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November 28, 2018

Via RESS and In Person

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli,

RE: EB-2018-0243 – Ontario Power Generation Inc. – Application for 2019 Hydroelectric Payment Amount Adjustment and Clearance of Deferral and Variance Account Balances

Enclosed are updates to Ex. I1-1-1, Ex. I1-1-2, Ex. I1-1-2 Tables 1, 1b, 1c, 1d and 2, L-H-CCC-5 Attachment 1, and L-H-Staff-8 to reflect the OEB published StatsCan index values. In addition, OPG is also enclosing corrections to Ex. A1-2-1 and Ex. H1-1-1 for clarification purposes. A description of the updated material is provided below.

Exhibit	Description of the Change
Ex. A1-2-1, p. 2, line 19	Clarification to calculation.
Ex. H1-1-1, p. 1, line 8 and p. 15, line 26	Removal of inapplicable reference (p. 1) and correction to typographical error (p. 15).
Ex. H1-1-1, Tables 9a and 14	Correction to formula description (Table 9a) and clarifications of table labeling and correction of footnote numbering (Table 14).
Ex. I1-1-1 Ex. I1-1-2 Ex. I1-1-2 Tables L-H-Staff-8	OPG estimate of I factor replaced with OEB published StatsCan index values. I-Factor reduced from 1.5% to 1.4%. Residential average monthly bill impact reduced from $0.39/month to $0.38/month. OPG has also removed all references to updating its application with the published StatsCan index values once published.
L-H-CCC-5 Attachment 1	Updated for OEB published StatsCan index values plus correction to typographical error for hydro rider C in 2021.

OPG has submitted these documents through the Regulatory Electronic Submissions System and is providing nine (9) paper copies. This material will also be available on OPG's website at www.opg.com.

Should you have any questions or concerns please contact the undersigned.

Yours truly

[Original Signed By]

Saba Zadeh

c: Charles Keizer (Torys) via email
Mel Hogg (OPG) via emai

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.

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

6. OPG seeks to recover the amounts described in paragraph 4 above, less amounts previously approved for recovery through payment riders established in EB-2016-0152, over a three-year period from January 1, 2019 through December 31, 2021, except for the previously approved balance of the Pension and OPEB Cost Variance Account, the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and the income tax impacts associated with the recovery of that balance, and the balance of the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub Account. OPG proposes to recover the December 31, 2017 audited balance of the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the income tax impacts associated with the recovery of that balance, over an eight-year period from January 1, 2018 to December 31, 2026.[2] The first three years of that recovery period are reflected in the payment riders proposed in this Application. OPG seeks to recover the previously approved December 31, 2017 audited balances in the Pension and OPEB Cost Variance Account, less amounts previously approved for recovery through payments riders established in EB-2016-0152, over recovery periods previously authorized by the OEB.[3]

7. To disposition the balances in the deferral and variance accounts, and income tax impacts associated with the recovery of the balance in the Pension & OPEB Cash versus Accrual Differential Deferral Account, as described above, OPG is seeking payment riders for the output of the regulated hydroelectric facilities of $1.65/MWh for the period from January 1, 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.

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

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

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

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

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

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

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

(a)	The applicant:	Saba Zadeh Director, Regulatory Affairs Ontario Power Generation Inc.
	Mailing address:	HLC 700 University Avenue Toronto ON M5G 1X6
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(b)	The applicant's Counsel:	Charles Keizer Torys LLP
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(c) The applicant’s Counsel: Mel Hogg
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Dated at Toronto, Ontario, this 9th day of August, 2018.

Ontario Power Generation Inc.

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Charles Keizer
Torys LLP

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.

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 $288.9M[2] for the regulated hydroelectric facilities and $1,198.6M[3] for the nuclear facilities.[4] Adjusted for the 2018-2020 amortization amounts approved in EB-2016-0152, these balances are $205.4M[5] for the regulated hydroelectric facilities and $911.6M[6] 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.

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

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

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

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

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

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

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

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

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

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

Hydroelectric ancillary revenues in 2016 and 2017 were higher than the reference amounts that reflect the forecasts underpinning the revenue requirement approved in EB-2013-0321, primarily due to higher regulation service revenue and operating reserve revenue, partially offset by lower reactive support revenue. These factors resulted in credit entries to the 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-

Nuclear ancillary revenues in January 1, 2016 through May 31, 2017 were lower than the reference amount that reflected the forecasts underpinning the revenue requirement approved in EB-2013-0321, mainly due to lower reactive support revenue. Similarly, reactive support revenue resulted in lower nuclear ancillary revenues than the reference amount that reflected the forecast underpinning the 2017 revenue requirement approved in EB-2016-0152, for June 1, 2017 through December 31, 2017. These factors resulted in debit entries to the Nuclear Sub Account of $1.3M in 2016 and $1.1M in 2017.[12]

5.3 Hydroelectric Incentive Mechanism Variance Account

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

There were no additions to the account for 2016 or 2017 as actual HIM revenues of $14.0M in 2016 and $12.4M in 2017 were significantly below the specified threshold of $54.5M[13], as shown in Ex. H1-1-1 Table 4.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

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

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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

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

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

5.5 Income and Other Taxes Variance Account

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

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

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

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

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

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

[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.

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[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 hydroelectric[21] and $128.8M for nuclear[22]; 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 hydroelectric[23] and $282.7M for nuclear[24].

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).

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

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

5.10 Pension & OPEB Cash Payment Variance Account

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

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

RPP contributions attributed to the prescribed facilities for June 1, 2017 through December 31, 2017 were lower than the reference amounts that reflect the forecast underpinning the revenue requirement approved in EB-2016-0152, reflecting the results of a subsequent actuarial valuation of the RPP as of January 1, 2017 filed with the Financial Services Commission of Ontario ("FSCO") in September 2017. The 2017 valuation resulted in a reduction in minimum required contributions relative to the 2016 valuation that underpinned the EB-2016-0152 forecasts, primarily due to lower going concern special payments. OPEB payments attributed to the prescribed facilities for the period were largely unchanged from the reference amounts.

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

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

5.11 Pension and OPEB Cash Versus Accrual Differential Variance Account

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

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

[25] Attachment 3, pp. 9-10.

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

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

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

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

[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.

year-end 2016 plan obligations, reflected through an actuarial gain recorded at the end of 2016.[31]

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

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

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

Actual OPEB costs increased from 2016 to 2017. This reflected the reduction in 2016 costs due to the LTD actuarial gain and the effect of lower discount rates as at December 31, 2016 used to determine the 2017 OPEB costs, partially offset by the impact of lower expected per capita health care benefit costs reflecting lower costs of prescription drugs as part of the 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.

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

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

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

No interest was recorded in the account in 2016 or 2017, pursuant to the corresponding 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.

The account has two sub-accounts described below:

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

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

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

Variances recorded in the non-derivative sub-account are determined by comparing the rate of recovery for Bruce revenues net of costs reflected in the corresponding payment amounts order multiplied by OPG's actual nuclear production, and OPG's actual Bruce revenues net of costs. A rate of recovery of $0.84/MWh was used to calculate sub-account entries for January 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).

derivation of the 2016 debit entry of $143.0M to the Non-Derivative Sub-Account and the 2017 debit entry of $23.3M is shown in Ex. H1-1-1 Table 12.[37] A comparison of Bruce revenues net of costs is presented in Ex. H1-1-1 Table 12a.

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

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

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[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.

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

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

5.18 SR&ED ITC Variance Account

The SR&ED ITC Variance Account was approved in EB-2016-0152, as of the effective date of the EB-2016-0152 PAO. The account records 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.

Actual SR&ED ITCs net of tax (attributed to the nuclear facilities) recorded in 2017 were higher than the reference amount that reflected the forecast underpinning the 2017 revenue requirement approved in EB-2016-0152. The derivation of the resulting credit entry of $3.4M 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

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

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 line 5, less line 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.

Numbers may not add due to rounding.

Table 14

Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account [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	**Lesser of ARC and UNL**	2	(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**	3	(30.5)	(12.6)
5	**Non-Asset Retirement Costs**	4	(4.4)	(1.8)
6	**Total Depreciation Expense Impact** (line 4 + line 6)		(34.9)	(14.5)
	Variable Expenses:			
7	**Used Fuel Storage and Disposal Variable Expenses**	5, 6	5.0	0.0
8	**Low & Intermediate Level Waste Management Variable Expenses**	5, 6	0.1	0.0
9	**Total Variable 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	**Return on Rate Base - 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 Revenue Requirement Impact** (line 3 + line 6 + line 9 + line 18)		(71.2)	(32.1)
20	**Revenue Requirement Impact of Non-ARC Depreciation** (line 2 + line 5 + line 12)		(5.8)	(2.4)
21	**Revenue Requirement Impact Excluding Non-ARC Depreciation** (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.

2019 HYDROELECTIC 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 published by the OEB in the fall of 2018. 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/MWh[1], 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%."[2]

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 EB-2016-0152 Decision established the formula to be applied to adjust rates annually, the base

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[1] EB-2016-0152 PAO, p. 9, paragraph 3.
[2] *Ibid*.

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 follows[3]:

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

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.[4]

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):[5]

   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%) x GDP-IPI FDD] + [12% x Ontario AWE]

   The OEB published the 2017 GDP-IPI FDD and Ontario AWE sub-indices on November 23, 2018. An inflation factor of 1.4% is determined using the OEB published sub-indices for 2016 and 2017 and the OEB approved weighting of these indices, as illustrated in Chart 1, below.

[3] EB-2016-0152 Decision, p. 121.
[4] EB-2016-0152 PAO, p. 9, paragraph 3.
[5] EB-2016-0152 Decision, p. 122.

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	116.5	116.4	116.9	117.5	116.83			973.55			
2017	118	118.5	118.2	119	118.43	**1.4%**	**88%**	992.55	**1.9%**	**12%**	**1.4%**

3) **X Factor (Productivity and Stretch Factors)**

The OEB has approved a productivity factor of 0%[6] and a stretch factor of 0.3%[7] 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, the 2019 HPA is to be $42.51/MWh.

4.0 IMPLEMENTATION

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

[6] EB-2016-0152 Decision, p. 128.
[7] 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 determined 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 payments[1] 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 $42.51/MWh using an escalation of 1.1%, which reflects the approved X-factor value of 0.3% and an estimated inflation factor value of 1.4% based on OEB published index values for 2016 and 2017. Consistent with the approach used to estimate customer bill impacts in EB-

[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.

2016-0152[3], OPG has applied this 1.1% estimated escalation factor to calculate an updated illustrative HPA for 2020 and 2021, as a proxy for price-cap escalation in future years.

As shown in Table 1, OPG estimates the average incremental impact of the proposed payment riders and 2019 HPA on a typical residential customer's monthly bill to be $0.38, or 0.34%, per year over the 2019-2021 period. The proposed 2019-2021 deferral and variance account payment riders comprise $0.36 per year of this average annual bill impact and the 2019 HPA comprises the remaining $0.02.[4]

As the proposed deferral and variance account riders would begin to recover the December 31, 2017 account balances on a straight-line basis effective January 1, 2019, the total incremental customer bill impact of the Application would be largely reflected in 2019, with relatively level or decreasing annual customer bill impacts in the following two years.[5]

Using the same approach as in the EB-2016-0152 PAO, Appendix I, the estimated customer bill impact of the proposed payment riders and 2019 HPA for medium/large businesses and large industrial customers in the Alectra (PowerStream), Hydro One Networks Inc. and Toronto Hydro-Electric System Limited service areas for the January 1, 2019 to December 31, 2021 period are provided in Ex. I1-1-2, Tables 1B, 1 C and 1D.[6]

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

[4] 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 $0.02 in this Application is attributable to the difference between the higher price-cap index value of 1.1% for the 2019 HPA and the illustrative HPA for 2020 and 2021, and 0.9% used in the EB-2016-0152 PAO.

[5] 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.

[6] 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)		1.38	0.05	(0.29)	0.38
5	**Incremental Bill Impact (%)** (line 4 / line 3)		1.2%	0.0%	-0.3%	0.34%
6	Incremental Weighted Average Total Payments ($/MWh)	2	3.26	3.38	2.65	
7	Year-Over-Year Change in Incremental Weighted Average Total Payments ($/MWh)		3.26	0.12	(0.73)	
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.

Table 1b

Annualized Bill Impact for Typical Alectra (PowerStream) Consumers

Line No.	Description	Note	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 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	3.26	3.26	0.12	0.12	(0.73)	(0.73)
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		1.02%	1.09%	0.04%	0.04%	-0.22%	-0.23%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		145.03	5,076.18	5.30	185.50	(30.88)	(1,080.84)

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.

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

Line No.	Description	Note	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 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	3.26	3.26	0.12	0.12	(0.73)	(0.73)
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		0.86%	1.17%	0.03%	0.04%	-0.18%	-0.25%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		65.08	906.02	2.38	33.11	(13.86)	(192.91)

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.

Numbers may not add due to rounding.

Table 1d
Annualized Bill Impact for Typical Toronto Hydro Consumers

Line No.	Description	Note	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 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	3.26	3.26	0.12	0.12	(0.73)	(0.73)
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		1.01%	1.04%	0.04%	0.04%	-0.22%	-0.22%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		272.75	8,033.55	9.97	293.58	(58.08)	(1,710.54)

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.

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 ($/MWh)**	1	42.05	42.51	42.98	43.45
2	**Hydroelectric Payment Rider A ($/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 ($/MWh)** ((Sum lines 1 to 4) x line 5) + (Sum lines 6 to 9) x line 10)) / (line 5 + line 10)		64.16	70.94	73.27	69.92
12	**EB-2016-0152 Weighted Average Total Payments ($/MWh)**	11	64.16	67.68	69.88	67.27
13	**Incremental Weighted Average Total Payments ($/MWh)** (line 11 - line 12)		0.00	3.26	3.38	2.65
14	**Percentage Change in Weighted Average Payment Amount (Year over Year)**	12	5.0%	10.6%	3.3%	-4.6%

Notes
1 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 1.1%.
2 Cols. (a) to (c) are EB-2016-0152 approved hydroelectric riders per PAO App. D, Table 1, line 14.
3 Regulated Hydroelectric interim period shortfall recovery rider per EB-2016-0152 PAO App. F, Table 1, lines 17 to 19.
4 Cols. (b) to (d) per Ex. H1-2-1, Table 1, cols. (e), (f) and (g), line 17.
5 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.
6 Cols. (a) to (d) are the OEB-approved nuclear payment amounts per EB-2016-0152 PAO, App. C, Table 1.
7 Cols. (a) to (c) are EB-2016-0152 approved nuclear riders per PAO App. E, Table 1, line 18.
8 Nuclear interim period shortfall recovery rider per EB-2016-0152 PAO App. F, Table 2, lines 12 to 14.
9 Cols. (b) to (d) per Ex. H1-2-1, Table 2, cols. (e), (f) and (g), line 23.
10 Cols. (a) to (d) are production amounts approved in EB-2016-0152, per EB-2016-0152 PAO App. C, Table 1, line 2.
11 Per EB-2016-0152 PAO App. I, Table 2, line 11.
12 Col. (a) per EB-2016-0152 PAO App. I, Table 2, col. (c), line 12.

H-Staff-8

Interrogatory

Reference:
Exhibit F1/Tab 1/Schedule 1

Reference:
EB-2016-0152 Decision and Order, December 28, 2017

As part of the OEB's Decision and Order in EB-2016-0152, the OEB stated:

> It is the OEB's expectation that OPG will file an application comprising the disposition of the next set of deferral and variance accounts, including OPG's proposal for the pension and OPEB Cash vs. Accrual Differential account (**that will address with detailed evidence OPG's proposal for the accounting method to be used going forward**), at the same time as the implementation of the 2019 hydroelectric payment amounts.[1]
>
> [1] EB-2016-0152 Decision and Order, page 160, December 28, 2017

Please provide the evidence references that complies with the EB-2016-0152 Decision and Order. In the event that further information is required, please file the additional information.

Response

Exhibit F1-1-1 sets out OPG's pre-filed evidence for proposed recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account ("Interim Account") and for the proposed regulatory accounting method to be used going forward for pension and OPEB costs. At Ex. F1-1-1, p. 7, lines 14-25, OPG's pre-filed evidence states:

> Consistent with this application, the payment amounts proposed in OPG's future cost-based rates applications would reflect pension and OPEB costs calculated pursuant to the accrual accounting method, in accordance with the Report.
>
> OPG has made extensive submissions that consistently support the continued use of the accrual accounting method for recovery of pension and OPEB costs, both in EB-2013-0321 and EB-2015-0040. Given the OEB's findings that the accrual accounting method is presumptively appropriate for pension and OPEB costs, that OPG was not transitioned away from the accrual basis of recovery, and that utilities remaining on the accrual basis are not required to justify the use of that method, OPG has not re-iterated those submissions in this evidence.

At footnote 28 of Ex. F1-1-1, OPG provided references to its detailed submissions in EB-2015-0040 in support of the accrual accounting method,[1] as well as OPG's final arguments in EB-2013-0321. While OPG did not believe it would be helpful to reiterate its submissions on this issue in the pre-filed evidence for this application for the above noted reasons, OPG has summarized its main relevant submissions from the EB-2015-0040 and EB-2013-0321 proceedings below, with updates to information previously provided where appropriate. Below, OPG also discusses the forecast of pension and OPEB costs and cash amounts it has filed in response to Ex. L-H-Staff-12.

By way of background, the OEB approved the accrual-based methodology for determining OPG's pension and OPEB-related costs for setting payment amounts in EB-2007-0905 and EB-2010-0008, prior to temporarily setting rates using cash amounts in EB-2013-0321 pending the outcome of the generic consultation on the matter (EB-2015-0040). As proposed by OPG given that the generic consultation was in progress, the OEB continued this temporary measure in setting OPG's most recent payment amounts in EB-2016-0152. OPG continued to file a forecast of pension and OPEB accrual costs and supporting evidence in the EB-2016-0152 proceeding.[2]

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[1] EB-2015-0040 Initial Written Submissions on the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs, dated July 31, 2015 ("OPG 2015 Submission"); Pension & OPEB Stakeholder Forum Presentation, dated July 19, 2016; and Submission on Pension and OPEB Cost Recovery, dated September 22, 2016 ("OPG 2016 Submission").
[2] EB-2016-0152 Ex. F4-3-2, sections 5.0 and 5.1, as updated at Ex. N1-1-1, section 3.1.2.1.

OPG's pension and OPEB accrual costs for the regulated facilities, including those in respect of the balances in question in this proceeding, have been determined in a consistent manner in every OPG proceeding since EB-2007-0905, in accordance with generally accepted accounting principles applicable to OPG and generally accepted actuarial practice. As it is in this proceeding,[3] OPG's pension and OPEB cost information filed with the OEB is supported by an independent actuary's reports.

OPG's pension and OPEB accrual costs and obligations continue to be determined annually by independent actuaries using management's best estimate assumptions in accordance with US GAAP. Both economic (e.g., inflation, salary escalation, and health care cost trends) and demographic (e.g., mortality, termination rates, and retirement rates) assumptions are used. In accordance with US GAAP, the discount rates used in determining accrual costs and obligations continue to be based on a AA corporate bond yield curve. This approach was last outlined in detail in OPG's pre-filed evidence at EB-2016-0152 Ex. F4-3-2, sections 5.0 and 5.1 (as updated at Ex. N1-1-1, section 3.1.2.1). It is also the same basis that establishes the accrual costs underpinning the Interim Account balances, as set out at Ex. H1-1-1, section 5.11, as well as the forecast provided in Ex. L-H-Staff-12. OPG expects this approach to remain unchanged with respect to pension and OPEB accrual costs in future cost-based rate applications, and also expects to continue filing supporting actuarial evidence for its pension and OPEB costs.

Principles and Practices for Review of Pension and OPEB Recovery Methods

While the OEB did not adopt any new principles for the purposes of the EB-2015-0040 Report of the OEB on the Regulatory Treatment of Pension and OPEB Costs, dated September 14, 2017 ("Report"), it did reaffirm several existing regulatory principles and practices that would guide its approach to the treatment of pension and OPEB costs. These included fairness, minimizing intergenerational inequity, aligning regulatory treatment with financial accounting treatment where not inconsistent with sound rate-making principles and the setting of just and reasonable rates, and a consistent approach to pension and OPEB cost recovery over time for

[3] Ex. H1-1-1 Att. 3 and 4.

a given utility.[4] They also included minimizing rate volatility, appropriate allocation of risk, transparency and providing value to ratepayers.[5,6] Additionally, the OEB noted that transitioning between recovery methods may cause serious and difficult-to-resolve issues.[7]

Support for the Accrual Method of Recovery

Applying the accrual method to OPG's pension and OPEB costs:

(i) aligns OPG's rate recovery with required financial accounting and reporting standards;
(ii) is consistent with the principles of fairness, minimizing intergenerational inequity, and consistency;
(iii) promotes transparency and provides appropriate price signals to encourage efficient consumption; and
(iv) avoids adverse financial impacts and complex issues arising from transitioning away from the accrual basis of recovery.[8]

The Report notes that "accrual accounting is the method required for financial statement reporting purposes and is based on the underlying accounting standard for pension costs."[9] In accordance with such standards under US GAAP, OPG applies the accrual accounting methodology when preparing its financial statements, which are audited annually.[10] The Board approved OPG's use of US GAAP for regulatory purposes since EB-2012-0002 and has previously approved the recovery of payment amounts based on OPG's prior use of accrual

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[4] Report, pp. 3-4.
[5] Report, p. 4.
[6] With respect to minimizing rate volatility, as in EB-2015-0040, OPG's submissions continue to be that the principle may apply at different stages of the rate-setting process. For example, revenue requirement may increase due to rising costs in one area but be offset by decreases in another. Accordingly, OPG submitted that, in the context of a cost-base rate application, it would be appropriate to consider rate volatility based on a comprehensive revenue requirement rather than an individual component (OPG 2016 Submission, p. 8 and EB-2015-0040, OPG Submissions dated June 22, 2017 ("OPG 2017 Submission"), p. 7).
[7] Report, p. 9
[8] OPG 2016 Submission, pp. 4, 10, 32.
[9] Report, p. 5.
[10] As do three out of the four other major utilities with single employer defined benefit contribution pension plans regulated by the OEB (i.e. Hydro One Networks, Union Gas and Enbridge Gas Distribution).

accounting (under former Canadian GAAP).[11] As noted above, the Report reaffirmed the OEB's preference, previously articulated in the generic consultation on transition to International Financial Reporting Standards,[12] for regulatory accounting to follow financial accounting where not inconsistent with sound rate making principles.

On an accrual basis, pension and OPEB costs are incurred and recognized in accordance with generally accepted accounting principles when the related employee service is considered to be rendered and the benefit is considered to be earned, not when the actual benefit payments are made to retirees in the future, nor when the contributions to the pension plan are made by the employer.[13] It is the earning of the benefit which results in the cost being incurred, not its payment. As the Report notes, "[t]he cash method fails to consider the level of post-retirement benefits that a current employee has earned in a given year."[14,15] Therefore, reflecting the costs of these benefits to OPG in the payment amounts at the time they are earned results in the appropriate matching of costs and benefits, thereby avoiding intergenerational equity issues and ensuring fairness to both customers and the company.[16]

In accordance with the "just and reasonable" rates standard, OPG believes that the recovery of the current cost impacts that flow from OPG's pension and OPEB obligations attributable to the prescribed facilities should be allowed by the OEB. Accounting standards are designed to require entities to reflect the true cost of doing business in their financial statements, and their use for rate-making purposes promotes transparency in relation to the true cost of a regulated service such as electricity generation. As the OEB has said many times, it is in the public

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[11] EB-2013-0321, Argument in Chief, p. 95, lines 23 to 27 and p. 100, lines 18-22.
[12] EB-2008-0408, Report of the Board, p. 7.
[13] EB-2013-0321, Argument in Chief, p. 96, lines 1-5.
[14] Report, p. 7.
[15] As discussed by OPG in the generic consultation, with respect to registered pension plans, funding valuations of the plans pursuant to which employers make funding contributions are not intended to represent a utility's pension cost for a given period. Instead, the purpose of these valuations is to calculate the plan's funded status and required contribution range in line with legislative and regulatory requirements, with pension plan health and benefit security of members generally being the key considerations (OPG 2016 Submission, pp. 20, 22-23).
[16] EB-2013-0321, Argument-in-Chief, p.100, lines 5-7.

interest for consumers to know the true cost of electricity (or gas) so that they may make informed consumption decisions.

The application of the minimizing intergenerational equity and fairness principles indicates that ratepayers who are consuming electricity generated today should pay their fair share of the associated pension and OPEB costs for employee service that produced this electricity. The inter-generational inequity that would arise under a cash basis of recovery, especially for OPEB, is real and acute for a business like OPG, which is not required to replace assets that have reached end of life.[17] This is particularly true for OPG's nuclear plants, which are the majority of OPG's generation assets and have a fully variable rate.

The commercial operations at the Pickering station are currently planned to close by the end of 2024. Under a cash basis of recovery, this means that OPEB payments to employees who exit the organization (many of whom will immediately or eventually retire) after the Pickering generating station shuts down would be recovered as a cost of the Darlington station's generation. When the Darlington units eventually shut down at the end of their post-refurbishment life, OPEB payments to all retired nuclear employees will need be recovered as an additional cost of future generation and thus put pressure on future rates. Furthermore, while OPG's nuclear production from existing facilities as the nuclear plants reach end of life, the retiree population and associated benefits would be expected to increase.

Use of the accrual basis of recovery for OPG's pension and OPEB costs also provides for consistent treatment going back to the inception of OEB rate regulation of OPG's prescribed facilities in 2008. The OEB has previously noted the benefits of ensuring consistency in the context of OPG's pension and OPEB recovery in EB-2010-0008 and more generally in the Report, including stability and predictability in regulation, year-over-year comparability, and fairness to customers and the company.[18]

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[17] Unlike a transmission or distribution company, OPG is not a quasi-monopoly service provider with an obligation to serve that must constantly replace the assets used to meet this obligation.
[18] EB-2010-0008 Decision with Reasons, p. 91; Report, p. 8.

As OPG noted in its EB-2015-0040 submissions, the goal of efficient consumption through appropriate price signals in the context of pension and OPEB cost recovery needs to be balanced against other regulatory principles such as minimizing rate volatility.[19] Similarly, with respect to interim account balances such as OPG's, the Report noted that affected utilities may need to consider mitigation measures when disposing of significant balances.[20] Consistent with this, OPG has proposed that the Interim Account be recovered over an extended period of eight years, which reduces rate volatility and customer bill impacts. As noted at Ex. I1-1-2, p. 2, the recovery of all deferral and variance account balances as proposed by OPG would result in a relatively modest increase in the typical residential customer monthly bill of $0.36 per year, which, when combined with the $0.02 impact from the proposed increase to the hydroelectric base payment amount, represents a total increase of 0.34% per year.

Adverse Financial Consequences of Transition

In general, as the Report notes, "[t]he issues raised by transitioning between recovery methods may be serious and difficult to resolve fairly, whether transition from or to the accrual method."[21] The Report further indicates that a transition to a different method of recovery should only be warranted in a particular case if "a transition is necessary to set just and reasonable rates and the transition issues are manageable for that particular utility."[22] In OPG's case, additional complexities may arise on a transition away from the accrual methodology because O. Reg. 53/05 commenced OEB rate regulation a number of years after OPG was formed and requires acceptance of OPG's last audited asset and liability values prior to the OEB's setting of initial rates for prescribed assets.[23]

As discussed in EB-2015-0040 and EB-2013-0321, adoption of a cash basis of recovery for pension and OPEB costs would cause adverse financial consequences to OPG and its

[19] OPG 2016 Submission, p. 10.
[20] Report, p. 11.
[21] Report, p. 9.
[22] Ibid.
[23] OPG 2016 Submission, pp. 12 and 23-24.

shareholder, through material reductions in net income (discussed below).[24] In turn, this would add pressure to OPG's credit metrics and credit rating, negatively impact OPG's ability to earn its OEB-authorized rate of return, increase risk to the shareholder and ultimately reduce the value of the shareholder's investment in the company. The increase in OPG's risk profile could also increase costs to ratepayers through a higher equity ratio in the deemed capital structure or a higher cost of debt, for example.[25]

If the OEB were to order a move to a cash basis of recovery, this would result in an immediate write-off against current period's net income of the regulatory asset of $613M for the Interim Account balance (as of December 31, 2017) that presumably would not be allowed for recovery. Additionally, it would result in ongoing reductions in net income in respect of future OPEB cost recoveries, due to restrictions on establishment of regulatory assets for cash-to-accrual OPEB differences under US GAAP that are described in the KPMG report and OPG's submissions in EB-2015-0040.[26] For example, based on the forecast in Ex. L-H-Staff-12, these reductions would be in excess of $500M over the 2018-2024 period. Further future net income reductions and an economic loss would result in respect of future registered pension plan cost recoveries, equal to the amount by which OPG's pension contributions in the period prior to transitioning to the cash basis would have exceeded accrual costs.[27] As set out in OPG's EB-2015-0040 submissions, this future loss is estimated at approximately $700M, which is inclusive of the write-off the pension portion of the December 31, 2017 Interim Account balance.[28]

Pension and OPEB Cost Trends

While short-term differentials between cash amounts and accrual costs can and will continue to exist, OPG is of the view that a cost recovery methodology should be established with a long-term perspective based on the principles discussed above.

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[24] OPG 2016 Submission, pp. 12 and 23; OPG 2015 Submission, pp. 9-11, EB-2013-0321 Reply Argument, pp. 185-189.
[25] OPG 2015 Submission, p. 9.
[26] OPG 2016 Submission, pp. 12, 14-15. KPMG Report, pp. 72-76.
[27] OPG 2016 Submission, pp. 23-25.
[28] OPG's 2016 Submission, p. 24, footnote 32.

With respect to registered pension plan costs in particular, OPG outlined in EB-2013-0321 and EB-2015-0040 that neither the accrual method nor the alternatives considered in the generic consultation can be expected to produce consistently lower or more stable level of costs for inclusion in OPG's payment amounts, as multiple factors inherently impact differences between accounting and funding valuations.[29,30] For example, as shown in Chart 1 below, OPG's actual cash funding contributions have been higher than recoverable accrual costs (i.e., included in rates or recorded in deferral and varinace accounts) for the 2008-2012 period, lower than recoverable accrual costs in the 2013-2018 period, and are projected to be higher than accrual costs in the 2019-2024 period (per Ex. L-H-Staff-12). This trend is consistent with the Report's observation that there is no guarantee that the then-current trend of higher accrual costs compared to cash funding amounts would continue in the future.[31] In particular, the below chart shows that cash funding contributions attributed to the regulated facilities are projected to cumulatively exceed accrual costs by approximately $720M between 2018 and 2024, compared to approximately $360M by which accrual costs cumulatively exceeded cash funding contributions between 2008 and 2017.

[29] EB-2013-0321: Argument-in-Chief, p. 105 and Reply Argument, p. 179; OPG's 2016 Submission, pp. 28-29.
[30] In its submissions, OPG also explained that the cash funding method does not yield advantages over the accrual accounting method when it comes to governance and oversight matters or professional judgement used to determine the amounts. Both methods require the setting of forward-looking actuarial assumptions and both methods are subject to well-developed governance and independent oversight frameworks (through regulatory and professional bodies, and independent audit and legislative requirements, as applicable). (OPG 2016 Submission, pp. 25-28)
[31] Report, p. 6.

Chart 1: Accrual-to-Cash Differential for Pension Costs[32] ($M)

Cost Recovery Basis	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Accrual (Recoverable Costs)	121.4	141.4	150.1	195.0	286.1	383.3	440.0	482.7	339.9	221.3	252.6	105.6	78.2	55.7	37.8	21.4	20.5	3,333.0
Cash (Funding Contributions)	149.0	206.1	208.5	235.5	297.1	242.9	300.5	331.3	234.0	196.7	180.6	184.3	188.3	180.6	184.2	187.9	188.1	3,745.2
Accrual less Cash	(27.6)	(64.7)	(58.3)	(40.5)	(10.9)	140.3	139.5	151.4	105.9	24.6	72.1	(78.7)	(110.0)	(124.9)	(146.5)	(166.5)	(167.6)	(362.5)

While these projections are subject to inherent variability due to the impact of actuarial assumptions and economic and financial market conditions, they demonstrate that the recent years' decline in accrual costs is expected to conitnue into the future, while cash funding amounts are expected to levelize and remain relatively steady. By 2024, cash funding contributions are projected at approximately $190M, compared to accrual costs of approximately $20M (which is less than 5% of the accrual costs at their peak in 2014/2015). This forecast trend is partly underpinned by the fact that the recent years' decreases in OPG's cash funding contributions stemming from reductions in special payments toward the deficit, which has been fully eliminated per the most recent acturial valuation, will not be a factor in year-over-year decreases going forward.

As shown in Ex. L-H-Staff-12, the reversal of the accrual-to-cash differential trend for registered pension plan costs is expected to more than offset the accrual-to-cash differential for OPEB costs starting in 2019. By 2024, the combined pension and OPEB accrual costs are projected to be approximately $80M lower than the combined cash amounts (Nuclear and Regulated Hydroelectric).

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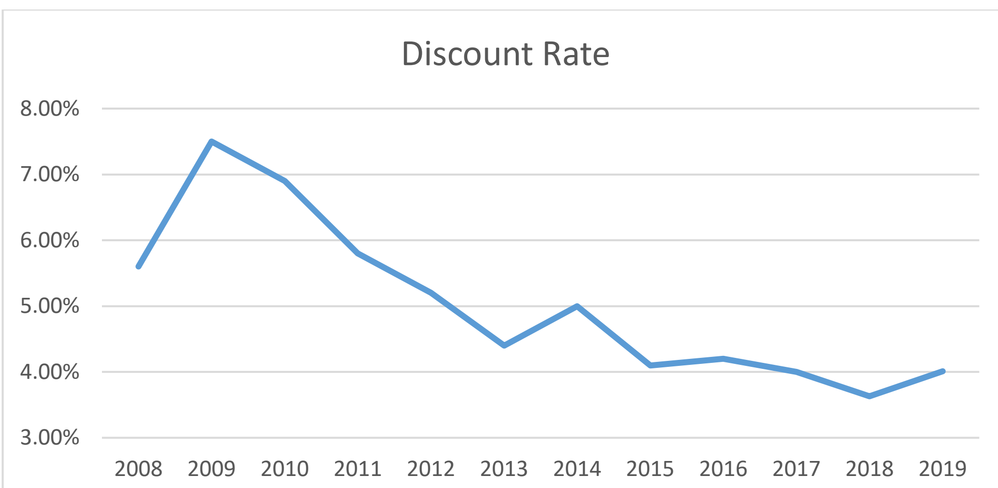
[32] Subject to below, 2008-2013 per EB-2013-0321 Argument-in-Chief, p. 105, Chart 4. 2015-2017 per Ex. H-1-1, Tables 7 and 7a, lines 4 and 8 (sum of Nuclear and Regulated Hydroelectric). 2018-2024 per Ex. L-H-Staff-12, Charts 5 and 6 (sum of Nuclear and Regulated Hydroelectric). 2008 represents the period from April 1, 2008 to December 31, 2008 and, for "Cash" and "Accrual less Cash" values, differs from EB-2013-0321 Argument-in-Chief, p. 105, Chart 4 that incorrectly used the full-year figure for 2008 "Cash" instead of the nine-month period.

For OPEB, accrual costs in 2019 are projected to be the second lowest[33] since inception of OEB's regulation of OPG's payment amounts, while the accrual-to-cash differential is projected to be the lowest (Ex. L-H-Staff-12). Although the OPEB differential is expected to increase modestly until the planned Pickering closure in 2024, the reduction in the company's workforce resulting from the closure will reduce the differential (as current service accruals will decrease while benefit payments will increase).

As Figure 1 below shows, discount rates have been low in recent years. Therefore, OPEB accrual costs (and the corresponding accrual-to-cash differential) will decline further if long-term bond yields underpinning the determination of these discount rates continue to increase. As OPG observed in EB-2013-0321, cash benefit payments would not be directly affected by changes in discount rates as the increasing trend in these payments is a function of the growing and aging retiree population and medical cost inflation.[34] In other words, as interest rates increase, ratepayers would not see a rate reduction on account of OPEB under a cash basis of recovery.

Figure 1: Other Post Retirement Benefits Discount Rate[35]



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[33] The lowest OPEB costs were in 2016, due to a one-time actuarial gain related to the long-term disability plan obligation.
[34] EB-2013-0321 Reply Argument, pp. 179-180.
[35] As used to determine OPG's actual other post retirement benefit costs for the years shown. 2019 is as reflected in Ex. H-L-Staff-12 for all years of the forecast period.

Numbers may not add due to rounding.

Historic, Current and Proposed Payment Amounts and Riders ($/MWh)

Line No.	Description	Note	2014	2015	2016	Jan - May 2017	Jun - Dec 2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Hydroelectric Payment Amount**	1					41.67	42.05	42.51	42.98	43.45
2	**Previously Regulated Hydroelectric Payment Amount**	2	40.20	40.20	40.20	40.20					
3	**Newly Regulated Hydroelectric Payment Amount**	3	41.93	41.93	41.93	41.93					
4	**EB-2012-0002 Hydroelectric Rider 2014-A**	4	2.02								
5	**EB-2013-0321 Previously Regulated Hydroelectric Rider 2015**	5		6.04							
6	**EB-2014-0370 Hydroelectric Rider 2015/16-A**	6		3.19	3.19						
7	**EB-2014-0370 Hydroelectric Rider 2015/16-B**	7		0.64	0.64						
8	**EB-2016-0152 Hydroelectric Payment Rider A**	8						0.52	1.44	1.01	
9	**EB-2016-0152 Hydroelectric Payment Rider B**	9						0.13	0.35	0.24	
10	**EB-2018-0243 Hydroelectric Payment Rider C**	10							1.65	1.65	1.56
11	**Nuclear Payment Amount**	11	59.29	59.29	59.29	59.29	77.96	78.64	77.00	85.00	89.70
12	**EB-2012-0002 Nuclear Rider 2014-A**	12	4.18								
13	**EB-2013-0321 Nuclear Rider 2015**	13		1.33							
14	**EB-2014-0370 Nuclear Rider 2015/16-A**	14		10.84	10.84						
15	**EB-2014-0370 Nuclear Rider 2015/16-B**	15		2.17	2.17						
16	**EB-2016-0152 Nuclear Payment Rider A**	16						1.05	2.79	2.04	
17	**EB-2016-0152 Nuclear Payment Rider B**	17						2.88	7.71	5.64	
18	**EB-2018-0243 Nuclear Payment Rider C**	18							4.55	4.76	3.43

Notes

1 Cols. (e) and (f) are the OEB-approved hydroelectric payment amounts per EB-2016-0152, PAO p. 9, para. 3.
Col. (g) is the 2019 hydroelectric payment amount requested for approval in this application.
Cols. (h) and (i) are illustrative hydroelectric payment amounts calculated using an annual adjustment to the hydroelectric rate of 1.1%.

2 Previously regulated hydroelectric payment amount effective November 1, 2014, per EB-2013-0321, PAO p. 6, para. 2.

3 Newly regulated hydroelectric payment amount effective November 1, 2014, per EB-2013-0321, PAO p. 7, para. 5.

4 Hydroelectric rider effective January 1, 2014 for recovery of approved DVA balances, per EB-2012-0002 PAO, p. 5, para. 5.

5 Previously regulated hydroelectric payment rider for the amortization of approved DVA balances effective January 1, 2015, per EB-2013-0321, PAO p. 7, para. 4.

6 Regulated hydroelectric payment amount rider for the recovery of approved DVA balances, effective July 1, 2015 to December 31, 2016, per EB-2014-0370 PAO, p. 3, para. 4.

7 Regulated hydroelectric Interim Period Shortfall Rider, effective October 1, 2015 to December 31, 2016, per EB-2014-0370 PAO, p. 3, para. 5.

8 Hydroelectric riders for the recovery of approved DVA balances for regulated hydroelectric facilities per EB-2016-0152 PAO p. 11, para. 8. Col. (f) is effective March 1, 2018. Cols. (g) and (h) are effective January 1 of each year.

9 Hydroelectric interim period shortfall recovery rider per EB-2016-0152 PAO p. 12, para. 10. Col. (f) is effective March 1, 2018. Cols. (g) and (h) are effective January 1 of each year.

10 Per Ex. H1-2-1 Table 1, cols. (g), (h) and (i), line 17.

11 Cols. (a) to (d) are nuclear payment amounts effective November 1, 2014, per EB-2013-0321, PAO p. 8, para. 7. Cols. (e) to (i) are nuclear payment amounts per EB-2016-0152 PAO p. 10, para. 4. Col. (e) is effective June 1, 2017. Cols. (f) to (i) are effective January 1 of each year.

12 Nuclear rider effective January 1, 2014 for recovery of approved DVA balances, per EB-2012-0002 PAO, p. 5, para. 8.

13 Nuclear payment rider for the amortization of approved DVA balances effective January 1, 2015, per EB-2013-0321, PAO p. 8, para. 8.

14 Nuclear payment amount rider for the recovery of approved DVA balances, effective July 1, 2015 to December 31, 2016, per EB-2014-0370 PAO, p. 3, para. 6.

15 Nuclear Interim Period Shortfall Rider, effective October 1, 2015 to December 31, 2016, per EB-2014-0370 PAO, p. 3, para. 7.

16 Nuclear riders for the recovery of approved DVA balances per EB-2016-0152 PAO p. 12, para. 9. Col. (f) is effective March 1, 2018. Cols. (g) and (h) are effective January 1 of each year.

17 Nuclear interim period shortfall recovery rider per EB-2016-0152 PAO p. 12, para. 11. Col. (f) is effective March 1, 2018. Cols. (g) and (h) are effective January 1 of each year.

18 Per Ex. H1-2-1 Table 2, cols. (g), (h) and (i), line 23.