3)	265.1	267.5	2.4	459.9	458.6	(1.3)
13	(Earnings) Losses on Segregated Funds		(374.9)	(353.4)	21.5	(161.8)	(147.2)	14.5	(232.0)	(229.2)	2.8	(393.8)	(393.0)	0.8
14	Used Fuel Storage and Disposal		66.9	55.4	(11.5)	23.5	23.1	(0.4)	33.7	33.2	(0.5)	57.3	57.0	(0.3)
15	Waste Management Variable Expenses and Facilities Removal Costs		4.7	3.1	(1.6)	1.0	1.3	0.2	1.5	1.5	(0.0)	2.5	2.5	(0.0)
16	Interest		34.5	13.3	(21.3)	12.2	5.5	(6.7)	17.7	12.3	(5.4)	29.9	21.1	(8.8)
17	Total Costs Before Income Tax (lines 10 through 16)		356.3	229.1	(127.2)	103.5	95.5	(8.1)	132.9	132.9	(0.1)	236.5	227.7	(8.7)
18	Income Tax - Current	4	34.6	58.1	23.5	25.2	24.2	(1.0)	38.2	35.9	(2.3)	63.4	61.6	(1.8)
19	Income Tax - Deferred	5	(77.6)	(49.4)	28.1	(31.5)	(20.6)	10.9	(42.5)	(39.7)	2.8	(74.0)	(68.1)	5.9
20	Total Income Tax		(43.0)	8.7	51.6	(6.3)	3.6	9.9	(4.3)	(3.8)	0.5	(10.6)	(6.5)	4.1
21	Total Costs (line 17 + line 20)		313.4	237.8	(75.6)	97.2	99.1	1.8	128.6	129.1	0.4	225.9	221.3	(4.6)
22	Total Bruce Lease Net Revenues (line 9 - line 21)		(114.7)	40.2	154.8	(13.0)	16.7	29.7	(4.6)	(3.1)	1.5	(17.5)	(5.3)	12.3

Notes:

- 1 All amounts for 2016 and 2017 are presented on a US GAAP basis, which was used to determine the EB-2013-0321 and EB-2016-0152 OEB-approved forecasts.
- 2 Bruce Lease Net Revenues forecast for 2014 and 2015 is detailed in EB-2013-0321 Ex. G2-2-1, Table 2 (revenues) and Table 5 (costs).
- 3 Bruce Lease Net Revenues forecast for 2017 is detailed in EB-2016-0152 Ex. J21.2 Attachment 1, Table 1.
- 4 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 12b, line 20.
- 5 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 12b, line 27.

Table 12b
Bruce Lease Net Revenues Variance Account
Calculation of Bruce Income Taxes - 2016 and 2017 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual June - Dec 2017	(b)+(c) Actual Total 2017
			(a)	(b)	(c)	(d)
	Determination of Taxable Income					
1	Earnings (Loss) Before Tax	1	(157.6)	(19.3)	(8.8)	(28.1)
	Additions for Tax Purposes - Temporary Differences:					
2	Base Rent Accrual		63.8	26.4	39.1	65.5
3	Depreciation		101.0	28.6	40.0	68.5
4	Accretion		511.9	194.8	265.1	459.9
5	Used Fuel and Waste Management Expenses and Facilities Removal Costs		71.6	24.6	35.2	59.8
6	Receipts from Nuclear Segregated Funds		31.6	15.8	21.9	37.7
7	Other		18.1	5.1	15.6	20.7
8	Total Additions - Temporary Differences		798.0	295.3	416.8	712.1
	Deductions for Tax Purposes - Permanent Differences:					
9	Deferred Rent Revenue		14.2	5.9	8.3	14.2
	Deductions for Tax Purposes - Temporary Differences:					
10	CCA		5.6	2.6	3.1	5.7
11	Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal		134.1	47.6	71.6	119.2
12	Contributions to Nuclear Segregated Funds		(26.9)	(42.7)	(59.8)	(102.5)
13	Earnings (Losses) on Nuclear Segregated Funds		374.9	161.8	232.0	393.8
14	Total Deductions - Temporary Differences		487.7	169.2	246.9	416.2
15	Taxable Income/(Loss) Before Loss Carry-Over (line 1 + line 8 - line 9 - line 14)		138.4	100.9	152.8	253.7
16	Tax Loss Carry-Over to Future Years / (from Prior Years)		0.0	0.0	0.0	0.0
17	Taxable Income After Loss Carry-Over (line 16 + line 17)		138.4	100.9	152.8	253.7
	Determination of Total Current Income Taxes					
18	Taxable Income After Loss Carry-Over (from line 17)		138.4	100.9	152.8	253.7
19	Income Tax Rate - Current		25.00%	25.00%	25.00%	25.00%
20	Income Taxes - Current		34.6	25.2	38.2	63.4
	Determination of Total Deferred Income Taxes					
21	Total Net Temporary Differences (line 8 - line 14)		310.3	126.1	169.9	296.0
22	Income Tax Rate - Deferred		25.00%	25.00%	25.00%	25.00%
23	Deferred Income Taxes		(77.6)	(31.5)	(42.5)	(74.0)
24	Tax Loss / Tax Loss Carry-Over (line 15 or line 16)		0.0	0.0	0.0	0.0
25	Income Tax Rate - Current		25.00%	25.00%	25.00%	25.00%
26	Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over		0.0	0.0	0.0	0.0
27	Deferred Income Tax - Total (line 23 + line 26)		(77.6)	(31.5)	(42.5)	(74.0)
	Income Tax Rate - Current					
28	Federal Tax		15.00%	15.00%	15.00%	15.00%
29	Provincial Tax net of Manufacturing & Processing Profits Deduction		10.00%	10.00%	10.00%	10.00%
30	Total Income Tax Rate - Current		25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term					
31	Federal Tax		15.00%	15.00%	15.00%	15.00%
32	Provincial Tax net of Manufacturing & Processing Profits Deduction		10.00%	10.00%	10.00%	10.00%
33	Total Income Tax Rate - Long-Term		25.00%	25.00%	25.00%	25.00%

Notes:
1 Earnings (Loss) Before Tax is derived as the difference between Total Revenue in Ex. H1-1-1, Table 12a, line 9 and Total Costs Before Income Tax in Ex. H1-1-1, Table 12a, line 17.

Numbers may not add due to rounding.

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Table 13

Table 13
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2016 and 2017¹ (\$M)

Line No.	Particulars	Note	Actual 2016
			(a)
1	Nuclear Rider (\$/MWh)	2	10.84
2	Nuclear Interim Period Shortfall Rider (\$/MWh)	3	2.17
3	Nuclear Production Forecast Used to Set Nuclear Rider (TWh)	4	47.8
4	Actual Nuclear Production (TWh)		45.6
5	Actual Production Variance for Nuclear Rider (TWh) (line 3 - line 4)		2.2
6	Nuclear Production Forecast Used to Set Interim Period Shortfall Rider (TWh)	4	47.8
7	Actual Nuclear Production (TWh)		45.6
8	Actual Production Variance for Interim Period Shortfall Rider (TWh) (line 6 - line 7)		2.2
9	Addition To Variance Account (\$M) Rider (line 5 x line 1)		24.2
10	Addition to Variance Account (\$M) Interim Period Shortfall Rider (line 8 x line 2)		4.8
11	Addition to Variance Account (\$M) (line 9 + line 10)		29.0

Notes:

- 1 There were no riders effective in 2017 and, therefore, there were no over/under recovery entries.
- 2 From EB-2014-0370 Payment Amounts Order, App A, Table 2, line 16 col (g).
- 3 Interim period shortfall rider from EB-2014-0370 Payment Amounts Order, App A, Table 3, line 4 col (b).
- 4 Board-approved 2014-2015 nuclear production from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2 multiplied by 12 months divided by 24 months.

Numbers may not add due to rounding.

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Tab 1
Schedule 1
Table 14

Table 14
Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015)¹
Summary of Account Transactions - 2016 and 2017 (\$M)

Line No.	Description	Note	Actual 2016	Actual Jan - May 2017
			(a)	(b)
	Return on Rate Base:			
1	Accretion Rate on Lesser of ARC and UNL	3	(23.8)	(9.7)
2	Non-ARC Rate Base		0.2	0.1
3	Total Return on Rate Base Impact (line 1 + line 2)		(23.6)	(9.6)
	Depreciation Expense:			
4	Asset Retirement Costs	4	(30.5)	(12.6)
5	Non-Asset Retirement Costs	5	(4.4)	(1.8)
6	Total Depreciation Expense Impact (line 4 + line 5)		(34.9)	(14.5)
	Other Expenses:			
7	Used Fuel Storage and Disposal Variable Expenses	6, 8	5.0	0.0
8	Low & Intermediate Level Waste Management Variable Expenses	7, 8	0.1	0.0
9	Total Other Expenses Impact (line 7 + line 8)		5.1	0.0
	Income Taxes:			
10	Return on Rate Base - Non-ARC Impact (line 2 x (25%/75%))		0.0	0.0
11	Depreciation Expense on Non-Asset Retirement Costs (line 5 x (25%/75%))		(1.5)	(0.6)
12	Total Non-ARC Income tax Impact		(1.5)	(0.6)
13	Accretion Rate on Lesser of ARC and UNL (line 1 x (25%/75%))		(7.9)	(3.2)
14	Depreciation Expense on Asset Retirement Costs (line 4 x (25%/75%))		(10.2)	(4.2)
15	Used Fuel Storage and Disposal Variable Expenses (line 7 x (25%/75%))		1.7	0.0
16	Low & Intermediate Level Waste Management Variable Expenses (line 8 x (25%/75%))		0.0	0.0
17	Total Non-ARC Income tax Impact (line 13 + line 14 + line 15 + line 16)		(16.4)	(7.4)
18	Total Income Tax Impact (line 12 + line 17)		(17.8)	(8.0)
19	Total Projected Revenue Requirement Impact - Prescribed Facilities (line 3 + line 6 + line 9 + line 18)		(71.2)	(32.1)
20	Revenue Requirement Impact of Non-ARC Depreciation - Prescribed Facilities (line 2 + line 5 + line 12)		(5.8)	(2.4)
21	Revenue Requirement Impact Excluding Non-ARC Depreciation - Prescribed Facilities (line 19 - line 20)		(65.5)	(29.8)

Notes:

- 1 Calculations in this table follow the methodology in EB-2012-0002, Ex. M1-1, Attachment 3, Table 1 and EB-2016-0152, Ex. C2-1-1, Table 6, as applicable.
- 2 Col. (a) per EB-2016-0152, Ex. C2-1-1, Table 6, line 4, col. (c). Col. (b) is calculated as (i) x (ii) x 5/12, where (i) is EB-2016-0152, Ex. C2-1-1, Table 2, line 26, col. (e) less EB-2016-0152, Ex. C2-1-1, Table 5a, Note 2, line 4a, col. (b) and (ii) is from EB-2016-0152 Payment Amounts Order, App. A, Table 11, line 7, col. (c).
- 3 Col. (a) per EB-2016-0152, Ex. C2-1-1, Table 6, line 1, col. (c). Col. (b) per EB-2016-0152, Ex. C2-1-1, Table 5, line 1: col. (f) - col. (a), multiplied by 5 months and divided by 12 months.
- 4 Col. (a) consistent with EB-2016-0152 Ex. F4-1-1, p. 6. Col. (b) is col. (a) multiplied by 5 months and divided by 12 months.
- 5 Col. (a) per EB-2016-0152, Ex. C2-1-1, Table 6, line 2, col. (c).
- 6 The 2017 amount is nil to avoid duplication of impacts recorded in the Nuclear Liability Deferral Account. Consistent with EB-2016-0152 Ex. H1-1-1, p. 22, footnote 20, additions to the Nuclear Liability Deferral Account and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account for 2017 have been calculated to avoid duplication.

Numbers may not add due to rounding.

Filed: 2018-08-09

EB-2018-0243

Exhibit H1

Tab 1

Schedule 1

Table 15

Table 15
Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits (ITCs) Variance Account
Summary of Account Transactions - 2017 (\$M)

Line No.	Particulars	Note	Actual Jun - Dec 2017
			(a)
			Note 1
1	Forecast Annual SR&ED ITCs	2	18.4
2	Less Tax on Provincial Portion Taxable in Current Year		(0.9)
3	Forecast Annual SR&ED ITCs, net of Tax		17.5
4	Actual Annual SR&ED ITCs Recorded in 2017		22.9
5	Less Tax on Provincial Portion Taxable in Current Year		(1.1)
6	Actual Annual SR&ED ITCs Recorded in 2017, net of Tax	3	21.8
7	Total Addition to Variance Account $(7/12 \times (\text{line 3} - \text{line 6}) / (1-25\%))$		(3.4)

Notes:

- 1 Account established as per OEB Decision and Order EB-2016-0152, effective June 1, 2017.
- 2 Amount underpinning 2017 nuclear payment amount, per EB-2016-0152, PAO, App. A, Table 1, line 23, col. (c).
- 3 Represents the estimated value reflected in OPG's 2017 audited consolidated financial statements. The final value is determined in 2018 as part of the filing of the 2017 tax return, to be trued as part of the 2018 entries in the variance account.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's proposed approach for clearing the audited December 31, 2017 balances in the company's deferral and variance accounts ("D&V accounts").

2.0 SUMMARY

OPG requests clearance of the audited December 31, 2017 balances in the D&V accounts, less amortization amounts previously-approved by the OEB in EB-2016-0152, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, through new payment riders for the January 1, 2019 to December 31, 2021 period. As outlined in Ex. H1-1-1, OPG proposes to dispose of balances in all D&V accounts not otherwise approved for recovery in the EB-2016-0152 Payment Amounts Order ("EB-2016-0152 PAO"), with the exception of the Capacity Refurbishment Variance Account and the Fitness for Duty Deferral Account. OPG is proposing to defer the clearance of the Capacity Refurbishment Variance Account and the Fitness for Duty Deferral Account for the reasons set out in Ex. H1-1-1, sections 5.6 and 5.19, respectively. Audited balances at December 31, 2017 are presented at Ex. H1-1-1 Table 1 and discussed at Ex. H1-1-1. The income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account are discussed in Ex. F1-1-1, sections 3.1 and 4.0.

The EB-2016-0152 PAO dated March 29, 2018 authorized a hydroelectric payment rider (Hydroelectric Payment Rider A) for the recovery of approved D&V account balances for the hydroelectric facilities.¹ The amount approved for disposition in EB-2016-0152 is a debit of \$86.8M,² reflecting recovery of audited December 31, 2015 balances less amortization of amounts approved in EB-2014-0370. Hydroelectric Payment Rider A is effective March 1, 2018 to December 31, 2020.

¹ EB-2016-0152 PAO, p. 11.

² EB-2016-0152 PAO, Appendix D, col. h), line 12.

1 The EB-2016-0152 PAO also authorized a nuclear payment rider (Nuclear Payment Rider A)
2 for the recovery of approved D&V account balances for the nuclear facilities.³ The amount
3 approved for disposition in EB-2016-0152 is a debit of \$217.9M,⁴ reflecting recovery of audited
4 December 31, 2015 balances less amortization of amounts approved in EB-2014-0370.
5 Nuclear Payment Rider A is effective March 1, 2018 to December 31, 2020.

6
7 Section 3.0 describes the methodology for the proposed recovery of the balances in the D&V
8 accounts and the income tax impacts associated with the recovery of the Pension & OPEB
9 Cash Versus Accrual Differential Deferral Account. Section 4.0 describes the proposed
10 recovery periods for the regulated hydroelectric and nuclear D&V account balances. Section
11 5.0 describes the payment riders proposed for the recovery of these balances.

12 13 **3.0 METHODOLOGY**

14 OPG proposes to calculate new, separate hydroelectric and nuclear payment riders
15 (Hydroelectric Payment Rider C and Nuclear Payment Rider C) for the period from January 1,
16 2019 to December 31, 2021 in the form of \$/MWh payment riders consistent with the form of
17 payment rider approved in decisions and payment amounts orders issued in EB-2016-0152,
18 EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008.

19
20 The approach OPG has used to calculate the proposed hydroelectric and nuclear payment
21 riders is consistent with the methodology previously approved by the OEB. Under this
22 approach, OPG calculates each rider separately using the following three steps. First, a
23 recovery period is determined for each account (or other approved amount⁵) to be cleared.
24 Second, based on each account's, or other approved amount's, recovery period and the
25 audited balance in the account less any amortization already approved, the amount to be
26 amortized in each year of the period is determined. Finally, the total amount to be amortized

³ EB-2016-0152 PAO, p. 12.

⁴ EB-2016-0152 PAO, Appendix E, col. h), line 16.

⁵ For example, the EB-2016-0152 PAO approved riders for the recovery of hydroelectric and nuclear interim period revenue shortfall amounts related to the period between the effective date and the implementation date of approved payment amounts. In this Application, the proposed other approved amount is the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

each year is divided by annual energy production volumes to determine the payment riders in each year.

OPG proposes to calculate Hydroelectric Payment Rider C using the annualized OEB-approved hydroelectric production forecast, consistent with the production used to determine OPG's weighted average payment amounts under O. Reg. 53/05 and customer bill impacts in EB-2016-0152.⁶ Similarly, OPG proposes to calculate the Nuclear Payment Rider C using the nuclear production forecast approved in EB-2016-0152.⁷ Any differences between the production amounts used to set the payment amount riders and actual production will continue to be addressed through entries into the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and Nuclear Deferral and Variance Over/Under Recovery Variance Account.

4.0 RECOVERY PERIODS

With the exception of the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and the Pension and OPEB Cost Variance Account, discussed below, OPG proposes to recover the D&V account balances over the three-year period January 1, 2019 to December 31, 2021.

A three-year recovery period would be consistent with the recovery period for D&V account balances and interim period revenue shortfall approved by the OEB in EB-2016-0152 (i.e., 34 months from March 1, 2018 to December 31, 2020). A three-year recovery period also matches the remaining portion of the current five-year rate-setting term ending on December 31, 2021, reducing complexity in future rate-setting periods by reducing the impact of previously approved D&V account recoveries.

To mitigate customer bill impacts, OPG proposes a longer recovery period for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Bruce Lease Net Revenues

⁶ The average of the 2014 and 2015 OEB-approved hydroelectric production forecast of 33TWh (EB-2016-0152 PAO, Appendix I, Table 2, note 3).

⁷ EB-2016-0152 PAO, Appendix E, Table 1, line 17, note 5; and EB-2016-0152 PAO, Appendix F, Table 2, lines 9 to 11.

Variance Account – Non-Derivative Sub-Account. OPG proposes to recover these balances totalling \$783M⁸ over an amortization period of 8 years (96 months from January 1, 2019 to December 31, 2026). The eight-year term is consistent with prior recovery terms approved by the OEB for OPG's Pension and OPEB Cost Variance Account balances as part of settlement agreements, as it is near the mid-point of those prior approved terms of 6 and 12 years.^{9, 10} The eight-year term also is consistent with the expected end of the next five-year rate-setting term (i.e., 2022 to 2026) for OPG's nuclear and hydroelectric payment amounts. As discussed in Ex. F1-1-1, OPG will incur additional income tax of approximately \$205M due to the recovery of the balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. OPG proposes to recover these income tax impacts over the same term as the balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, with approximately \$77M being recovered in the three-year period from January 1, 2019 to December 31, 2021.¹¹

The recovery periods for the Pension and OPEB Cost Variance Account were approved by the OEB in prior decisions and orders, as described in the EB-2016-0152 PAO.¹² The recovery terms used by OPG in determining the payment riders proposed in this Application reflect these prior decisions and orders. Specifically, OPG proposes:

- 1) To clear the remaining balance in the Pension and OPEB Cost Variance Account (Future Recovery), which is to be recovered by December 31, 2024, using an amortization period of 6 years (72 months from January 1, 2019 to December 31, 2024).
- 2) To clear the remaining balance in the Pension and OPEB Cost Variance Account (Post 2012 Additions), which is to be recovered by June 30, 2021, using an amortization period of 2.5 years (30 months from January 1, 2019 to June 30, 2021).

⁸ Equaling the sum of Ex. H1-2-1, Table 1, line 10, Ex. H1-2-1, Table 2, lines 8, 9 and 13; which total excludes the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

⁹ Pension and OPEB Cost Variance Account – Future Recovery was approved for recovery over 12 years in EB-2012-0002. Pension and OPEB Cost Variance Account – Post 2012 Additions was approved for recovery over 6 years in EB-2014-0370.

¹⁰ The December 31, 2012 non-derivative balance of the Bruce Lease Net Revenues Variance Account was approved for recovery over a longer period of four years in EB-2012-0002, as part of a settlement agreement.

¹¹ Ex. H1-2-1 Table 1, line 14, col. (h) (hydroelectric), plus Table 2, line 20, col. (h) (nuclear).

¹² EB-2016-0152 PAO, Appendix G, p. 11.

5.0 PAYMENT RIDERS

The calculation of the Hydroelectric Payment Rider C is shown in Ex. H1-2-1 Table 1, while the Nuclear Payment Rider C calculation is shown in Ex. H1-2-1 Table 2. For both tables, the 2017 audited D&V account balances (col. a) less the approved amortization in EB-2016-0152 (col. b) and amounts deferred to future applications (col. f) results in the balance available for recovery (col. e). The recovery terms described in section 4.0 (Tables 1 and 2 col. (f)) are used to determine the amount to be amortized in each year of the 2019 to 2021 period for which D&V account riders are proposed, as discussed in section 3.0. Remaining unamortized balances as at December 31, 2021 are also provided (col. k) to illustrate full disposition of balances available for recovery.

The proposed Hydroelectric Payment Rider C is calculated using the amounts available for recovery in each year, comprising the total of hydroelectric D&V account amortizations in the year and the income tax impacts associated with the recovery of the hydroelectric component of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, divided by the approved production forecast for the regulated hydroelectric facilities, as set out in section 3.0. The resulting rider in effect from January 1, 2019 to December 31, 2020 would be \$1.65/MWh, and the rider from January 1, 2021 to December 31, 2021 would be \$1.56/MWh, as shown in Table 1.

The proposed Nuclear Payment Rider C is calculated using the amounts available for recovery in each year, comprising the total of nuclear D&V account amortizations in the year and the income tax impacts associated with the recovery of the nuclear component of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, divided by the OEB-approved production forecast for the nuclear facilities, as set out in section 3.0. The resulting riders would be as follows and as show in Ex. H1-2-1, Table 2:

- From January 1, 2019 to December 31, 2019, the rider in effect would be \$4.55/MWh.
- From January 1, 2020 to December 31, 2020, the rider in effect would be \$4.76/MWh.
- From January 1, 2021 to December 31, 2021, the rider in effect would be \$3.43/MWh.

Numbers may not add due to rounding.

Table 1
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric (\$M)

Line No.	Account	Note	Audited Year End Balance 2017	OEB-Approved Amortization	(a)-(b) 2017 Balance Less Approved Amortization	Amounts Deferred to Future Applications	(c)-(d) Amounts Recoverable in Current Application	Recovery Period (months)	Amortization Jan - Dec 2019	Amortization Jan - Dec 2020	Amortization Jan - Dec 2021	(g)+(h)+(i) Amortization	(c)-(j) Unamortized Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 1	Note 2									
1	Hydroelectric Water Conditions Variance		(150.2)	(17.3)	(132.9)	0.0	(132.9)	36	(44.3)	(44.3)	(44.3)	(132.9)	0.0
2	Ancillary Services Net Revenue Variance - Hydroelectric		(45.0)	(13.2)	(31.8)	0.0	(31.8)	36	(10.6)	(10.6)	(10.6)	(31.8)	0.0
3	Hydroelectric Incentive Mechanism Variance		(0.1)	(0.1)	(0.0)	0.0	(0.0)	36	(0.0)	(0.0)	(0.0)	(0.0)	0.0
4	Hydroelectric Surplus Baseload Generation Variance		360.5	82.5	278.0	0.0	278.0	36	92.7	92.7	92.7	278.0	0.0
5	Income and Other Taxes Variance - Hydroelectric		0.0	(0.0)	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric		9.0	3.3	5.7	5.7	0.0		0.0	0.0	0.0	0.0	5.7
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account		5.8	0.0	5.8	0.0	5.8	36	1.9	1.9	1.9	5.8	0.0
8	Pension and OPEB Cost Variance - Hydroelectric - Future	3	8.4	2.1	6.3	0.0	6.3	72	1.1	1.1	1.1	3.2	3.2
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	4	26.6	11.8	14.8	0.0	14.8	30	5.9	5.9	3.0	14.8	0.0
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric	5	83.2	0.0	83.2	0.0	83.2	96	10.4	10.4	10.4	31.2	52.0
11	Pension & OPEB Cash Payment Variance - Hydroelectric		(25.9)	4.3	(30.1)	0.0	(30.1)	36	(10.0)	(10.0)	(10.0)	(30.1)	0.0
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance		25.7	13.5	12.2	0.0	12.2	36	4.1	4.1	4.1	12.2	0.0
13	Total		297.9	86.8	211.1	5.7	205.4		51.1	51.1	48.1	150.3	60.8
14	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric	5, 7			27.7	0.0	27.7	96	3.5	3.5	3.5	10.4	17.3
15	Total Recoverable Amount				238.8	5.7	233.1		54.5	54.5	51.6	160.7	78.2
16	Forecast Production (TWh)	6							33.0	33.0	33.0		
17	Regulated Hydroelectric Payment Rider (\$/MWh) (line 15 / line 16)								1.65	1.65	1.56		

- Notes:
- 1 From Ex. H1-1-1 Table 1, col (b).
 - 2 From PAO, App. D, Table 1, col. (h).
 - 3 Amortized over the 72 month period from January 1, 2019 to December 31, 2024.
 - 4 Amortized over the 30 month period from January 1, 2019 to June 30, 2021.
 - 5 Amortized over the 96 month period from January 1, 2019 to December 31, 2026.
 - 6 From PAO App. I, Table 2, line 3.
 - 7 Col. (c) calculated as: line 10 * tax rate / (1 - tax rate) = line 10 * (0.25 / 0.75).

Numbers may not add due to rounding.

Table 2
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear (\$M)

Line No.	Account	Note	Audited Year End Balance 2017	OEB-Approved Amortization	(a)-(b) 2017 Balance Less Approved Amortization	Amounts Deferred to Future Applications	(c)-(d) Amounts Recoverable in Current Application	Recovery Period (months)	Amortization Jan - Dec 2019	Amortization Jan - Dec 2020	Amortization Jan -Dec 2021	(g)+(h)+(i) Amortization	(c)-(j) Unamortized Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 1	Note 2									
1	Nuclear Liability Deferral		18.6	0.0	18.6	0.0	18.6	36	6.2	6.2	6.2	18.6	0.0
2	Impact Resulting from Changes in Station End-of-Life Dates (Dec 31, 2015)		(103.4)	0.0	(103.4)	0.0	(103.4)	36	(34.5)	(34.5)	(34.5)	(103.4)	0.0
3	Nuclear Development Variance		1.9	1.7	0.2	0.0	0.2	36	0.1	0.1	0.1	0.2	0.0
4	Ancillary Services Net Revenue Variance - Nuclear		3.4	1.0	2.4	0.0	2.4	36	0.8	0.8	0.8	2.4	0.0
5	Capacity Refurbishment Variance - Nuclear - Capital Portion		(28.0)	(37.6)	9.5	9.5	0.0		0.0	0.0	0.0	0.0	9.5
6	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion		(58.1)	(31.6)	(26.5)	(26.5)	0.0		0.0	0.0	0.0	0.0	(26.5)
7	Bruce Lease Net Revenues Variance - Derivative Sub-Account		(69.4)	(68.6)	(0.8)	0.0	(0.8)	36	(0.3)	(0.3)	(0.3)	(0.8)	0.0
8	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002		0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0
9	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	5	189.0	20.6	168.4	0.0	168.4	96	21.1	21.1	21.1	63.2	105.3
10	Income and Other Taxes Variance - Nuclear		(10.1)	(4.3)	(5.7)	0.0	(5.7)	36	(1.9)	(1.9)	(1.9)	(5.7)	0.0
11	Pension and OPEB Cost Variance - Nuclear - Future	3	171.7	42.9	128.8	0.0	128.8	72	21.5	21.5	21.5	64.4	64.4
12	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	4	508.9	226.2	282.7	0.0	282.7	30	113.1	113.1	56.5	282.7	0.0
13	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear	5	530.5	0.0	530.5	0.0	530.5	96	66.3	66.3	66.3	198.9	331.6
14	Pension & OPEB Cash Payment Variance - Nuclear		(114.0)	23.4	(137.4)	0.0	(137.4)	36	(45.8)	(45.8)	(45.8)	(137.4)	0.0
15	Pickering Life Extension Depreciation Variance		0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0
16	Nuclear Deferral and Variance Over/Under Recovery Variance		74.7	44.1	30.6	0.0	30.6	36	10.2	10.2	10.2	30.6	0.0
17	Fitness for Duty Deferral		0.1	0.0	0.1	0.1	0.0		0.0	0.0	0.0	0.0	0.1
18	SR&ED ITC Variance		(3.4)	0.0	(3.4)	0.0	(3.4)	36	(1.1)	(1.1)	(1.1)	(3.4)	0.0
19	Total		1,112.6	217.9	894.7	(16.9)	911.6		155.6	155.6	99.1	410.4	484.3
20	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear	5, 7			176.8	0.0	176.8	96	22	22	22	66	110.5
21	Total Recoverable Amount				1,071.5	(16.9)	1,088.4		177.7	177.7	121.2	476.7	594.9
22	Forecast Production (TWh)	6							39.0	37.4	35.4		
23	Nuclear Payment Rider (\$/MWh) (line 21 / line 22)								4.55	4.76	3.43		

- Notes:
- 1 From Ex. H1-1-1 Table 1, col (b)
 - 2 From PAO, App. E, Table 1, col. (h).
 - 3 Amortized over the 72 month period from January 1, 2019 to December 31, 2024.
 - 4 Amortized over the 30 month period from January 1, 2019 to June 30, 2021.
 - 5 Amortized over the 96 month period from January 1, 2019 to December 31, 2026.
 - 6 From EB-2016-0152 PAO App. C, Table 1, line 2.
 - 7 Col. (c) calculated as: line 13 * tax rate / (1 - tax rate) = line 13 * (0.25 / 0.75).

2019 HYDROELECTRIC PAYMENT AMOUNT

1.0 PURPOSE

This evidence supports the approval and implementation of the 2019 Hydroelectric Payment Amount ("HPA") effective January 1, 2019, pursuant to the price-cap index approved for OPG's regulated hydroelectric facilities in the EB-2016-0152 Decision and Order issued on December 28, 2017 (the "EB-2016-0152 Decision").

2.0 OVERVIEW

OPG requests the OEB to approve an HPA effective January 1, 2019, based on the requirements of the EB-2016-0152 Payment Amounts Order (the "EB-2016-0152 PAO"), the EB-2016-0152 Decision, and the relevant index values expected to be published by the OEB in the fall of 2018.¹ Section 3.0 summarizes the annual HPA adjustment framework. Section 4.0 summarizes OPG's proposal to implement the 2019 HPA.

3.0 HYDROELECTRIC PAYMENT AMOUNT

The EB-2016-0152 PAO established a 2017 HPA of \$41.67/MWh and a 2018 HPA of \$42.05/MWh², and required that:

"For the periods January 1, 2019 to December 31, 2019, January 1, 2020 to December 31, 2020 and January 1, 2021 to December 31, 2021, the HPA amounts will be determined through an annual hydroelectric payment amount adjustment application. The HPA for each year shall be determined using the price-cap index proposed by OPG in Ex. A1-3-2 of this proceeding, under which the HPA for the prior year is adjusted by the generation industry-weighted inflation factor (using the most current Statistics Canada values for GDP-IPI (FDD) and Ontario AWE), less a productivity factor of 0% less a stretch factor of 0.3%."³

The EB-2016-0152 Decision requires that the HPA for each year be determined using the price-cap index proposed by OPG in EB-2016-0152 Ex. A1-3-2 (the "approved methodology"). The

¹ Index values for the Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI FDD") and Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE") from Statistics Canada are typically published each fall by the OEB.

² EB-2016-0152 PAO, p. 9, paragraph 3.

³ *Ibid.*

EB-2016-0152 Decision established the formula to be applied to adjust rates annually, the base payment amount to which the annual adjustment formula is to be applied, and the basis upon which inputs to the annual adjustment formula are determined. The methodology approved by the OEB is as follows⁴:

$$\text{Payment Amount}(t) = \text{Payment Amount}(t-1) \times \left(1 + \frac{\text{Inflation Factor}}{\left(\frac{\text{Productivity Factor}}{\text{Stretch Factor}} \right)} \right)$$

OPG has calculated the proposed 2019 HPA pursuant to the approved methodology. Specifically:

1) **Prior Year's Payment Amount:** The approved 2018 HPA is \$42.05/MWh as established in the EB-2016-0152 PAO.⁵

2) **Inflation Factor**

The composite inflation index approved by the OEB in EB-2016-0152 is determined using the annual change in the following sub-indices (and respective weightings):⁶

- i. GDP-IPI FDD from Statistics Canada applied to generation industry capital costs (81%) and non-labour O&M costs (7%); and
- ii. Ontario AWE from Statistics Canada applied to generation industry labour costs (12%).

The resulting approved formula for determining the annual inflation factor is:

$$[(81\% + 7\%) \times \text{GDP-IPI FDD}] + [12\% \times \text{Ontario AWE}]$$

As the OEB is not expected to publish the Statistics Canada values to be used for setting 2019 rates until the fall of 2018, OPG has estimated the 2019 HPA using the current values for GDP-IPI FDD and Ontario AWE published by the OEB for 2016, the 2017 values for the

⁴ EB-2016-0152 Decision, p. 121.

⁵ EB-2016-0152 PAO, p. 9, paragraph 3.

⁶ EB-2016-0152 Decision, p. 122.

indices published by Statistics Canada, and the OEB-approved weighting of the indices, resulting in an estimated inflation factor of 1.5%. OPG's calculations are set out in Chart 1, below.

Chart 1

Year	Inputs and Assumptions										
	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Composite Index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2016	116.4	116.3	116.8	117.5	116.75			973.56			
2017	118	118.5	118.2	119	118.43	1.4%	88%	992.55	1.9%	12%	1.5%

3) X Factor (Productivity and Stretch Factors)

The OEB has approved a productivity factor of 0%⁷ and a stretch factor of 0.3%⁸ for the regulated hydroelectric facilities for the IR Term (2017-2021).

Based on the approved 2018 HPA, and using the inflation and X-factors summarized above, OPG estimates the 2019 HPA to be \$42.55/MWh. If the OEB's published index values include different annual percentage changes in either of the GDP-IPI FDD or the Ontario AWE, OPG will update this Application and the proposed 2019 HPA accordingly.

4.0 IMPLEMENTATION

OPG requests OEB approval of an effective date, and implementation date, of January 1, 2019 for the 2019 HPA.

⁷ EB-2016-0152 Decision, p. 128.

⁸ EB-2016-0152 Decision, p. 129.

CUSTOMER IMPACTS

1.0 PURPOSE

This evidence describes the impact of the proposed payment riders on a residential electricity consumer consuming at the 750 kWh per month level (the “typical residential customer”) and typical large industrial customers and medium/large business customers.

2.0 CUSTOMER IMPACTS

OPG has estimated the impact on customers in a manner that is consistent with previous OPG proceedings, based on the incremental annual changes in OPG’s weighted average total payments¹ that would result from the 2019-2021 deferral and variance account payment riders (Hydroelectric Payment Rider C and Nuclear Payment Rider C, per Ex. H1-2-1) and the 2019 hydroelectric payment amount (Ex. I1-1-1) proposed in this Application. The changes in the weighted average total payments are applied to the typical residential customer’s usage of OPG generation, after adjusting for line losses and accounting for OPG’s share of the province’s generation.²

Typical residential consumption is 789 kW, based on the monthly consumption (750kWh) used in the OEB “Bill Calculator” for estimating monthly electricity bills (using Time of Use pricing), increased to include line losses (using an assumed factor of 1.0525). OPG runs the “Bill Calculator” on the OEB’s website at: <https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator> for all local distribution companies available in the bill calculator and uses a simple average of all of the bills as the typical bill. The typical residential customer bill based on information updated as of May 2018 is \$112.84/month.

As described in Ex. I1-1-1, OPG has calculated the 2019 hydroelectric payment amount (“HPA”) to be \$42.55/MWh using an estimated escalation of 1.2%, which reflects the approved X-factor value of 0.3% and an estimated inflation factor value of 1.5% based on current Statistics Canada data tables for 2017 and OEB published index values for 2016. Consistent with the approach

¹ As set out in the EB-2016-0152 Payment Amounts Order (“EB-2016-0152 PAO”), Appendix I, Table 2, line 11.

² Based on forecast demand for 2019 (134.0 TWh) from Table 3.1 of IESO 18-Month Outlook Update for July 2018 to December 2019, published June 20, 2018.

1 used to estimate customer bill impacts in EB-2016-0152³, OPG has applied this 1.2% estimated
2 escalation factor to calculate an updated illustrative HPA for 2020 and 2021, as a proxy for
3 price-cap escalation in future years.⁴

4
5 As shown in Table 1, OPG estimates the average incremental impact of the proposed payment
6 riders and 2019 HPA on a typical residential customer's monthly bill to be \$0.39, or 0.34%, per
7 year over the 2019-2021 period. The proposed 2019-2021 deferral and variance account
8 payment riders comprise \$0.36 per year of this average annual bill impact and the 2019 HPA
9 comprises the remaining \$0.03.⁵

10
11 As the proposed deferral and variance account riders would begin to recover the December 31,
12 2017 account balances on a straight-line basis effective January 1, 2019, the total incremental
13 customer bill impact of the Application would be largely reflected in 2019, with relatively level or
14 decreasing annual customer bill impacts in the following two years.⁶

15
16 Using the same approach as in the EB-2016-0152 PAO, Appendix I, the estimated customer
17 bill impact of the proposed payment riders and 2019 HPA for medium/large businesses and
18 large industrial customers in the Alectra (PowerStream), Hydro One Networks Inc. and Toronto
19 Hydro-Electric System Limited service areas for the January 1, 2019 to December 31, 2021
20 period are provided in Ex. I1-1-2, Tables 1B, 1 C and 1D.⁷

³ EB-2016-0152 PAO, Appendix B, Table 1, Notes 1 and 2.

⁴ As noted in Ex. I1-1-1, OPG will update the Application to reflect index values for 2019 rates applications, typically published by the OEB in the fall of the preceding year, if they differ from the annual sub-index changes used by OPG in Ex. I1-1-1. If such an update is required, OPG will similarly update the illustrative HPA for 2020 and 2021 used to calculate customer bill impacts resulting from the proposals in this Application.

⁵ As required by Ontario Regulation 53/05, the weighted average payment amount calculation and resulting rate smoothing deferral amounts approved in EB-2016-0152 reflect a forecast HPA increase of 0.9% per year for 2019-2021 (EB-2016-0152 PAO, Appendix I, p. 10). This forecast increase was based on the 2018 price-cap index value. The estimated average incremental customer bill impact of \$0.03 in this Application is attributable to the difference between the higher price-cap index value of 1.2% for the 2019 HPA and the illustrative HPA for 2020 and 2021, and 0.9% used in the EB-2016-0152 PAO.

⁶ As shown at Ex. I1-1-2, Table 1, line 4, the estimated average annual impact of \$0.39 on a typical residential customer's monthly bill over the 2019-2021 period is comprised of an increase of \$1.39 in 2019, an increase of \$0.06 in 2020 and a decrease of \$0.29 in 2021. The reduction in 2021 is driven primarily from the lower proposed payment riders reflecting the previously approved end of the recovery period for the Pension and OPEB Cost Variance Account (Post 2012 Additions) as of June 30, 2021.

⁷ These are the same service areas presented for such customers in EB-2016-0152.

Numbers may not add due to rounding.

Table 1
Annualized Residential Consumer Impact

Line No.	Description	Note	2019	2020	2021	Average
			(a)	(b)	(c)	(d)
1	Typical Consumption (kWh/Month)	1	789	789	789	
2	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 10)		424	414	403	
3	Typical Bill (\$/Month)	1	112.84	112.84	112.84	
4	Incremental Bill Impact (\$/month) (line 2 x line 7 / 1000)		1.39	0.06	(0.29)	0.39
5	Incremental Bill Impact (%) (line 4 / line 3)		1.2%	0.1%	-0.3%	0.34%
6	Incremental Weighted Average Total Payments (\$/MWh)	2	3.28	3.42	2.71	
7	Year-Over-Year Change in Incremental Weighted Average Total Payments (\$/MWh)		3.28	0.14	(0.71)	
8	Total OPG Regulated Production (TWh)	3	72.0	70.3	68.4	
9	Forecast of 2017 Provincial Demand (TWh)	4	134.0	134.0	134.0	
10	OPG Proportion of Consumer Usage (line 8 / line 9)		53.7%	52.5%	51.0%	

Notes:

- 1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: <https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator> - accessed in May 2018
Typical Consumption includes line losses (Assumed loss factor of 1.052).
- 2 Per Ex. I1-1-2, Table 2, line 13.
- 3 EB-2016-0152, PAO App. I, Table 2, line 3 plus line 6.
- 4 Based on forecast demand for 2019 (134.0 TWh) from Table 3.1 of IESO 18-Month Outlook Update for July 2018 to December 2019, published June 20, 2018.

Numbers may not add due to rounding.

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Tab 1
Schedule 2
Table 1b

Table 1b
Annualized Bill Impact for Typical Alectra (PowerStream) Consumers

Line No.	Description	Note	2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)
1	Typical Consumer Usage (kWh/Month)	1	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600
2	Total Forecast Production (TWh)	2	72.0	72.0	70.3	70.3	68.4	68.4
3	OPG Portion of Consumer Usage	3	53.7%	53.7%	52.5%	52.5%	51.0%	51.0%
4	Consumer Usage of OPG Generation (kWh/Month) (line 1 x line 3)		44,470	1,556,434	43,438	1,520,317	42,220	1,477,695
5	Typical Monthly Consumer Bill (\$)	1	14,157	467,845	14,157	467,845	14,157	467,845
6	Year-Over-Year Change in Incremental Weighted Average Total Payments (\$/MWh)	4	3.28	3.28	0.14	0.14	(0.71)	(0.71)
7	Percentage Increase in Consumer Bills (line 6 x (line 4/1000) / line 5)		1.03%	1.09%	0.04%	0.05%	-0.21%	-0.22%
8	Dollar Increase in Consumer Bills (\$) (line 5 x line 7)		145.89	5,106.16	6.20	216.86	(29.94)	(1,047.78)

- Notes:
- 1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Powerstream EB-2015-0003 Draft Rate Order.
Medium/Large Business (EB-2015-0003 Draft Rate Order, Schedule B, Page 4): GS > 50 customer, consumption 80,000 kWh, loss factor 3.45%.
Large Industrial (EB-2015-0003 Draft Rate Order, Schedule B, Page 5): Large User customer, consumption 2,800,000 kWh, loss factor 3.45%.
 - 2 Per Ex. I1-1-2, Table 2, line 5 plus line 10.
 - 3 Per Ex. I1-1-2, Table 1, line 10.
 - 4 Per Ex. I1-1-2, Table 1, line 7.

Numbers may not add due to rounding.

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Exhibit I1
Tab 1
Schedule 2
Table 1c

Table 1c
Annualized Bill Impact for Typical Hydro One Networks Consumers

Line No.	Description	Note	2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)
1	Typical Consumer Usage (kWh/Month)	1	37,135	517,000	37,135	517,000	37,135	517,000
2	Total Forecast Production (TWh)	2	72.0	72.0	70.3	70.3	68.4	68.4
3	OPG Portion of Consumer Usage	3	53.7%	53.7%	52.5%	52.5%	51.0%	51.0%
4	Consumer Usage of OPG Generation (kWh/Month) (line 1 x line 3)		19,954	277,800	19,491	271,354	18,944	263,746
5	Typical Monthly Consumer Bill (\$)	1	7,556	77,516	7,556	77,516	7,556	77,516
6	Year-Over-Year Change in Incremental Weighted Average Total Payments (\$/MWh)	4	3.28	3.28	0.14	0.14	(0.71)	(0.71)
7	Percentage Increase in Consumer Bills (line 6 x (line 4/1000) / line 5)		0.87%	1.18%	0.04%	0.05%	-0.18%	-0.24%
8	Dollar Increase in Consumer Bills (\$) (line 5 x line 7)		65.46	911.37	2.78	38.71	(13.43)	(187.01)

Notes:

- 1 Current Approved Rates and Usage (adjusted for line losses) are based on 2017 bill impacts per Hydro One's EB-2016-0081 Draft Rate Order.
Medium/Large Business (EB-2016-0081 Draft Rate Order, Exhibit 6.0): GSd customer, consumption 35,000 kWh, loss factor 6.1%.
Large Industrial (EB-2016-0081 Draft Rate Order, Exhibit 6.0): ST customer, consumption 500,000 kWh, loss factor 3.4%.
- 2 Per Ex. I1-1-2, Table 2, line 5 plus line 10.
- 3 Per Ex. I1-1-2, Table 1, line 10.
- 4 Per Ex. I1-1-2, Table 1, line 7.

Table 1d
Annualized Bill Impact for Typical Toronto Hydro Consumers

Line No.	Description	Note	2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)
1	Typical Consumer Usage (kWh/Month)	1	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150
2	Total Forecast Production (TWh)	2	72.0	72.0	70.3	70.3	68.4	68.4
3	OPG Portion of Consumer Usage	3	53.7%	53.7%	52.5%	52.5%	51.0%	51.0%
4	Consumer Usage of OPG Generation (kWh/Month) (line 1 x line 3)		83,630	2,463,208	81,690	2,406,049	79,399	2,338,595
5	Typical Monthly Consumer Bill (\$)	1	27,003	771,057	27,003	771,057	27,003	771,057
6	Year-Over-Year Change in Incremental Weighted Average Total Payments (\$/MWh)	4	3.28	3.28	0.14	0.14	(0.71)	(0.71)
7	Percentage Increase in Consumer Bills (line 6 x (line 4/1000) / line 5)		1.02%	1.05%	0.04%	0.04%	-0.21%	-0.22%
8	Dollar Increase in Consumer Bills (\$) (line 5 x line 7)		274.36	8,080.99	11.65	343.21	(56.30)	(1,658.21)

Notes:

1

Current Approved Rates and Usage (adjusted for line losses) are taken from the THESL EB-2014-0116 Draft Rate Order
Medium/Large Business (EB-2014-0116 Draft Rate Order, Schedule 9, Page 7): GS 50-999 customer, consumption 150,000 kWh, loss factor 3.76%
Large Industrial (EB-2014-0116 Draft Rate Order, Schedule 9, Page 9): Large Use customer, consumption 4,500,000 kWh, loss factor 1.87%

2

Per Ex. I1-1-2, Table 2, line 5 plus line 10.

3

Per Ex. I1-1-2, Table 1, line 10.

4

Per Ex. I1-1-2, Table 1, line 7.

Numbers may not add due to rounding.

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Tab 1
Schedule 2
Table 2

Table 2
Computation of OPG Weighted Average Payment Amount and Total Payments

Line No.	Description	Note	2018	2019	2020	2021
			(a)	(b)	(c)	(d)
1	Hydroelectric Payment Amount (\$/MWh)	1	42.05	42.55	43.07	43.58
2	Hydroelectric Payment Rider A (\$/MWh)	2	0.52	1.44	1.01	0.00
3	Hydroelectric Payment Rider B (\$/MWh) (Hydroelectric Interim Period Shortfall Recovery Rider)	3	0.13	0.35	0.24	0.00
4	Hydroelectric Payment Rider C (\$/MWh)	4	0.00	1.65	1.65	1.56
5	Hydroelectric Production Forecast (TWh)	5	33.0	33.0	33.0	33.0
6	Nuclear Payment Amount (NPA) (\$/MWh)	6	78.64	77.00	85.00	89.70
7	Nuclear Payment Rider A (NPR) (\$/MWh)	7	1.05	2.79	2.04	0.00
8	Nuclear Payment Rider B (\$/MWh) (Nuclear Interim Period Shortfall Recovery Rider)	8	2.88	7.71	5.64	0.00
9	Nuclear Payment Rider C (\$/MWh)	9	0.00	4.55	4.76	3.43
10	Nuclear Production Forecast (TWh)	10	38.5	39.0	37.4	35.4
11	Weighted Average Total Payments (\$/MWh) ((Sum lines 1 to 4) x line 5) + (Sum lines 6 to 9) x line 10) / (line 5 + line 10)		64.16	70.96	73.31	69.98
12	EB-2016-0152 Weighted Average Total Payments (\$/MWh)	11	64.16	67.68	69.88	67.27
13	Incremental Weighted Average Total Payments (\$/MWh) (line 11 - line 12)		0.00	3.28	3.42	2.71
14	Percentage Change in Weighted Average Payment Amount (Year over Year)	12	5.0%	10.6%	3.3%	-4.5%

Notes

- Col. (a) is the OEB approved 2018 hydroelectric payment amount per EB-2016-0152, PAO App. B, Table 1, line 6.
Col. (b) is the 2019 hydroelectric payment amount requested for approval in this application.
Cols. (c) and (d) are illustrative hydroelectric payment amounts calculated using an annual adjustment to the hydroelectric rate of 1.2%.
- Cols. (a) to (c) are EB-2016-0152 approved hydroelectric riders per PAO App. D, Table 1, line 14.
- Regulated Hydroelectric interim period shortfall recovery rider per EB-2016-0152 PAO App. F, Table 1, lines 17 to 19.
- Cols. (b) to (d) per Ex. H1-2-1, Table 1, cols. (e), (f) and (g), line 17.
- Regulated Hydroelectric production is the 2014 and 2015 average OEB approved hydroelectric production per EB-2013-0321 Decision and Order P. 9, and EB-2016-0152 PAO, App. I, Table 2, line 3.
- Cols. (a) to (d) are the OEB-approved nuclear payment amounts per EB-2016-0152 PAO, App. C, Table 1.
- Cols. (a) to (c) are EB-2016-0152 approved nuclear riders per PAO App. E, Table 1, line 18.
- Nuclear interim period shortfall recovery rider per EB-2016-0152 PAO App. F, Table 2, lines 12 to 14.
- Cols. (b) to (d) per Ex. H1-2-1, Table 2, cols. (e), (f) and (g), line 23.
- Cols. (a) to (d) are production amounts approved in EB-2016-0152, per EB-2016-0152 PAO App. C, Table 1, line 2.
- Per EB-2016-0152 PAO App. I, Table 2, line 11.
- Col. (a) per EB-2016-0152 PAO App. I, Table 2, col. (c), line 12.