H-Staff-1

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1

Please confirm which accounts will record interest.

Response

Pursuant to the EB-2016-0152 Payment Amounts Order (the "PAO"), OPG records interest on the balances in the following deferral and variance accounts using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts[1]:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Capacity Refurbishment Variance Account[2]
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Pension & OPEB Cash Payment Variance Account
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account[3]

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[1] EB-2016-0152 Payment Amounts Order, Appendix G, p. 17.
[2] OPG is not requesting disposition of the Capacity Refurbishment Variance Account in this proceeding.
[3] Interest was not recorded on the Bruce Lease Net Revenues Variance Account in 2016, pursuant to the EB-2014-0370 Payment Amounts Order.

- Nuclear Deferral and Variance Over/Under Recovery Variance Account
- Fitness for Duty Deferral Account[4]
- SR&ED ITC Variance Account

Pursuant to Appendix H of the EB-2016-0152 PAO, OPG records interest on the Rate Smoothing Deferral Account balance at the following OEB-approved long-term debt rates reflecting OPG's cost of long-term borrowing, compounded annually: 4.52% for 2019, 4.49% for 2020, and 4.48% for 2021.[5]

Pursuant to the EB-2016-0152 PAO and EB-2018-0002 Decision and Order, OPG does not record interest on the following deferral and variance accounts:

- Pension and OPEB Cost Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Nuclear Liability Deferral Account
- Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account
- Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account[6]

[4] OPG is not requesting disposition of the Fitness for Duty Deferral Account in this proceeding.
[5] EB-2016-0152 PAO, Appendix H, p. 2.
[6] OPG is not requesting disposition of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account in this proceeding.

H-Staff-2

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1/Page 6-7

Reference:
Ancillary Services Net Revenue Variance Account – Hydroelectric Sub-Account

(a) Please confirm what hydroelectric reference amounts have been used by OPG for calculation of account entries (a) for the period prior to the June 1, 2017, and (b) for the period commencing June 1, 2017.

(b) Please confirm for any other applicable hydroelectric accounts being requested for disposition, what reference amounts have been used by OPG for calculation of account entries (a) for the period prior to the June 1, 2017, and (b) for the period commencing June 1, 2017.

Response

(a) The total monthly reference amount for the Ancillary Services Net Revenue Variance Account – Hydroelectric for the periods prior to June 1, 2017 and the period commencing June 1, 2017 is $4.62M, as reflected in the following forecast amounts shown at Ex. H1-1-1, Table 3.

Chart 1*

	Ancillary Services Net Revenue Variance Account – Hydroelectric	**2016**	**Jan - May 2017**	**Jun - Dec 2017**
			(a)	(b)
1	Forecast Revenue ($M):			
2	Previously Regulated Hydroelectric	32.5	13.6	
3	Newly Regulated Hydroelectric	23.0	9.6	
4	Total Regulated Hydroelectric	55.5	23.1	32.4

*Numbers may not add up due to rounding.

The 2016 forecast revenue of $55.5M (Ex. H1-1-1 Table 3, line 3, col. (a)) is equal to $4.62M multiplied by 12 months. The January to May 2017 forecast revenue of $23.1M (Ex. H1-1-1 Table 3, line 3, col. (b)) is equal to $4.62M multiplied by five months. The June to December 2017 forecast revenue of $32.4M (Ex. H1-1-1 Table 3, line 3, col. (c)) is equal to $4.62M multiplied by seven months.

Per the EB-2014-0370 Payment Amounts Order, the monthly reference amount of $4.62M comprises $2.71M for previously regulated hydroelectric facilities and $1.91M for the newly regulated hydroelectric facilities.[1] Consistent with the presentation of Ancillary Service Net Revenues Variance Account entries in EB-2014-0370 and EB-2016-0152[2], the split between the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities' forecast amounts is correspondingly displayed in Ex. H1-1-1, Table 3, cols. (a) and (b) for the period prior to June 1, 2017. For the period commencing June 1, 2017, the forecast amount shown in Ex. H1-1-1 Table 3 is not split between the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities, consistent with the combined reference amount of $4.62M stipulated in the EB-2016-0152 Payment Amounts Order.[3]

[1] EB-2014-0370 Payment Amounts Order, Appendix B, p. 6.
[2] EB-2014-0370 Ex. H1-1-2, Table 3 and EB-2016-0152 Ex. H1-1-1, Table 3.
[3] EB-2016-0152 Payment Amounts Order, Appendix G, p. 5.

(b) There are two directly applicable hydroelectric accounts, described below: the Pension & OPEB Cash Payment Variance Account and the Hydroelectric Water Conditions Variance Account.

<u>Pension & OPEB Cash Payment Variance Account</u>

The total monthly reference amount for the Pension & OPEB Cash Payment Variance Account – Hydroelectric for the periods prior to June 1, 2017 and the period commencing June 1, 2017 is $3.76M for registered pension plan contributions and $1.07M for OPEB payments, as reflected in the following forecast amounts shown at Ex. H1-1-1, Table 7.

Chart 2*

	Pension & OPEB Cash Payment Variance Account	**2016**	**Jan - May 2017**	**Jun - Dec 2017**
	($M)		(a)	(b)
1	Forecast Pension Contributions	45.1	18.8	26.3
2	Forecast OPEB Payments	12.8	5.4	7.5
3	Total Forecast Pension and OPEB Cash Amounts	58.0	24.2	33.8

*Numbers may not add up due to rounding.

The 2016 forecast pension contributions of $45.1M (Ex. H1-1-1 Table 7, line 1, col. (a)) are equal to $3.76M multiplied by 12 months. The January to May 2017 forecast pension contributions of $18.8M (Ex. H1-1-1 Table 7, line 1, col. (d)) are equal to $3.76M multiplied by five months. The June to December 2017 forecast pension contributions of $26.3M (Ex. H1-1-1 Table 7, line 1, col. (g)) are equal to $3.76M multiplied by seven months.

Similarly, the 2016 forecast OPEB payments of $12.8M (Ex. H1-1- Table 7, line 2, col. (a)) are equal to $1.07M multiplied by 12 months. The January to May 2017 forecast OPEB payments of $5.4M (Ex. H1-1-1 Table 7, line 2, col. (d)) are equal to $1.07M multiplied by five months. The June to December 2017 forecast OPEB payments of $7.5M (Ex. H1-1-1 Table 7, line 2, col. (g)) are equal to $1.07M multiplied by seven months.

Per the EB-2014-0370 Payment Amounts Order, the monthly reference amount of $3.76M for pension contributions (comprises $1.32M for previously regulated hydroelectric facilities and $2.44M for the newly regulated hydroelectric facilities), and $1.07M for OPEB payments (comprises $0.38M for previously regulated hydroelectric facilities and $0.69M for newly regulated hydroelectric facilities).[4,5] For the period commencing June 1, 2017, combined reference amounts of $3.76M for pension contributions and $1.07M for OPEB payments were stipulated in the EB-2016-0152 Payment Amounts Order.[6]

<u>Hydroelectric Water Conditions Variance Account</u>

Per Ex. H1-1-1, Table 2, the Hydroelectric Water Conditions Variance Account forecast production for the periods prior to June 1, 2017 and the period commencing June 1, 2017 are as follows.

Chart 3*

	Hydroelectric Water Conditions Variance Account		**Jan - May 2017**	**Jun - Dec 2017**
			(a)	(b)
1	<u>Forecast Production (GWh)</u>:			
2	Previously Regulated Hydroelectric	20,556	8,619	11,937
3	Newly Regulated Hydroelectric	11,876	5,556	6,319
4	Total Regulated Hydroelectric	32,432	14,176	18,256

*Numbers may not add up due to rounding.

The above forecast production values for the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities are determined as set out in the EB-2016-0152 Payment Amounts Order, Appendix G, pp. 3-4 and EB-2014-0370 Payment Amounts Order, Appendix B, pp. 4-5. For all the above periods, these forecasts are determined in the same

[4] EB-2014-0370 Payment Amounts Order, Appendix B, pp. 15-16.
[5] A breakdown between previously regulated hydroelectric facilities and newly regulated hydroelectric facilities for the periods prior to June 1, 2017 is not displayed in Ex. H1-1-1 Table 7 to simplify presentation, consistent with EB-2016-0152: Ex. H1-1-1 Table 8 and Ex. L-9.1-1 Staff-209.
[6] EB-2016-0152 Payment Amounts Order, Appendix G, p. 12.

manner and using the same underlying monthly production forecasts underpinning the EB-2013-0321 payment amounts.

<u>Other Accounts</u>

As noted in Ex. H1-1-1 section 5.3, the Hydroelectric Incentive Mechanism Variance Account records a credit to ratepayers of 50 percent of hydroelectric incentive mechanism revenues above an annual threshold of $54.5M, both prior to June 1, 2017 and commencing June 1, 2017, as stipulated in the EB-2014-0370 Payment Amounts Order[7] and the EB-2016-0152 Payment Amounts Order,[8] respectively.

The following accounts are excluded from the response because, due to their nature, they either do not have a forecast-based reference amount (or implicitly have a reference amount of $0):

- Hydroelectric Surplus Baseload Generation Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Gross Revenue Charge Variance Account
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

For the Income and Other Taxes Variance Account, the monthly reference income tax expense for periods prior to June 1, 2017 is the regulated hydroelectric portion of the combined regulated hydroelectric and nuclear reference amount of $4.83M set out in the EB-2014-0370 Payment Amounts Order[9], at $5.62M[10]. For the period commencing June 1, 2017, the monthly reference income tax expense for the regulated hydroelectric facilities is set out in the EB-2016-0152 Payment Amounts Order, at $6.52M.[11] Account entries for 2016 and 2017

[7] EB-2014-0370 Payment Amounts Order, Appendix B, pp. 8-9.
[8] EB-2016-0152 Payment Amounts Order, Appendix G, p. 5.
[9] EB-2014-0370 Payment Amounts Order, Appendix B, p. 7.
[10] Calculated as 1/24 of the sum of: 2014 Income Taxes for the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities of $47.4M and $21.4M respectively and the 2015 Income Taxes for the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities of $40.1M and $25.8M respectively (EB-2013-0321 Payment Amounts Order, Appendix A: line 23 col. (c) of Table 1 and Table 2 respectively for 2014 and line 23 col. (f) of Table 1 and Table 2 respectively for 2015).
[11] EB-2016-0152 Payment Amounts Order, Appendix G, p.. 8.

presented in Ex. H1-1-1 Table 6 relate solely to Scientific Research & Experimental Development investment tax credits ("SR&ED ITCs"), a discrete element of the reference (and actual) income tax expense. As such, Table 6 shows these account entries in relation to the forecast SR&ED ITC amounts included in the above noted reference income tax expense values (and does not display the full reference income tax values themselves). This presentation does not impact the value of the entries in the account.

H-Staff-3

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1/Page 7

There were no additions into the Hydroelectric Incentive Mechanism (HIM) Account in 2016 and 2017 as actual HIM revenues were significantly below the specified threshold of $58M. Please explain what the drivers were behind the HIM revenues being significantly below the threshold.

Response

The HIM variance account threshold of $58M referenced above is the approved threshold amount for 2015. Additions to the account for 2016 and 2017 are relative to the approved threshold of $54.5M, as presented in Ex. H1-1-1, Table 4, line 2. The $54.5M value is the average of the 2014 annual threshold of $51M and 2015 annual threshold of $58M established in EB-2013-0321.[1]

HIM continues to follow the drivers which underpin operational decision-making related to the time shifting of energy, but the value of the actual drivers and actual conditions varied from those originally forecasted when the threshold basis was set in EB-2013-0321. The following conditions all affect the net HIM revenue actually realized:

- Weak market prices (HOEP) resulting in lower spread between on and off peak prices;
- Higher surplus baseload generation (SBG) levels, which in addition to contributing to weak market prices, can also increase the SBG Unintended Interaction adjustment that reduces net HIM revenue; and

[1] EB-2014-0370 Payment Amounts Order, App. B, p. 9; EB-2016-0152 Payment Amounts Order, App. G, p. 5.

- Stronger hydrological conditions (i.e., higher water inflows in 2016 and 2017 reduced the opportunities to time shift energy from low price to high price periods).

The result of the combination of these factors resulted in net HIM revenue actually realized being lower than threshold.

H-Staff-4

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1/Pages 7-8
Exhibit H1/Tab 1/Schedule 1/Table 5

As indicated in the above references, actual surplus baseload generation (SBG) foregone production due to SBG conditions in 2017 was higher than 2016. Foregone production 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.

Given that refurbishment of the first of Darlington nuclear's four reactors (i.e. unit 2) began in October 2016, please explain why foregone production values would be higher in 2017 than 2016.

Response

In general, SBG is a market condition whereby available baseload generation supply is greater than Ontario grid supplied demand plus net exports. The regulated hydroelectric foregone production due to SBG was higher in 2017 than 2016, due to the following market drivers:

- increased total hydroelectric production, due to increased inflows;
- increased nuclear production (primarily at Bruce Power), partially off-setting the Darlington Unit 2 refurbishment; and
- decreased Ontario grid supplied demand (demand reduction can contribute to higher SBG).

H-Staff-5

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1/Page 15

OEB staff notes a typographical error at line 26 of the above noted reference. EB-2016-0152 should be EB-2013-0321.

Please confirm that OPG agrees.

Response

OPG confirms there is a typographical error at Ex. H1-1-1, p. 15, line 26, that states "[t]he process for development of these assumptions is discussed in EB-2016-0321 Ex. F4-3-2, section 5.1 and EB-2016-0152 Ex. N1-1-1, section 3.1.2" (emphasis added). The reference to EB-2016-0321 should be EB-2016-0152.

H-Staff-6

Interrogatory

Reference:
Exhibit H1/Tab 2/Schedule 1/Pages 4-5

Reference:
Exhibit H1/Tab 2/Schedule 1/Tables 2 and 3

OPG is requesting recovery of the audited 2017 year-end balances (less amortization amounts approved in EB-2016-0152) in certain deferral and variance accounts. OPG proposes payment amount riders for the period January 1, 2019 to December 31, 2021.

Please explain OPG's rationale for a "straight-line" recovery as opposed to varying weightings similar to what was approved in EB-2016-0152.

Response

OPG proposes that approved account balances be recovered on a straight-line basis primarily based on the relative simplicity and minimal intergenerational inequity of this approach and its consistency with that authorized in OPG's previous stand-alone application to clear deferral and variance account balances (EB-2014-0370), as well as preceding cost-based rate applications (EB-2013-0321, EB-2010-0008 and EB-2007-0905). While OPG believes this approach is reasonable, it appreciates that the OEB has on occasion approved a weighted approach to recovery.[1]

[1] EB-2016-0152, OEB Decision on Draft Payment Amounts Order, dated March 12, 2018, p. 20

H-Staff-7

Interrogatory

Reference:

Exhibit A1/Tab 2/Schedule 2/Pages 1-3

Report of the OEB – Regulatory Treatment of Pension and OPEB Costs

The Report of the OEB on the Regulatory Treatment of Pension and OPEB costs states:

> For some utilities, the OEB has set rates using the cash method and used variance accounts to keep these prior periods open to further adjustments pending the outcome of this consultation. For these utilities, disposition of the variance account would be considered in the next cost-based rate application**, if the OEB approves the accrual method to recover pension and OPEB costs in rates.**[1]
>
> [1] EB-2015-0040, Report of the OEB on the Regulatory Treatment of Pension and Other Post Employment Benefit (OPEB) Costs, page 2, September 14, 2017

From the list of approvals being sought as part of this application, it is not clear if OPG is seeking an order to approve the use of the accrual method of recovery for its pension and OPEB costs effective November 1, 2014. Please clarify what is being requested as part of this application.

Response

In this application, OPG requests that the OEB approve recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account ("Interim Account") balance as of December 31, 2017 and the income tax impacts associated with the recovery of this audited balance, as set out in Ex. A1-2-2.

In EB-2013-0321, the OEB did not transition OPG away from the accrual basis of recovery, and the Interim Account audited balance is premised on the accrual method. OPG believes that the use of the accrual method is inherent in the OEB's approval to dispose of the balances in the Interim Account. As summarized below and further described in Ex. F1-1-1, this approach is consistent with the OEB's decisions in EB-2013-0321 and EB-2016-0152 and the policy set out in the EB-2015-0040 Report of the OEB on the Regulatory Treatment of Pension and OPEB costs ("Report"). The evidentiary basis for recovery of the Interim Account set out in Ex. L-H-Staff-8 supports continued use of the accrual method, which, as summarized in that response, results in just and reasonable rates.

As outlined in Ex. F1-1-1, the OEB set OPG's payment amounts based on the cash method as a temporary measure, pending the outcome of the generic consultation. In particular, in its Decision with Reasons in EB-2013-0321, the OEB established final payment amounts effective November 1, 2014 by setting the amount of the company's pension and OPEB costs included in the revenue requirement equal to its cash requirements for the period.[1] In doing so, the OEB did not make a determination that altered the status quo – it neither determined that the accrual accounting method of recovery was inappropriate for OPG's pension and OPEB costs nor did it make a finding discontinuing the accrual method or transitioning OPG to the cash method. Rather, the OEB effectively deferred a final determination of whether OPG should recover those costs on an accrual basis pending the outcome of the generic consultation.[2] This approach was continued by the OEB in the EB-2016-0152 Decision and Order. The final Report (issued subsequent to the close of record in the EB-2016-0152 proceeding) established the OEB's policy that accrual accounting is presumptively appropriate for recovery of pension and OPEB costs, and that utilities using the accrual method are not required to justify the use of that method.[3]

[1] EB-2013-0321, Decision with Reasons, dated November 20, 2014, pp. 88-89.
[2] As described in Ex. F1-1-1, OPG's request to recover the Interim Account balance is based on the specific payment orders that govern the account (as issued by the OEB in EB-2013-0321 and EB-2016-0152) and the application of OEB policy on pension and OPEB costs as set out in the Report. In effect, the prior payment amount decisions limit future decisions on the Interim Account to (i) the OEB's findings in the generic consultation on the appropriate regulatory accounting approach for pension and OPEB costs, and (ii) the mechanics of recovery.
[3] EB-2015-0040, Report of the OEB, Regulatory Treatment of Pension and Other Post-employment (OPEBs) Costs, p. 8.

Based on the above, OPG does not believe that it is necessary for it to seek an order re-opening the EB-2013-0321 or EB-2016-0152 payment amounts or otherwise approving the continued use of the accrual method of recovery for pension and OPEB costs. Rather, OPG is seeking an OEB order authorizing the recovery of the Interim Account balance on the basis of the policy determinations in the Report that address the reasons for the deferral of these costs in the first place.

In the EB-2016-0152 Decision and Order, the OEB determined that OPG may seek to recover the audited balance of the Interim Account (and make a proposal for the regulatory accounting method for pension and OPEB costs going forward) in this deferral and variance account clearance application, supported by appropriate evidence.[4] In addition to outlining OPG's proposal and rationale for the requested recovery of the audited Interim Account balance, Ex. F1-1-1 set outs OPG's expectation that its next cost-based payment amounts application would reflect continued recovery of pension and OPEB costs calculated pursuant to the accrual accounting method consistent with the Report's findings and this application. Given the nature of the current application to clear historical deferral and variance account balances, OPG has not sought an order from the OEB related to recovery of pension and OPEB costs of future periods.

[4] EB-2016-0152, Decision and Order, December 28, 2017, p. 119 and p. 160.

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 $560M between 2018 and 2024, compared to approximately $360M by which accrual costs cumulatively exceeded cash funding contributions between 2008 and 2017.

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[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	134.7	106.2	83.2	65.0	48.3	48.6	3,499.8
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	3,695.6
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	(49.6)	(82.1)	(97.4)	(119.3)	(139.6)	(139.5)	(195.8)

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 $50M (which approximately 10% 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 2020. By 2024, the combined pension and OPEB accrual costs are projected to be approximately $55M lower than the combined cash amounts (Nuclear and Regulated Hydroelectric).

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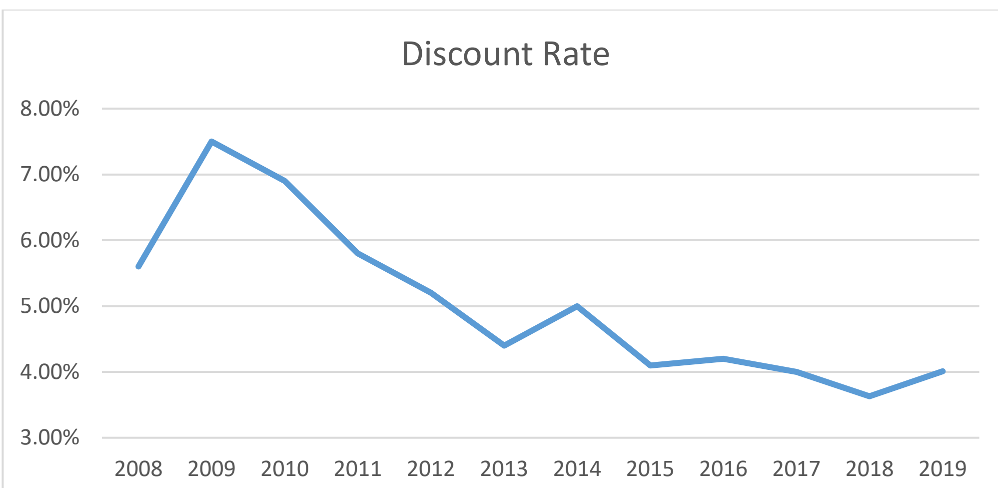
[32] Subject to below, 2008-2013 per EB-2013-0321 Argument-in-Chief, p. 105, Chart 4. 2015-2017 per Ex. H-1-1, Tables 7 and 7a, lines 4 and 8 (sum of Nuclear and Regulated Hydroelectric). 2018-2024 per Ex. L-H-Staff-12, Charts 5 and 6 (sum of Nuclear and Regulated Hydroelectric). 2008 represents the 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.

H-Staff-9

Interrogatory

Reference:
Exhibit H1/Tab 1/Schedule 1/Table 7

At the above reference, OPG has provided a table that shows the 2016 and 2017 additions made to the Pension and OPEB Cash versus Accrual Differential Deferral Account.

(a) Please explain why the total actual pension and OPEB accrual amounts (combined nuclear and hydroelectric) as presented in line 10 of Table 7 do not agree to the corresponding amounts per the actuarial valuation provided.[1]
(b) Please also confirm that the explanation provided for the above also explains why the total actual cash payments made in respect to pension and OPEBs for the purposes of calculating the additions to the Pension and OPEB Cash Payments Variance Account (as presented in table 7) do not agree to the actual amounts presented in the actual valuations.

[1] Exhibit H1, Tab1, Schedule 1, Attachment 3, page 5

Response

(a) The corresponding amounts in the actuarial valuation report provided in Ex. H1-1-1, Attachment 3, are total OPG pension and OPEB costs, as calculated pursuant to the accrual accounting method. As indicated in Ex. H1-1-1, p. 15, lines 14-16, in calculating the amounts presented in line 10 of Table 7 for the prescribed facilities, OPG's total accrual pension and OPEB costs were attributed to these prescribed facilities using the same methodology as in the previous proceedings.[1]

[1] For example, see EB-2016-0152, Ex. F4-3-2, Section 5.2.

(b) Confirmed. As indicated in Ex. H1-1-1, p. 14, lines 8-10, in calculating the actual pension and OPEB cash amounts presented in line 6 of Table 7 for the prescribed facilities, OPG's total contributions to the registered pension plan and OPEB benefit payments were attributed to these prescribed facilities using the same methodology as in the previous proceedings.

H-Staff-10

Interrogatory

Reference:
Exhibit F1/Tab1/Schedule 1/page 9

At the above reference, OPG is proposing that recoveries of amounts recorded in the Interim Account as of December 31, 2017 would not be captured in the New Differential Account and therefore not be subject to carrying charges.

Please quantify what the expected carrying charges would be on the balance in the Interim account as at December 31, 2017 if the balance is transferred to the new Differential Account. Please also provide details supporting the calculation and any assumptions that were used.

Response

The requested information is provided in Attachment 1 to this response, which is a modified version of Ex. F1-1-1, Chart 1 (p. 12, line 8).

Exhibit F1-1-1 Chart 1 compares two illustrative utilities that are identical except for the funding of pension and OPEB costs in rates:

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

Attachment 1 to this response adopts a similar format as Ex. F1-1-1 Chart 1 to demonstrate the implications on OPG from a different treatment of the funding of pension and OEPB costs in rates. Attachment 1 shows, for a ten-year period beginning in 2019, the additional interest costs incurred by OPG, whose rates for a pre-2018 period were temporarily set on the basis of pension and OPEB cash amounts in prior years (line 2), compared to an identical utility whose rates were set using the accrual basis (line 1) for that period. These calculations are based on OPG's December 31, 2017 Pension & OPEB Cash Versus Accrual Differential Deferral Account (Interim Account) balance of $613.7M (first note in Chart 1), and proposed straight-line recovery over the eight year period from January 1, 2019 to December 31, 2026.

The below describes the additional interest costs to OPG shown in Attachment 1, in a similar format used to describe the impacts between illustrative Utility A and Utility B at Ex. F1-1-1, pp. 12 and 13. These costs are calculated using the current (Q4 2018) OEB-prescribed interest rate for construction work in progress of 3.35% (Ex. F1-1-1, footnote 5). Additional assumptions are found in Attachment 1.

Inconsistent Cash Flow: As shown at line 4, the use of the accrual basis to recover pension and OPEB costs in rates results in a higher cash flow in the earlier years than that of the comparator utility (line 2), by the unrecovered portion of the December 31, 2017 Interim Account balance[1], and therefore, OPG would incur a total of $82.2M in additional interest costs (line 5), over the eight-year recovery period January 1, 2019 to December 31, 2026. Although this difference in cash flow is a source of relative inequality attributable solely to the basis of pension and OPEB cost recovery, OPG is not proposing that the OEB address this issue.

Inconsistent Carrying Charges: Since OPG's rates were temporarily set on the basis of cash amounts, it recorded amounts at line 4 in its Interim Account. The December 31, 2017 balance of $613.7M in the account is proposed to be recovered through a rate rider over an eight-year period commencing January 1, 2019, determined on a straight-line basis (line 2). Recovered amounts would be tracked annually in the New Differential Account (line 6), and carrying charges (line 8) would be applied on the cumulative balance (line 7). Carrying charges would continue until such time as OPG's cumulative cash pension and OPEB payments from January 1, 2018 exceed its cumulative accrual costs by $613.7M. Attachment 1 shows that these charges would total $123.3M for the illustrative ten-year period to 2028, assuming no further

[1] For simplicity, the incremental interest costs already incurred by OPG in the period 2014-2018 while it was collecting less than a comparator utility whose rates continued to reflect accrual costs are not shown.

additions to the New Differential Account beyond recoveries of the December 31, 2017 Interim Account balance (line 8). If OPG's rates had reflected accrual amounts prior to January 1, 2018 (and therefore had no recoverable balance to track in the New Differential Account), OPG would not be subject to these carrying charges.

Chart 1: OPG Interest Cost Impact of Different Rate Treatments for Pre-2018 Pension and OPEB Cost Recovery

Line	Particulars ($M)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
	Timing of Recovery Interest Costs:[#]												
1	Pre-2018 Rates on Accrual Amounts*	613.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	613.7
2	Pre-2018 Rates on Cash Amounts; Cash to Accrual Diff. in Riders[##]		76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.8	0.0	0.0	613.7
3	Annual Cash Flow Difference (line 1 - line 2)*	613.7	(76.7)	(76.7)	(76.7)	(76.7)	(76.7)	(76.7)	(76.7)	(76.8)	0.0	0.0	0.0
4	Cumulative Cash Flow Difference / Interim Account Balance*	613.7	537.0	460.3	383.6	306.9	230.2	153.5	76.8	0.0	0.0	0.0	n/a
5	Annual simple interest impact on cumulative cash flow differences due to timing of recovery**		19.3	16.7	14.1	11.6	9.0	6.4	3.9	1.3	0.0	0.0	**82.2**
	New Differential Account:												
6	Annual Amount Recorded (equal to line 2)		76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.8	0.0	0.0	613.7
7	Cumulative Account Balance***		76.7	153.4	230.1	306.8	383.5	460.2	536.9	613.7	613.7	613.7	n/a
8	Annual simple interest impact on cumulative account balance due to carrying charges****		1.3	3.9	6.4	9.0	11.6	14.1	16.7	19.3	20.6	20.6	**123.3**
9	**Total Incremental Cost Impact** (line 5 + line 8)		20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	**205.6**

Notes:

* 2018 value is December 31, 2017 Interim Account balance, comprised of $83.2M for regulated hydroelectric (Ex H1-2-1 Table 1, line 10, col (c)) and $530.5M for nuclear (Ex H1-2-1 Table 2, line 13, col (c)). Subsequent years at line 4 are prior year's Cumulative Cash Flow (line 4) plus current year's Annual Cash Flow Difference (line 3).

** [Prior year's Cumulative Cash Flow Difference (line 4) plus current year's Cumulative Cash Flow Difference (line 4)] / 2 * 3.35% Q4 2018 CWIP interest rate prescribed by the OEB.

*** Prior year's Cumulative Account Balance (line 7) plus current year's Annual Amount Recorded (line 6).

**** [Prior year's Cumulative Account Balance (line 7) plus current year's Cumulative Account Balance (line 7)] / 2 * 3.35% Q4 2018 CWIP interest rate prescribed by the OEB.

[#] To focus the analysis on the treatment of cash to accrual differences arising prior to the January 1, 2018 effective date of the New Differential Account, OPG assumed accrual costs equal to cash amounts starting in 2018 and continuing until 2028.

[##] Proposed recovery on a straight-line basis over an 8 year period from 2019 to 2026, with annual recovery amount of $76.7M comprised of $10.4M for regulated hydroelectric (Ex. H1-2-1 Table 1, line 10, cols (g, h, i)) and $66.3M for nuclear (Ex H1-2-1 Table 2, line 13, cols (g, h, i)).

H-Staff-11

Interrogatory

Reference:
Exhibit F1/Tab 1/Schedule 1/page 9

At the above reference, OPG has proposed that the recoveries of amounts recorded in the Interim Account as of December 31, 2017 should not be captured in the New Differential Account and therefore not be subject to carrying charges.

OPG continues to record amounts in the Interim Account beyond December 31, 2017 and is required to do so up until its next rebasing application. Please explain whether OPG believes that amounts recorded in the Interim Account beyond December 31, 2017 should also not be captured by the New Differential Account and therefore not be subject to carrying charges.

Response

OPG understands the intent of the question to be whether OPG believes that recoveries of amounts recorded in the Interim Account beyond December 31, 2017 should also not be captured by the New Differential Account and therefore not be subject to carrying charges.[1]

Although the treatment of amounts recorded in the Interim Account beyond December 31, 2017 is beyond the scope of this application, OPG believes it would be a consistent and fair application of policy to capture such amounts in the New Differential Account if and when those amounts are recovered.

[1] This intent would be consistent with the policy set out EB-2015-0040 Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017, which states with respect to previously approved accrual versus cash variance accounts at p. 22 in Appendix C: "[a]s these utilities are collecting amounts from monthly rate riders relating to the previously approved account(s), they will also be required to record a corresponding monthly entry to the new Pension & OPEB Forecast Accrual Versus Cash Payment Differential variance account." (emphasis added)

H-Staff-12

Interrogatory

Reference:

Exhibit F1/Tab 1/Schedule 1

Using OPG's most recent actuarial valuation and other relevant data, please prepare a table that compares the expected pension and OPEB costs on a cash basis versus on an accrual accounting basis over the next 10-years (i.e. from 2018 inclusive). Please present the information separately for both the Nuclear and Hydroelectric operations.

If OPG is unable to produce a forecast over the requested period, please explain why it is not possible and then prepare a forecast over a period of time that the current available information permits.

Response

Provided below is a current seven-year forecast of pension and OPEB accrual costs and cash amounts[1] for 2018 to 2024. OPG does not have a current 10-year forecast because of inherent planning uncertainties, at the present time, related to the impact of executing a downsizing program in connection with the planned closure of the Pickering generating station by the end of 2024 on the last three years of the 10-year period. An ongoing review of planning assumptions related to the nature, timing and scope of the downsizing program, including its interaction with the work to de-fuel, de-water and place the Pickering units in a safe storage state following the end of commercial operations, can cause material variability in OPG's workforce and therefore pension and OPEB costs over the three-year period in question.

The total OPG forecast of pension and OPEB accrual costs and cash amounts for the seven-year period was prepared by OPG's independent actuary, Aon Hewitt. The forecast reflects

[1] Cash amounts consist of contributions to the registered pension plan ("pension"), and benefit payments to retirees and dependants under all other post-employment benefit plans ("OPEB").

the most recent actuarial valuation of the registered pension plan, which is as of January 1, 2018[2], an estimate of the associated comprehensive accounting valuation to determine OPG's year-end 2018 plan obligations, and other inputs consistent with current planning assumptions. It was developed in the same manner as in OPG's prior proceedings, including EB-2016-0152.[3] Charts 1 through 4 below provide the nuclear and regulated hydroelectric portions of the total OPG forecast accrual costs and cash amounts, with Charts 5 and 6 showing the corresponding accrual to cash differentials.[4] Total OPG pension and OPEB accrual costs and cash amounts were attributed to these facilities using the same methodology as in prior proceedings.

Chart 1

Pension and OPEB Cash Amounts – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	155.4	158.4	161.5	154.4	157.5	160.7	160.9
OPEB	89.5	92.6	95.8	97.6	98.7	101.9	104.6
Total	**244.9**	**251.0**	**257.2**	**252.0**	**256.3**	**262.6**	**265.5**

[2] The most recent actuarial valuation was filed with the Financial Services Commission of Ontario in September 2018 and sets the minimum funding requirements for 2018 to 2020.
[3] See EB-2016-0152 Ex. F4-3-2, sections 4.1 and 5.1.
In summary, to forecast pension plan contributions, Aon Hewitt projected the results of the next funding valuation of OPG's pension fund as of the latest permitted date January 1, 2021 and, subsequently as of January 1, 2024, applying the January 1, 2018 valuation assumptions as updated for changes in prescribed assumptions. Forecast accrual costs for pension and OPEB were determined in accordance with US GAAP using the actual year-end 2017 benefit obligation values and the actual pension fund asset value, applying actuarial assumptions provided or agreed to by an independent actuary. This includes an estimate of the impact of a new comprehensive accounting valuation to determine OPG's year-end 2018 benefit obligations, triggered by the availability of more current information as a result of performing the January 1, 2018 funding valuation and the requirement to ensure that the obligations continue to be fairly stated. Cash amounts for OPEB represent forecast benefit payments to retirees and dependants in accordance with the provisions of the plans, and are based on estimated future cash flows used to project the corresponding benefit obligations.
[4] Numbers may not calculate due to rounding.

Chart 2

Pension and OPEB Cash Amounts – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	25.2	26.0	26.8	26.2	26.7	27.2	27.3
OPEB	14.5	15.2	15.9	16.5	16.7	17.3	17.7
Total	**39.6**	**41.2**	**42.7**	**42.7**	**43.5**	**44.5**	**45.0**

Chart 3

Pension and OPEB Accrual Costs – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	217.4	90.7	67.1	47.6	32.3	18.3	17.6
OPEB	170.2	157.4	160.9	163.7	167.1	171.9	177.4
Total	**387.6**	**248.1**	**228.0**	**211.3**	**199.4**	**190.2**	**195.0**

Chart 4

Pension and OPEB Accrual Costs – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	35.2	14.9	11.1	8.1	5.5	3.1	3.0
OPEB	27.5	25.8	26.7	27.7	28.3	29.1	30.1
Total	**62.7**	**40.7**	**37.8**	**35.8**	**33.8**	**32.3**	**33.1**

Chart 5

Pension and OPEB Accrual-Cash Differential – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	62.0	(67.6)	(94.4)	(106.8)	(125.2)	(142.4)	(143.3)
OPEB	80.6	64.8	65.1	66.1	68.4	70.0	72.8
Total	**142.7**	**(2.8)**	**(29.3)**	**(40.7)**	**(56.9)**	**(72.4)**	**(70.5)**

Chart 6

Pension and OPEB Accrual-Cash Differential – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	10.0	(11.1)	(15.7)	(18.1)	(21.2)	(24.1)	(24.3)
OPEB	13.0	10.6	10.8	11.2	11.6	11.9	12.3
Total	**23.1**	**(0.5)**	**(4.9)**	**(6.9)**	**(9.6)**	**(12.3)**	**(11.9)**

The total accrual-to-cash differential is projected to decline through the forecast period, with cash amounts exceeding accrual costs starting in 2019. This reflects a decrease in accrual costs, primarily due to the following:

- an increase in discount rates used to determine the projection, compared to those as of year-end 2017 used to set the 2018 costs, reflecting an increase in long-term bond yields observed in 2018 to date;
- earnings on the pension asset (at the expected rate of return) that are increasing faster than the interest cost on the benefit obligation (at the discount rate); and
- lower amortizations of net actuarial losses under the corridor approach.

A further discussion of the forecast is included in Ex. L-H-Staff-8.

H-Staff-12

Interrogatory

Reference:

Exhibit F1/Tab 1/Schedule 1

Using OPG's most recent actuarial valuation and other relevant data, please prepare a table that compares the expected pension and OPEB costs on a cash basis versus on an accrual accounting basis over the next 10-years (i.e. from 2018 inclusive). Please present the information separately for both the Nuclear and Hydroelectric operations.

If OPG is unable to produce a forecast over the requested period, please explain why it is not possible and then prepare a forecast over a period of time that the current available information permits.

Response

Provided below is a current seven-year forecast of pension and OPEB accrual costs and cash amounts[1] for 2018 to 2024. OPG does not have a current 10-year forecast because of inherent planning uncertainties, at the present time, related to the impact of executing a downsizing program in connection with the planned closure of the Pickering generating station by the end of 2024 on the last three years of the 10-year period. An ongoing review of planning assumptions related to the nature, timing and scope of the downsizing program, including its interaction with the work to de-fuel, de-water and place the Pickering units in a safe storage state following the end of commercial operations, can cause material variability in OPG's workforce and therefore pension and OPEB costs over the three-year period in question.

The total OPG forecast of pension and OPEB accrual costs and cash amounts for the seven-year period was prepared by OPG's independent actuary, Aon Hewitt. The forecast reflects

[1] Cash amounts consist of contributions to the registered pension plan ("pension"), and benefit payments to retirees and dependants under all other post-employment benefit plans ("OPEB").

the most recent actuarial valuation of the registered pension plan, which is as of January 1, 2018[2], an estimate of the associated comprehensive accounting valuation to determine OPG's year-end 2018 plan obligations, and other inputs consistent with current planning assumptions. It was developed in the same manner as in OPG's prior proceedings, including EB-2016-0152.[3]

Charts 1 through 4 below provide the nuclear and regulated hydroelectric portions of the total OPG forecast accrual costs and cash amounts, with Charts 5 and 6 showing the corresponding accrual to cash differentials.[4] Total OPG pension and OPEB accrual costs and cash amounts were attributed to these facilities using the same methodology as in prior proceedings.

Chart 1

Pension and OPEB Cash Amounts – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	155.4	158.4	161.5	154.4	157.5	160.7	160.9
OPEB	89.5	92.6	95.8	97.6	98.7	101.9	104.6
Total	**244.9**	**251.0**	**257.2**	**252.0**	**256.3**	**262.6**	**265.5**

[2] The most recent actuarial valuation was filed with the Financial Services Commission of Ontario in September 2018 and sets the minimum funding requirements for 2018 to 2020.
[3] See EB-2016-0152 Ex. F4-3-2, sections 4.1 and 5.1.
In summary, to forecast pension plan contributions, Aon Hewitt projected the results of the next funding valuation of OPG's pension fund as of the latest permitted date January 1, 2021 and, subsequently as of January 1, 2024, applying the January 1, 2018 valuation assumptions as updated for changes in prescribed assumptions. Forecast accrual costs for pension and OPEB were determined in accordance with US GAAP using the actual year-end 2017 benefit obligation values and the actual pension fund asset value, applying actuarial assumptions provided or agreed to by an independent actuary. This includes an estimate of the impact of a new comprehensive accounting valuation to determine OPG's year-end 2018 benefit obligations, triggered by the availability of more current information as a result of performing the January 1, 2018 funding valuation and the requirement to ensure that the obligations continue to be fairly stated. Cash amounts for OPEB represent forecast benefit payments to retirees and dependants in accordance with the provisions of the plans, and are based on estimated future cash flows used to project the corresponding benefit obligations.
[4] Numbers may not calculate due to rounding.

Chart 2

Pension and OPEB Cash Amounts – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	25.2	26.0	26.8	26.2	26.7	27.2	27.3
OPEB	14.5	15.2	15.9	16.5	16.7	17.3	17.7
Total	**39.6**	**41.2**	**42.7**	**42.7**	**43.5**	**44.5**	**45.0**

Chart 3

Pension and OPEB Accrual Costs – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	217.4	115.7	91.1	71.2	55.5	41.3	41.6
OPEB	170.2	157.4	160.9	163.7	167.1	171.9	177.4
Total	**387.6**	**273.1**	**251.9**	**234.8**	**222.6**	**213.2**	**219.0**

Chart 4

Pension and OPEB Accrual Costs – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	35.2	19.0	15.1	12.1	9.4	7.0	7.1
OPEB	27.5	25.8	26.7	27.7	28.3	29.1	30.1
Total	**62.7**	**44.8**	**41.8**	**39.8**	**37.8**	**36.2**	**37.1**

Chart 5

Pension and OPEB Accrual-Cash Differential – Nuclear ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	62.0	(42.6)	(70.4)	(83.3)	(102.0)	(119.4)	(119.3)
OPEB	80.6	64.8	65.1	66.1	68.4	70.0	72.8
Total	**142.7**	**22.2**	**(5.3)**	**(17.2)**	**(33.6)**	**(49.3)**	**(46.5)**

Chart 6

Pension and OPEB Accrual-Cash Differential – Regulated Hydroelectric ($M)							
	2018 Projection	**2019 Projection**	**2020 Projection**	**2021 Projection**	**2022 Projection**	**2023 Projection**	**2024 Projection**
Pension	10.0	(7.0)	(11.7)	(14.1)	(17.3)	(20.2)	(20.2)
OPEB	13.0	10.6	10.8	11.2	11.6	11.9	12.3
Total	**23.1**	**3.6**	**(0.9)**	**(2.9)**	**(5.7)**	**(8.4)**	**(7.9)**

The total accrual-to-cash differential is projected to decline through the forecast period, with cash amounts exceeding accrual costs starting in 2020. This reflects a decrease in accrual costs, primarily due to the following:

- an increase in discount rates used to determine the projection, compared to those as of year-end 2017 used to set the 2018 costs, reflecting an increase in long-term bond yields observed in 2018 to date;
- earnings on the pension asset (at the expected rate of return) that are increasing faster than the interest cost on the benefit obligation (at the discount rate); and
- lower amortizations of net actuarial losses under the corridor approach.

A further discussion of the forecast is included in Ex. L-H-Staff-8.

H-Staff-13

Interrogatory

Reference:
Exhibit F1/Tab 1/Schedule 1

Reference:
Report of the OEB – Regulatory Treatment of Pension and OPEB Costs

With respect to the use of the accrual method as the default to recover pension and OPEB costs, The Report of the OEB on the Regulatory Treatment of Pension and OPEB costs states:

> In summary, this Report establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications. A panel of the OEB can use another method if accrual accounting does not result in just and reasonable rates.[1]
>
> [1] EB-2015-0040, Report of the OEB on the Regulatory Treatment of Pension and Other Post Employment Benefit (OPEB) Costs, page 2, September 14, 2017

Using the forecast of the pension and OPEB costs that was provided in Ex.L-H-Staff-12, please explain why OPG believes that the use of the accrual method will result in just and reasonable rates. In providing this response, please address pensions and OPEBs separately.

Response

OPG sets out its submissions in support of the accrual method of accounting for pension and OPEB costs in Ex. L-H-Staff-8, which in turn considers the forecast of pension and OPEB costs and cash amounts provided in Ex. L-H-Staff-12. OPG believes its response in L-H-Staff-8 provides the basis for which the use of the accrual method results in just and reasonable rates.

H-AMPCO-1

Interrogatory

Reference:
Ex H1 T1 S1 P6

Preamble: The evidence indicates the hydroelectric ancillary revenues were higher in 2016 and 2017 than the reference amounts primarily due to higher regulation service revenue and operating reserve revenue, partially offset by lower reactive support revenue.

a) Please provide the reference amounts compared to the 2016 and 2017 amounts for each of the above components.

b) Please explain the key drivers for the variances in the above components.

Response

a) Hydroelectric ancillary services forecast and actual revenues for 2016 and 2017 are provided in Chart 1 and Chart 2, respectively.[1]

Chart 1*

Forecast Revenue ($M)	2016	Jan – May 2017	Jun – Dec 2017	Total 2017
Black Start	0.5	0.2	0.3	0.5
Reactive Power	15.5	6.5	9.0	15.5
Regulation Service [2]	28.0	11.7	16.3	28.0
Operating Reserve	11.5	4.8	6.7	11.5
Total	**55.5**	**23.1**	**32.4**	**55.5**

*Numbers may not add due to rounding.

[1] The OEB approved the total reference amount in EB-2014-0370 (as between the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities) and EB-2016-0152. The reference amounts were not approved on a component basis.
[2] Previously referred to as automatic generation control (AGC).

Total forecast revenue in Chart 1 above is per Ex. H1-1-1 Table 3, line 3.

Chart 2*

Actual Revenue ($M)	**2016**	**Jan – May 2017**	**Jun – Dec 2017**	**Total 2017**
Black Start	0.4	0.1	0.2	0.3
Reactive Power	8.5	1.9	8.4	10.3
Regulation Service	38.7	18.6	24.7	43.3
Operating Reserve	22.5	10.4	14.3	24.7
Total	**70.1**	**31.0**	**47.6**	**78.7**

*Numbers may not add due to rounding.

Total actual revenue in Chart 2 above is per Ex. H1-1-1 Table 3, line 6.

b) The key drivers for the variances between the amounts in Chart 1 and Chart 2 are attributable to:

- a new regulation service contract that updated opportunity cost components to reflect the change from Hourly Ontario Energy Price to OEB-approved regulated hydroelectric rates in all applicable payment equations;
- higher than forecast prices for operating reserve (both 10-minute spinning reserve and 10-minute non-spinning reserve), which impacted both operating reserve and regulation service revenues; and
- a new reactive power contract that contains updated cost recovery parameters and lower actual requirement for reactive power while in condense mode.

H-AMPCO-2

Interrogatory

Reference:
Ex H1 T1 S1 P11

Preamble: OPG proposes to defer the clearance of the nuclear amounts in the CRVA nuclear account to a future application.

a) Please confirm this account also includes non-DRP entries.

b) Please provide the balance in the nuclear CRVA account excluding DRP-related variances.

Response

a) OPG confirms the amounts in the Capacity Refurbishment Variance Account - Nuclear ("nuclear CRVA") includes non-DRP entries.

b) OPG declines to provide the requested information on the basis of relevance, as OPG is not seeking clearance of the balance in the nuclear CRVA in this application[1].

[1] Ex. H-1-1-1, p.11.

H-AMPCO-3

Interrogatory

Reference:
Ex H1 T1 S1 P13 Gross Revenue Charge VA

Preamble: The Gross Revenue Charge Variance Account records the cost impact of a gross revenue reduction pertaining to production increases at OPG's Sir Adam Beck plants due to the operation of the new Niagara tunnel.

Please provide the production increases at OPG's Sir Adam Beck plants due to the operation of the new Niagara tunnel.

Response

Please see Ex. L-H-CME-1. OPG declines to provide the requested information on the basis of relevance. This interrogatory requests production information related to the future recording of amounts in the Gross Revenue Charge Variance Account, which is not relevant to the determination of issues or approvals being sought as part of this application.

H-AMPCO-4

Interrogatory

Reference:

EB-2016-0152 C2-1-2 P3

Preamble: The nuclear liabilities update indicates, "As at December 31, 2016, the Decommissioning Segregated Fund ("DF") was overfunded at approximately 121% and the Used Fuel Segregated Fund ("UFF") was marginally overfunded at less than 1%, relative to the corresponding funding obligations per the 2017 ONFA Reference Plan. As reflected in Ex. N1-1-1, OPG expected this to result in overall zero required contributions to each of the funds until the next ONFA reference plan is approved.

Please provide an update on the funds as per the above as of December 31, 2017.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on the funded status of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund as at December 31, 2017, which is not relevant to the determination of issues or approvals being sought as part of this application.

H-AMPCO-5

Interrogatory

Reference:
EB-2016-0152 J20.7

Please update Chart 1 to include 2017 data. Please separately identify ONFA expenses and internally funded expenses.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on after-tax amounts collected and expended for nuclear liabilities, which is not relevant to the determination of issues or approvals being sought as part of this application.

H-CCC-1

Interrogatory

Reference:
Ex. H1/T1/S1/p. 4

Please list all of the accounts that do not attract interest and provide the rationale for excluding it.

Response

A list of accounts that do not attract interest is provided in the response to Ex. L-H-Staff-1. As described in that response, OEB direction determines whether or not interest is applied to deferral and variance accounts.

H-CCC-2

Interrogatory

Reference:
Ex. H1/T1/S1/p. 8

Re: Hydroelectric Surplus Baseload Generation VA - Please explain how OPG determines "Actual Foregone Production Due to SBG Conditions".

Response

The methodology for determining actual foregone production due to surplus baseload generation ("SBG") conditions is described at EB-2016-0152 Payment Amounts Order, Appendix G, pages 6-7 as follows:

> As described in EB-2013-0321, Ex. E1-2-1, section 3.2, OPG shall continue to calculate foregone production due to SBG conditions by starting with the total volume of spill at the regulated hydroelectric stations and subtracting the volume of spill due to factors such as:
>
> - water conveyance constraints (e.g., Sir Adam Beck Generating Station tunnel capacity constraints);
> - production capability constraints (e.g., unit outages, operating regulatory requirements);
> - market constraints (i.e., IESO dispatch constraints); and
> - contractual obligations (e.g., regulation service).
>
> The remaining spill volume is identified as potential SBG spill. From this volume, OPG excludes spill that occurs when the Ontario market price is above the level of the GRC. The volume of spill remaining after this adjustment is the foregone production due to SBG conditions that is used to record entries in this account.

H-CCC-3

Interrogatory

Reference:
Ex. H/T1/S1/p. 23

Please explain the reason for the $29M debit in the Nuclear Deferral and Variance Over/Under Recovery Account.

Response

The calculation of the $29M debit in the Nuclear Deferral and Variance Over/Under Recovery Variance Account is set out at Ex. H1-1-1, Table 13.

Per the account description at Ex. H1-1-1, Page 23, the Nuclear Deferral and Variance Over/Under Recovery Variance 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."

There were two nuclear riders effective in 2016, as shown at lines 1 and 2 of Ex. H1-1-1, Table 13. These riders were designed based on a production forecast, as shown at lines 3 and 6. Actual production was less than forecast, as shown at lines 4 and 7. The variance in production, as shown at lines 5 and 8, multiplied by the riders at lines 1 and 2, result in a $29M debit to the variance account.

H-CCC-4

Interrogatory

Reference:
Ex. H1/T1/S1/Table 1c

Of the total $1.4105 billion 2017 Audited Year End Balance – how much of that amount is OPG seeking to recover through this Application?

Response

Of the total $1.4105 billion 2017 Audited Year End Balance, OPG is seeking to recover $1.117 billion through this application. The amount being sought for recovery ($1.117 billion) is the sum of the regulated hydroelectric total at Ex. H1-2-1, Table 1, col. (e), line 13 ($205.4M) and the nuclear total at Ex. H1-2-1, Table 2, col. (e), line 19 ($911.6M).[1]

As set out in the two tables, calculating the amounts recoverable in this application starts with the 2017 audited year end balance (col. (a)), removes previously OEB-approved amortization (col. (b)) and amounts deferred to future applications (col. (d)), to arrive at amounts proposed for recovery in this application (col. (e)).

[1] OPG is also seeking recovery of income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance, as discussed in Ex. F1-1-1. These amounts are presented at Ex. H1-2-1 Table 1, col. (e), line 14 and Ex. H1-2-1 Table 2, col. (e), line 20.

H-CCC-5

Interrogatory

Reference:
Ex. H1/T2/S1 and Ex. A2/T1/S1/ Attachment 3

Please provide a schedule which sets out the Payment Amounts and Payment Riders for each year 2014-2021 in the same format as provided at page 10 of the Stakeholder Presentation.

Response

The requested schedule of Payment Amounts and Payment Riders for each year from 2014-2021 is provided in Attachment 1 to this response.

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.

H-CME-1

Interrogatory

Reference:
Exhibit H1, Tab 1, Schedule 1, pages 12 and 13 of 26

At Exhibit H1, Tab 1, Schedule 1, pages 12 and 13, OPG states of the Gross Revenue Charge Variance Account: "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."

(a) To the best of OPG's information, what is the current status of the Ministry's decision on this matter?

(b) Does OPG anticipate recording any amounts in this account in the near future?

Response

(a) To the best of OPG's information, the decision by the Ministry remains outstanding.

(b) No. Please refer to answer (a)

H-CME-2

Interrogatory

Reference:
Exhibit H1, Tab 1, Schedule 1, Attachment 3, page 7 of 11

At Exhibit H1, Tab 1, Schedule 1, page 20 of 26, OPG states: "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 licensing fees."

(a) What was the cause of the variance between the actual spend to maintain the license, and the reference amount of $0?

Response

The reference amount of $0 is discussed at EB-2013-0321, Ex. F2-8-1, where it states:

> The Government of Ontario has not yet determined a cost recovery mechanism for new nuclear. When it does, OPG will develop its future applications accordingly. For the purposes of this application, OPG has not made any assumption on the form of that mechanism and therefore has not included any costs for the project in the test period.

Ontario's 2013 Long-Term Energy Plan was released on December 2, 2013 and included the following statement:

> Ontario will not proceed at this time with construction of two new nuclear reactors at the Darlington site. However, the Ministry of Energy will work with OPG to maintain the site license granted by the Canadian Nuclear Safety Commission (CNSC).

As noted in the preamble, OPG has continued to incur costs to maintain the license granted by the CNSC, which is the cause of the variance to the reference amount of $0.

H-CME-3

Interrogatory

Reference:
Exhibit H1, Tab 2, Schedule 1, page 3 of 5

Exhibit H1, Tab 2, Schedule 1, page 3 describes the recovery periods being proposed by OPG. Specifically, OPG states that with regard to the bulk of the accounts: "A three-year recovery period would be consistent with the recovery period for D&V account balances and interim period revenue shortfall approved by the OEB in EB-2016-0152 (i.e., 34 months from March 1, 2018 to December 31, 2020). A three-year recovery period also matches the remaining portion of the current five-year rate-setting term ending on December 31, 2021, reducing complexity in future rate-setting periods by reducing the impact of previously approved D&V account recoveries."

(a) Did OPG consider any other possible recovery periods, either shorter or longer than the three years proposed in the application?
(b) If the answer to (a) above is yes, what recovery periods were considered, and why was three years more appropriate than other alternatives?
(c) If the answer to (a) above is no, why not?
(d) What consideration did OPG give to rate impacts when determining that three years was the appropriate recovery period for the bulk of the accounts?

Response

(a), (b), (c), (d)

Yes, OPG considered other possible recovery periods to the three-year period proposed in the application for the majority of accounts, with the exception of those accounts for which recovery periods were previously established by the OEB.[1]

OPG proposes a three-year recovery period for the majority of accounts for the reasons cited in the preamble to this interrogatory. OPG did not consider a shorter recovery period than the proposed three years; however, to mitigate bill impacts during the 2019 to 2021 period, OPG considered a longer recovery period for some of the larger balances proposed for recovery. For the purposes of this longer timeframe, OPG proposes an eight-year recovery period to align with the end of the next five-year rate-setting term (i.e., 2022 to 2026) and consistent with the prior recovery periods approved by the OEB for OPG's Pension and OPEB Cost Variance Account balances, as noted in Ex. H1-2-1 pp. 3-4.

OPG is of the view that its proposed recovery periods provide a reasonable balance between intergenerational equity considerations and customer bill impacts, while aligning with rate periods for regulatory efficiencies.

[1] Ex. H1-2-1, p. 4, lines 14 – 23.

H-Energy Probe-1

Interrogatory

Reference:

Exhibit F1, Tab 1, schedule 1, page 10. OPG states that " [t]he majority of utilities' rates reflect the recovery of pension and OPEB costs on an accrual basis".

Please provide a list of the minority of utilities whose rates reflect the recovery of pension and OPEB costs on a cash basis.

Response

The reference above reflects the results of the analysis of utility practices for recovery of pension and OPEB costs prepared by KPMG to support the OEB's generic consultation in EB-2015-0040[1], and was not determined by OPG. As such, OPG does not have the information collected in support of KPMG's analysis, and as being requested above.

In EB-2015-0040, KPMG noted that the "majority"[2] of utilities use the accrual accounting method to recover pension and OPEB costs. For pensions, the only utility specifically identified as using a method other than accrual is Hydro One Networks Inc., which uses the funding method whereby employer contributions to the registered pension plan are recovered through rates, as noted at footnote 14 of Ex. F1-1-1.[3] For OPEBs, KPMG determined that "a few entities"[4] use the cash payments method for OPEB cost recovery. The EB-2015-0040 Report similarly noted that "[m]ost Ontario energy utilities recover their OPEB costs on the accrual

[1]As discussed at Ex. F-1-1-1, p. 4, lines 12-16.
[2] EB-2015-0040, KPMG Presentation on P & OPEB Costs – Alternatives Identified, dated July 19-20, 2016, p.3 ("KPMG Presentation").
[3] For electricity distributors in Ontario who are members of the OMERS pension plan, the employer contributions made to the plan are equal to the accrual accounting cost. See EB-2015-0040, Report of the OEB, *Regulatory Treatment of Pension and Other Post-employment Benefits* 10 *(OPEBs) Costs* (the "Report"), dated September 14, 2017, p.6.
[4] KPMG Presentation, page 3.

method."[5] The specific identities of these utilities were not provided in the KPMG Presentation or in the Report.

[5] Report, p. 7.

H-Energy Probe-2

Interrogatory

Reference:

Exhibit F1, Tab 1, schedule 1, page 10.

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

a) Considering that most of the utilities regulated by the OEB are municipally owned small distributors and not government owned very large power generators like OPG, and that there are significant differences among various utilities why does OPG believe that all utilities regulated by the OEB should have the same effective treatment?

b) Why is OPG concerned that some utilities could have a financial advantage over OPG? Is OPG facing or expecting to face competitive pressures from other OEB regulated utilities? Please explain indicating which utilities are a competitive threat to OPG.

Response

a) OPG believes that consistency in rate-setting based on regulatory principles promotes stability, predictability, and fair outcomes. Therefore, in the absence of utility-specific circumstances, OPG believes consistent application of policy is appropriate.

OPG is different from other entities regulated by the OEB in many respects, as is any other utility when compared to others, whether based on ownership structure or relative size as suggested by the question above, or otherwise. Factors such as these are not tied to the regulatory principle of fairness and, in OPG's view, do not support a conclusion that OPG should be treated differently with respect to the application of the New Differential Account to the recoveries of pension and OPEB costs for the period prior to January 1, 2018.

b) The question misinterprets the referenced evidence. The evidence does not refer to any competitive disadvantage between OPG and other regulated utilities. Rather, the referenced evidence demonstrates that, if the New Differential Account were applied to recoveries of the Interim Account balances recorded as of December 31, 2017, OPG would incur a financial penalty that utilities without an Interim Account would not incur.

H-Energy Probe-3

Interrogatory

Reference:
Exhibit F1, tab 1, schedule 1, pages 6 and 7

Please provide a table showing the forecast of the impact of the OPG's proposed implementation of OEB policy on OPG earnings for each year from January 1, 2019 to December 31, 2021.

Response

The additional interest expense that OPG would be required to incur in respect of the period prior to the January 1, 2018 implementation date[1] is provided in Ex. L-H-Staff-10. Chart 1 below shows the interest amounts and associated impact on earnings before taxes for each year from January 1, 2019 to December 31, 2021, using OPG's proposed clearance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account. However, as shown in Ex. L-H-Staff-10, interest costs would continue to increase annually beyond 2021, continuing to decrease earnings.

Chart 1

Description	2019	2020	2021	Total
Interest Expense	$1.3M	$3.9M	$6.4M	$11.6M
Earnings	($1.3M)	($3.9M)	($6.4M)	($11.6M)

[1] EB-2015-0040, Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, p. 11.

H-Energy Probe-4

Interrogatory

Reference:
Exhibit H1, tab 1, schedule 1

Compared to other utilities regulated by the OEB, OPG has a relatively large number of complicated deferral and variance accounts with varying recovery periods. Please provide a table listing all OPG deferral and variance accounts, showing the docket number of the OEB decision that approved each account, a short description of the purpose of the account, the recovery period, the total balance that is being recovered from ratepayers or credited to ratepayers and the expected annual amount if applicable, and the year in which each account will be terminated. Please identify accounts that are expected to continue for an indefinite period and the year in which OPG will be re-applying for their re-approval. Please include any OPG proposed accounts in the table.

Response

The summary table below contains information available in the account descriptions at Ex. H1-1-1.[1] The incremental annual amortization amount proposed in this application, if applicable, can be found at Ex. H1-2-1, Tables 1 and 2, columns (g), (h), and (i).

The accounts are currently in effect pursuant to the EB-2016-0152 Payment Amounts Order and the EB-2018-0002 Decision and Order and none have an approved termination date. Beyond this, OPG declines to provide the requested information on expected termination or re-approval dates as OPG is not seeking in this application the termination or approval of any

[1] The summary table contains information available in the account descriptions at Ex. H1-1-1 with the exception of the Impact Resulting from Changes to Pickering End-of-Life Dates (December 31, 2017) Deferral Account, which was established subsequent to December 31, 2017 (EB-2018-0002) but has been included in the summary table below.

deferral or variance account. This information is outside the scope of this application and is not relevant to the determination of issues or approvals being sought as part of this application.

Account	**Original Approval Docket Number**	**Summary Account Purpose**	**Proposed Amount Recoverable in Current Application ($M)[2]**	**Proposed Recovery Period (months)[3]**
Hydroelectric Water Conditions Variance Account	EB-2007-0905	Records the financial impact of differences, including changes in gross revenue charge ("GRC") costs and other related costs[4], between the actual production amount for regulated hydroelectric facilities and the reference production values, arising from changes in actual water conditions. The account applies to the previously regulated hydroelectric facilities and the 21 newly regulated hydroelectric facilities identified in EB-2016-0152 Ex. H1-1-1, Attachment 3.	(132.9)	36
Ancillary Services Net Revenue Variance Account	EB-2007-0905	Separated into Hydroelectric and Nuclear sub-accounts. Records differences between actual ancillary net revenues for the regulated hydroelectric and nuclear facilities and the forecast amounts reflected in the approved revenue requirement.	Hydro: (31.8) Nuclear: 2.4	Hydro: 36 Nuclear: 36
Hydroelectric Incentive Mechanism Variance Account	EB-2010-0008	Records a credit to ratepayers of 50% of hydroelectric incentive mechanism revenues above an OEB-specified threshold.	0.0	36
Hydroelectric Surplus Baseload Generation	EB-2010-0008	Records the financial impact of foregone production at the regulated hydroelectric facilities due to surplus baseload generation conditions at	278.0	36

[2] EB-2018-0243, Ex. H1-2-1, Tables 1 and 2, col. (e)
[3] EB-2018-0243, Ex. H1-2-1 Tables 1 and 2, col. (f)
[4] The account also records any variations from the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal as well as any variances from the amounts payable to the Government of Quebec for water rentals that were reflected in the revenue requirement approved by the OEB in EB-2013-0321.

Variance Account		the previously regulated hydroelectric facilities and the 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.[5]		
Income and Other Taxes Variance Account	EB-2007-0905	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	Hydro: 0.0 Nuclear: 5.7	Hydro: 36 Nuclear: 36

[5] The account also records any variations, as a result of forgone production due to SBG conditions, in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal as well as any variances from the amounts payable to the Government of Quebec for water rentals that were reflected in the revenue requirement approved by the OEB in EB-2013-0321.

		• 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).		
Capacity Refurbishment Variance Account	EB-2007-0905	Pursuant to O. Reg. 53/05, 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.	0.0	N/A
Pension and OPEB Cost Variance Account	EB-2011-0090	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. Outstanding balances represent amounts previously approved for recovery by the OEB in EB-2012-0002 and EB-2014-0370.	Hydroelectric – Future: 6.3 Hydroelectric – Post 2012 Additions: 14.8 Nuclear Future: 128.8 Nuclear Post 2012 Additions: 282.7	Hydroelectric – Future:72 Hydroelectric – Post 2012 Additions: 30 Nuclear Future: 72 Nuclear Post 2012 Additions: 30

Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	EB-2009-0174	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.	12.2	36
Gross Revenue Charge Variance Account[6]	EB-2013-0321	Records the cost impact of a gross revenue charge reduction under O. Reg. 124/02, once approved by the Ontario Ministry of 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.	0.0	N/A
Pension & OPEB Cash Payment Variance Account	EB-2013-0321	Records the difference between OPG's actual registered pension plan contributions and 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.	Hydro: (30.1) Nuclear: (137.4)	Hydro: 36 Nuclear: 36
Pension & OPEB Cash Versus Accrual Differential Deferral Account	EB-2013-0321	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	Hydro: 83.2 Nuclear: 530.5	Hydro: 96 Nuclear: 96

[6] The account is not listed in Ex. H1-1-1 Tables 1-3 and Ex. H1-2-1 Table 1 as it has had no activity since inception.

		benefit plan) attributed to OPG's prescribed generating facilities.		
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	EB-2014-0369	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 Decision and Order.	5.8	36
Nuclear Liability Deferral Account	EB-2007-0905	Pursuant to O. Reg. 53/05, records the revenue requirement impact on the prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement measured against the forecast impact reflected in the revenue requirement approved by the OEB.	18.6	36
Nuclear Development Variance Account	EB-2007-0905	Pursuant to O. Reg. 53/05, 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.	0.2	36
Bruce Lease Net Revenues Variance Account	EB-2007-0905	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.	<u>Sub Accounts:</u> Derivative: (0.8) Non-Derivative: 168.4	<u>Sub Accounts:</u> Derivative: 36 Non-Derivative: 96
Nuclear Deferral and Variance Over/Under Recovery	EB-2009-0174	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	30.6	36

Variance Account		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.		
Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	EB-2015-0374	Records the revenue requirement impact arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for Bruce, Pickering and Darlington nuclear generating stations that became effective December 31, 2015.[7]	(103.4)	36
SR&ED ITC Variance Account	EB-2016-0152	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.	(3.4)	36
Fitness for Duty Deferral Account	EB-2016-0152	Records costs related to implementing the Canadian Nuclear Safety Commission's Fitness for Duty program.	0.0	N/A
Rate Smoothing Deferral Account	EB-2016-0152	Pursuant to O. Reg. 53/05, 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.	0.0	N/A
Impact Resulting from Changes to Pickering End-of-Life Dates (December 31, 2017) Deferral Account	EB-2018-0002	Records the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for Pickering prescribed nuclear facilities effective December 31, 2017.[8]	N/A	N/A

[7] 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.
[8] Ibid.