

CCC Interrogatory #099

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 10

Preamble:

The Ancillary Services Net Revenue Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and has been approved in all subsequent OPG applications. This account recognizes that ancillary services revenues are difficult to forecast accurately, with variability in actual ancillary revenues reflecting changing demand and system operating requirements.

Question(s):

Given the stated issues in forecasting ancillary services revenue as the reason for the account, is OPG opposed to maintaining the nuclear subaccount open in case the current forecast turns out to be inaccurate?

Response

Yes.

CCC Interrogatory #100

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, pp. 19-20

Question(s):

Please provide a detailed calculation supporting the referenced non-capital costs for the 2027-2031 period for the Hydroelectric CRVA.

Response

Refer to Chart 1 below for a breakdown of the proposed 2027-2031 reference amount for the regulated hydroelectric non-capital costs for the Capacity Refurbishment Variance Account ("CRVA").

Chart 1 – 2027-2031 CRVA Reference Amount Breakdown for Regulated Hydroelectric Non-Capital Costs

Particulars¹	Amount (\$M)
Sir Adam Beck Complex	10.9
Niagara Region (excluding Sir Adam Beck Complex)	3.5
Eastern Region	5.5
Western Region	1.7
Small Hydro Redevelopment	3.7
Total	25.3

¹ Amounts included within Ex. F1-3-1, Table 1, col. (I), lines 5, 6, and 10.

CCC Interrogatory #101

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, pp. 38-39

Question(s):

With respect to the Nuclear Development Variance Account, please provide the year-end 2024 balance associated with potential new nuclear generation facilities other than the DNNP and describe the activities that underpin these costs.

Response

Refer to Ex. H1-1-1, Table 1, line 19, col. (c) for the year-end 2024 balance in the Nuclear Development Variance Account that is not related to the DNNP. For the reasons set out in Ex. L-H1-Staff-260 part b), OPG declines to describe the activities that underpin these costs.

CCC Interrogatory #102

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 41

Question(s):

- a) Please provide the total amount of interest (at OPG's long-term debt rate) that will be recorded in the Rate Smoothing Deferral Account over the 10-year disposition period.
- b) Please provide the total amount of interest (at OPG's long-term debt rate) that will be recorded in the Rate Smoothing Deferral Account based on (i) a 3-year disposition period; and (ii) a 5-year disposition period.

Response

- a) Refer to Ex. L-H1-Staff-256, Chart 1.
- b) Refer to Ex. L-H1-Staff-256, Chart 4 and Chart 3 for (i) and (ii), respectively.

CCC Interrogatory #103

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, pp. 44-45

Question(s):

Please provide a detailed breakdown of the costs recorded in the Pickering Closure Costs Deferral Account. As part of the response, please explain the reason that each of the costs was incurred.

Response

Chart 1 provides the requested breakdown of the costs recorded in the Pickering Closure Costs Deferral Account, as of December 31, 2024 (refer to Ex. F4-3-1, pp. 11-13). The majority of costs were booked to the account in 2022 and in 2023 (\$1.8M and \$3.4M respectively) and are for internal labour to support the described activities except as otherwise noted.

Chart 1 – Breakdown of Costs in Pickering Closure Costs Deferral Account

Department	Costs Recorded as of Dec 31, 2024 (\$M)	Description
Human Resources	6.2	• Workforce planning efforts, including staffing, retention and risk management strategies. • Downsizing, redeployment and labour relations planning, negotiations, and dispute/grievance management. • Change management, communications and organizational design activities. • Purchased services to support workforce skills assessment and recruitment efforts.
Law	0.6	• External legal counsel in support of labour relations matters.
Other	0.3	• Incremental administrative work to support redeployment processes and retention objectives. • Workforce planning tools.

CCC Interrogatory #104

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, pp. 44-45

Question(s):

With respect to the sale of Kipling Site, please provide the detailed calculation for each of the initial after-tax gain (\$12.3M) and the subsequent gain in 2023 (\$2.5M) in a format that allows comparability between these two calculations.

Response

OPG interprets that the “initial after-tax gain” in the question refers to the agreed upon balance of (\$12.7M) for disposition in the Sale of Unprescribed Kipling Site Deferral Account as of December 31, 2022 pursuant to the EB-2023-0336 OEB-approved settlement proposal (EB-2023-0336 Decision and Order, Appendix A, Schedule B, p. 16), as shown at Ex. H1-1-1, Table 1a, line 47. The settlement proposal notes that this amount represents 50% of the 23% of the after-tax gain recognized by OPG in 2022 associated with sale of the Kipling site, and provides that any after-tax gain on such sale recognized by OPG during the 2023-2026 period is subject to the same treatment (EB-2023-0336 Decision and Order, Appendix A, Schedule B, p. 16). As the settlement proposal does not include a specific calculation, OPG is unable to provide it.

In Chart 1 below, OPG provides the calculation of the (\$2.5M) amount recorded in the Unprescribed Kipling Site Deferral Account recorded during 2023 pursuant to the above settlement terms. This calculation is performed in the same manner as in EB-2023-0336, Ex. L-H-SEC-02, part c).

**Chart 1 – Calculation of Amounts Recorded in Sale of Unprescribed Kipling
Site Deferral Account in 2023¹**

Line	Description	2023
1	Proceeds from Sale	34.3
2	Less: Commission and transaction costs	0.0
3	Net proceeds from sale	34.3
4	True-up Adjustments	4.1
5	Pre-tax gain on sale (line 3 - line 4)	30.3
6	Less: Tax expense	8.7
7	After-tax gain on sale	21.5
8	Per EB-2023-0336 settlement	23%
9		5.0
10	Per EB-2023-0336 settlement	50%
11	Amount recorded in deferral account	2.5

¹ Numbers may not calculate due to rounding.

CCC Interrogatory #105

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 50

Question(s):

- a) Please provide the estimated cumulative earnings sharing amount for the 2022-2025 period based on most recent actuals. As part of the response, please provide the detailed calculation.
- b) Please provide a detailed discussion of the estimated 4.7% ROE in 2026. As part of the response, please confirm that the estimated 2026 ROE excludes all DNNP-related expenditures.

Response

- a) Refer to Ex. L-H1-VECC-015 and Ex. L-H1-SEC-212.
- b) The 2026 forecast ROE is 5.63%, per corrected Ex. I1-1-1, Table 5, line 24. OPG confirms that the forecast 2026 ROE excludes all DNNP-related expenditures.

The 2026 forecast ROE is lower compared to the OEB-approved ROE, mainly from activities at OPG's nuclear facilities, due to the following key drivers:

- Lower Darlington production of 0.9 TWh, which, as discussed in Ex. E2-1-2, reflects a Unit 3 planned outage shift from 2027 to 2026, with an extended duration to conduct steam generator primary moisture separator replacements, partly offset by the forecast earlier return to service of Unit 4 from refurbishment. Refer to Ex. D2-1-3, pp. 13-15 for Darlington Steam Generator Primary Moisture Replacements projects and Ex. D2-2-1 and related exhibits for the Darlington Refurbishment Program.
- Higher Darlington Outage OM&A costs as a result of the Unit 3 planned outage shifting from 2027 to 2026, partly offset by reduced Cyclical Outage costs for Unit 4 due to its forecast earlier return to service from refurbishment. Refer to Ex. F2-4-2, p. 5 for further discussion.
- Higher Base OM&A costs at Darlington, largely due to higher labour cost escalation than forecasted in EB-2020-0290, reflecting collective bargaining process outcomes in a high inflationary environment and from the overturning of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), as discussed in Ex. F2-2-2, p.4 and Ex. F4-3-1, Section 6.2.1.

- 1 • Higher Corporate Support Project OM&A costs, primarily due to projects in
2 Corporate & Technology Services, including the Enterprise System
3 Modernization projects (e.g., Asset Management, Finance ERP and Supply
4 Chain ERP), discussed in Ex. D3-1-1 and Ex. D3-1-2.

CCC Interrogatory #106

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 60

Question(s):

Please provide the proposed materiality threshold that would be applied with respect to a single “change of law” that occurs during the 2027-2031 period for the purposes of determining whether the impacts of that change would be subject to refund/recovery in the Change of Laws Deferral Account.

Response

The Applicants propose to determine materiality for the purposes of the Change of Laws Deferral Account (OPG) and the Change of Laws Deferral Account (DNNP) using the proposed materiality thresholds of \$20M for OPG and \$10M for DNNP LP under the respective rate-setting frameworks, as set out in Ex. A1-3-2, Section 4.3, on an annualized revenue requirement or revenue basis, as applicable.

CCC Interrogatory #107

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 65

Question(s):

Please explain the basis for the application of OPG's long-term debt rate on the Payment Amount Shaping Deferral Account in the context of the proposed recovery of the balance, through inclusion directly in the nuclear revenue requirement, in the year after the balance is recorded. Please advise whether there is any regulation/legislation that requires interest amounts to be recorded at OPG's long-term debt rate.

Response

The proposal to record interest on the balance of the Payment Amount Shaping Deferral Account at OPG's long-term debt rate to be approved by the OEB was based on the treatment of OPG's Rate Smoothing Deferral Account, given that there are some similarities between the two accounts.

There is no regulation or legislation requiring such interest amounts to be recorded at OPG's long-term debt rate.

CCC Interrogatory #108

Interrogatory

Reference:

Exhibit H1, Tab 1, Schedule 1, p. 72

Question(s):

Please provide a table that lists all the deferral and variance accounts that are currently in place and proposed for the 2027-2031 period and the type of interest that applies (i.e., OEB policy interest rate for DVAs, OPG's long-term debt rate, etc.).

Response

See Chart 1 below.

Chart 1: List of Existing and Proposed DVAs and Interest Applied

Account	Type of Interest
	<i>* Interest rate basis established by O. Reg. 53/05</i>
OPG:	
Hydroelectric Water Conditions Variance Account	OEB Prescribed Rate
Ancillary Services Net Revenue Variance Account	OEB Prescribed Rate
Hydroelectric Incentive Mechanism Variance Account	OEB Prescribed Rate
Hydroelectric Surplus Baseload Generation Variance Account	OEB Prescribed Rate
Income and Other Taxes Variance Account (OPG)	OEB Prescribed Rate
Capacity Refurbishment Variance Account	OEB Prescribed Rate
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	OEB Prescribed Rate
Pension and OPEB Cost Variance Account (OPG)	No Interest
Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Primary and Contra Sub-Accounts, and Carrying Charges Sub-Account	No Interest
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	OEB Prescribed Rate
Gross Revenue Charge Variance Account	OEB Prescribed Rate
Nuclear Liability Deferral Account	No Interest
Nuclear Development Variance Account	OEB Prescribed Rate
Bruce Lease Net Revenues Variance Account	OEB Prescribed Rate
Fitness for Duty Deferral Account	OEB Prescribed Rate
SR&ED ITC Variance Account (OPG)	OEB Prescribed Rate
Pickering Closure Costs Deferral Account	OEB Prescribed Rate
Nuclear Deferral and Variance Over/Under Recovery Variance Account	OEB Prescribed Rate
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account	No Interest
Earnings Sharing Deferral Account	OEB Prescribed Rate

Impact for IFRS Deferral Account	No interest
Pickering B Variance Account	OEB Prescribed Rate
Pickering B Refurbishment Project Variance Account	OPG Long-Term Debt Rate*
Darlington New Nuclear Project Variance Account	OPG Long-Term Debt Rate*
Pension & OPEB Cash Payment Variance Account	OEB Prescribed Rate
Pension & OPEB Cash Versus Accrual Differential Deferral Account	No Interest
Clarrington Corporate Campus Deferral Account	OEB Prescribed Rate
Sale of Unprescribed Kipling Site Deferral Account	No Interest
Rate Smoothing Deferral Account	OPG Long-Term Debt Rate*
Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	No Interest
Incremental Cloud Computing Arrangement Implementation Costs Deferral Account	OEB Prescribed Rate
Change of Laws Deferral Account (OPG)	OEB Prescribed Rate
Clean Electricity ITC Variance Account (OPG)	OEB Prescribed Rate
Global Hydroelectric Capital Variance Account	OEB Prescribed Rate
Payment Amount Shaping Deferral Account	OPG Long-Term Debt Rate
DNNP Nuclear Liability Deferral Account	No Interest
<u>DNNP LP:</u>	
Darlington New Nuclear Project Variance Account re Development	OEB Prescribed Rate
Darlington New Nuclear Project Variance Account re Capital Cost Amounts	OPG Long-Term Debt*
DNNP Generator Capital Structure Variance Account	OEB Prescribed Rate
Income and Other Taxes Variance Account (DNNP)	OEB Prescribed Rate
Pension and OPEB Cost Variance Account (DNNP)	No Interest
Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)	OEB Prescribed Rate
SR&ED ITC Variance Account (DNNP)	OEB Prescribed Rate
Impact for IFRS Deferral Account (DNNP)	No Interest
Clean Electricity ITC Variance Account (DNNP)	OEB Prescribed Rate
Impact of Change in Tax Status Variance Account (DNNP)	OEB Prescribed Rate
Change of Laws Deferral Account (DNNP)	OEB Prescribed Rate

SEC Interrogatory #204

Interrogatory

**Reference:
H1-1-1**

Question(s):

With respect to any proposed new or modified deferral or variance accounts, please provide draft Accounting Orders. For modified deferral or variance accounts, please provide the draft as a blackline against the current accounting order.

Response

Refer to Attachment 1 for draft Accounting Orders for new deferral and variance accounts proposed for OPG and DNNP LP in this proceeding. Refer to Attachment 2 for draft Accounting Orders for to the modified SR&ED ITC Variance Account (OPG) and Gross Revenue Charge Variance Account proposed by OPG.

Note that when the Gross Revenue Charge Variance Account was originally approved in EB-2013-0321, no accompanying Accounting Order was issued. Therefore, the draft Accounting Order included in Attachment 2 with respect to the proposed modifications to this account is not provided as a blackline against a current accounting order.

Change of Laws Deferral Account (OPG)
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the Change of Laws Deferral Account (OPG), effective January 1, 2027, to record impacts to costs and revenues for the regulated facilities resulting from legislative or regulatory changes (“change of laws”) to the extent these impacts are not already reflected in the approved revenue requirement and the approved production forecast, or another deferral or variance account, as applicable, and result in a financial impact for OPG’s prescribed facilities of \$20M or greater on an annualized basis.

Entry 1: Impact resulting from change of laws on revenue

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Revenue	x,xxx	x,xxx
CR/DR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx

To record the impact resulting from changes of laws on revenue.

Entry 2: Impact resulting from change of laws on capital costs

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

To record the impact resulting from changes of laws on depreciation, the associated impacts on the return on rate base, and any tax impacts.

Entry 3: Impact resulting from change of laws on non-capital costs

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from change of laws on non-capital expenses.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Change of Laws Deferral Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**Global Hydroelectric Capital Variance Account
Ontario Power Generation Inc.
Illustrative Accounting Order**

Scope of Account

OPG shall establish the asymmetrical Global Hydroelectric Capital Variance Account, effective January 1, 2027, to record a credit to ratepayers equal to the amount, if any, by which the total actual capital-related revenue requirement (“CRRR”) for the regulated hydroelectric facilities over the 2028-2031 period is lower than the forecast CRRR underpinning the capital factor used to set hydroelectric payment amounts, as assessed after the 2028-2031 period.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR Depreciation Expense	x,xxx	
DR Return on Rate Base	x,xxx	
DR Income Tax Expense	x,xxx	
CR Global Hydroelectric Capital Variance Account		x,xxx

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully refunded.

OPG shall file the balance in the Global Hydroelectric Capital Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Clean Electricity ITC Variance Account (OPG)
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the Clean Electricity ITC Variance Account (OPG), effective January 1, 2027, to record the revenue requirement differences between the actual Clean Electricity Investment Tax Credits ("CEITCs) received for the regulated facilities and such amount reflected in the OEB-approved payment amounts for OPG's hydroelectric and nuclear facilities, including the income tax impacts arising from such differences, to the extent these impacts are not already reflected in another deferral or variance account.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Clean Electricity ITC Variance Account	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Clean Electricity ITC Variance Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**Payment Amount Shaping Deferral Account
Ontario Power Generation Inc.
Illustrative Accounting Order**

Scope of Account

OPG shall establish the Payment Amount Shaping Deferral Account, effective January 1, 2027, to record OPG's payment amount shaping amounts approved by the OEB for the 2027-2031 rate term, such period being "the deferral period".

The offsetting annual payment amount shaping amounts shall be recorded monthly on a straight-line basis, such that a nil balance remains in the account at the end of the deferral period.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Payment Amount Shaping Deferral Account	x,xxx	x,xxx
CR/DR Revenue	x,xxx	x,xxx

OPG shall record interest on the balance in the account at the following OEB-approved long-term debt rates reflecting OPG's cost of long-term borrowing, compounded annually: 4.58% for 2027, 4.78% for 2028, 4.90% for 2029, 4.97% for 2030 and 4.98% for 2031.

OPG shall file the balance in the Payment Amount Shaping Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**DNNP Nuclear Liability Deferral Account
Ontario Power Generation Inc.
Illustrative Accounting Order**

Scope of Account

OPG shall establish the DNNP Nuclear Liability Deferral Account, effective January 1, 2027, to record the difference between: (i) the costs of OPG's nuclear facilities decommissioning and nuclear waste management liabilities ("nuclear liabilities") with respect to the Darlington New Nuclear Program ("DNNP") facilities, as reflected in OPG's audited annual financial statements approved by OPG's Board of Directors; and, (ii) the costs of the nuclear liabilities with respect to the DNNP facilities reflected in OPG's nuclear revenue requirement approved by the OEB.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR DNNP Nuclear Liability Deferral Account	x,xxx	x,xxx
CR/DR Asset Retirement Cost Depreciation Expense	x,xxx	x,xxx
CR/DR Used Fuel Storage and Disposal Variable Expense	x,xxx	x,xxx
CR/DR Low & Intermediate Level Waste Management Variable Expense	x,xxx	x,xxx
CR/DR Accretion Expense	x,xxx	x,xxx
CR/DR Earnings on Nuclear Funds	x,xxx	x,xxx
CR/DR Income Tax Expense		

OPG shall not record interest on the balance of this account.

OPG shall file the balance in the DNNP Nuclear Liability Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Pension and OPEB Cost Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Pension and OPEB Cost Variance Account (DNNP), effective January 1, 2027, to record the difference between (i) the pension and other post-employment benefit (“OPEB”) costs, plus related income tax payments, reflected in the revenue requirement approved by the OEB; and (ii) DNNP LP’s actual pension and OPEB costs, and associated income tax impacts, for the DNNP LP facilities.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Pension and OPEB Cost	x,xxx	x,xxx
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Pension and OPEB Cost Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall not record any interest on the balance of this account.

DNNP LP shall file the balance in the Pension and OPEB Cost Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP), effective January 1, 2027, to record the difference between the amounts approved for recovery or repayment in the DNNP LP deferral and variance accounts and the actual amounts recovered or repaid based on actual nuclear production and approved riders. The account shall also capture the transfer of balances remaining in other DNNP LP accounts as they expire from time to time.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Revenue	x,xxx	x,xxx
CR/DR Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

SR&ED ITC Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the SR&ED ITC Variance Account (DNNP), effective January 1, 2027, to record the difference between actual Scientific Research & Experimental Development investment tax credits ("SR&ED ITCs") attributed to the DNNP facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the DNNP LP revenue requirement approved by the OEB, including the tax on the difference. The forecast SR&ED ITCs included in the proposed DNNP LP revenue requirements for the 2027-2031 period are \$0.0M per year¹ or \$0.0M per month.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Income Tax Expense	X,xxx	X,xxx
CR/DR SR&ED ITC Variance Account (DNNP)	X,xxx	X,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the SR&ED ITC Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

¹ Ex. F4-2-1, Table 3g, line 21.

Income and Other Taxes Variance Account (DNNP)
DNNP LP
illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Income and Other Taxes Variance Account (DNNP) to record the financial impact on revenue requirement of the following:

- Any differences in income or capital taxes, or payments in lieu thereof, 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)), or other equivalent provincial legislation, as modified by the regulations under the *Electricity Act*, 1998, as applicable, 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 DNNP LP or the DNNP facilities under the *Assessment Act*, 1990;
- Any differences in income or capital taxes, or payments in lieu thereof, that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and,
- Any differences in income or capital taxes, or payments in lieu of thereof, that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to DNNP LP or the DNNP facilities or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Income and Other Taxes Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance of this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Income and Other Taxes Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**Impact for IFRS Deferral Account (DNNP)
DNNP LP
Illustrative Accounting Order**

Scope of Account

DNNP LP shall establish the Impact for IFRS Deferral Account (DNNP), effective January 1, 2027, to record financial impacts of transition to and implementation of International Financial Reporting Standards (“IFRS”) from United States Generally Acceptable Accounting Principles (“US GAAP”) in the event that DNNP LP adopts IFRS for financial reporting purposes.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Impact for IFRS Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Applicable Financial Statement Elements	x,xxx	x,xxx

Entries shall include, but not be limited to, unamortized gains/losses and past service costs/credits balances recorded for pension and other post-employment benefit plans in accumulated other comprehensive income/loss under US GAAP.

DNNP LP shall file the balance in the Impact for IFRS Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

DNNP LP shall not record any interest on the balance of this account.

Clean Electricity ITC Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Clean Electricity ITC Variance Account (DNNP), effective January 1, 2027, to record the revenue requirement differences between the actual Clean Electricity Investment Tax Credits (“CEITCs”) received for the DNNP facilities and such amount reflected in the OEB-approved payment amounts for the DNNP facilities, including the income tax impacts arising from such differences, to the extent these impacts are not already reflected in another deferral or variance account.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Clean Electricity ITC Variance Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered.

DNNP LP shall file the balance in the Clean Electricity ITC Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**Impact of Change in Tax Status Variance Account
DNNP LP
Illustrative Accounting Order**

Scope of Account

DNNP LP shall establish the Impact of Change in Tax Status Variance Account, effective January 1, 2027, to record the impact on regulatory income taxes or capital taxes reflected in the revenue requirement approved by the OEB of any changes to the income tax status of any DNNP LP's partners or as a result of a change in the partners of DNNP LP.

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Impact of Change in Tax Status Variance Account	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Impact of Change in Tax Status Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**Change of Laws Deferral Account (DNNP)
DNNP LP
Illustrative Accounting Order**

Scope of Account

DNNP LP shall establish the Change of Laws Deferral Account, effective January 1, 2027, record impacts to costs and revenues for the regulated facilities resulting from legislative or regulatory changes (“change of laws”) to the extent these impacts are not already reflected in the approved revenue requirement or the approved production forecast, or another deferral or variance account, as applicable, and result in a financial impact for the DNNP facilities of \$10M or greater on an annualized basis.

Entry 1: Impact resulting from change of laws on revenue

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Revenue	x,xxx	x,xxx
CR/DR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx

To record the impact resulting from changes of laws on revenue.

Entry 2: Impact resulting from change of laws on capital costs

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

To record the impact resulting from changes of laws on depreciation, the associated impacts on the return on rate base, and any tax impacts.

Entry 3: Impact resulting from change of laws on non-capital costs

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from change of laws on non-capital costs.

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Change of Laws Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

**SR&ED ITC Variance Account
Ontario Power Generation Inc.
Illustrative Accounting Order**

Basis of Approval

~~EB-2016-0152 Decision and Order, Pages 88 and 113.~~

Scope of Account

Effective ~~January~~ ~~June 1, 2014~~ ~~2027~~, the SR&ED ITC Variance Account will record the difference between actual SR&ED ITCs (attributed to the nuclear ~~and regulated hydroelectric~~ facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear ~~and regulated hydroelectric~~ revenue requirement approved by the OEB, including the tax on the difference. The forecast SR&ED ITCs included in the ~~approved~~ ~~proposed nuclear~~ revenue requirements for the ~~2014-2027-2023~~ ~~1~~ period are \$~~16.68~~ ~~4M~~ per year¹ or \$~~1.53~~ ~~9M~~ per month. ~~The forecast SR&ED ITCs included in the proposed regulated hydroelectric revenue requirement for 2027 is \$3.3M² or \$0.27 per month.~~

Entry

	<u>Debit</u>	<u>Credit</u>
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR SR&ED ITC Variance Account	x,xxx	x,xxx

To record the tax expense impact of the difference between SR&ED ITCs included in the approved nuclear ~~and regulated hydroelectric~~ revenue requirement and actual SR&ED ITCs.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

¹ ~~PAO Appendix A Tables 16 to 20, col (c), line 25~~ ~~Ex F4-2-1, Table 3d, line 29.~~

² ~~Ex. F4-2-1, Table 3b, line 22.~~

**Gross Revenue Charge Variance Account
Ontario Power Generation Inc.
Illustrative Accounting Order**

Scope of Account

Effective January 1, 2027, the Gross Revenue Charge Variance Account will record the following:

- The cost impact of Gross Revenue Charge (“GRC”) deductions, for eligible capacity of new, redeveloped, or upgraded stations, once approved by the Ontario Ministry of Natural Resources, pertaining to production increases at OPG’s regulated hydroelectric stations; and
- The revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to OPG’s prescribed hydroelectric assets under Section 92.1 of the *Electricity Act, 1998*.

Entry 1: Cost impact of GRC deductions

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR Gross Revenue Charge Expense	x,xxx	
CR Gross Revenue Charge Variance Account		x,xxx

Entry 2: Revenue requirement impact resulting from a legislative or regulatory change to the GRC rates or rules

<u>Entry</u>	<u>Debit</u>	<u>Credit</u>
DR/CR Gross Revenue Charge Expense	x,xxx	x,xxx
CR/DR Gross Revenue Charge Variance Account	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB’s prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Gross Revenue Charge Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

SEC Interrogatory #205

Interrogatory

Reference:

H1-1-1, p. 15

Question(s):

With respect to the Income and Other Taxes Variance Account:

- a) Please provide support documents regarding the entries related to the AIIP, and specifically, please provide CCA continuity schedules with and without AIIP.
- b) What is meant by the statement “Entry 1) continues to be calculated by applying the accelerated CCA rules to the forecast capital additions reflected in the EB-2013-0321 regulated hydroelectric revenue requirements, using the percentage of eligible actual regulated hydroelectric projects (for the corresponding year) as a proxy.” Please provide the full calculations in your explanation.
- c) Do any variances result from the impact of AIIP for CRVA eligible capital projects included in the CRVA or the Income Tax and Other Taxes Variances Account?
- d) Please provide a revised version of the 2023 and 2024 balances on the basis of actual in-service additions in those years. If the answer to part (c) is the AIIP impacts for CRVA eligible projects are recorded in the CRVA, then please exclude CRVA eligible in-service additions.

Response

- a) Attachment 1 provides the calculations supporting the 2023 and 2024 entries in the Income and Other Taxes Variance Account (OPG) related to capital cost allowance (“CCA”) differences arising from the accelerated investment incentive property (“AIIP”) rules for the regulated hydroelectric facilities (i.e., Entry (i) at Ex. H1-1-1, Table 6).¹

¹ In Attachment 1, Tables 2-3 and 5-6 the cost of acquisitions in Column (b) includes the cost of acquisition of AIIP, which is also separately shown in Column (c). The 50% of the amount of the non-AIIP property cost is calculated as 50% of the difference between the Column (b) and Column (c) and is included in the 50% Rule Column (g). Column (g) is then reduced by 50% of the AIIP cost in Column (c). CCA is then calculated based on the difference between Column (f) and Column (g), where Column (f) includes 100% of Column (b). This results in CCA being calculated using the pre-AIIP rules on non-AIIP property additions (i.e. at 50%) and based on the AIIP rules for AIIP property (i.e., three times the allowed amount under the non-AIIP rules for 2023 and two times the allowed amount under the non-AIIP rules for 2024).

- 1 b) The percentage of eligible actual regulated hydroelectric projects refers to the
2 percentage of actual regulated hydroelectric in-service additions for the
3 corresponding year's entry to the Income and Other Taxes Variance Account
4 (OPG) which are eligible for the AIIP rules. For 2023 and 2024, as shown in
5 Attachment 1, Tables 1 and 4, 100% of the regulated hydroelectric in-service
6 additions were eligible for the AIIP rules. To calculate the amounts of the account
7 entry, OPG applied this percentage to the difference between the forecast CCA
8 amounts based on the EB-2013-0321 regulated hydroelectric revenue
9 requirements and such recalculated forecast amounts assuming the AIIP rules had
10 applied in those years, in accordance with the EB-2020-0290 Payment Amounts
11 Order. This approach is unchanged from that reflected in the Income and Other
12 Taxes Variance Account (OPG) balances approved for disposition in EB-2020-
13 0290² and EB-2023-0326³.
14
- 15 c) As noted at Ex. H1-1-1, p. 16, footnote 20, the impact of AIIP rules on CRVA eligible
16 projects is recorded in the Capacity Refurbishment Variance Account ("CRVA"), not
17 the Income Other Taxes Variance Account (OPG).
18
- 19 d) OPG declines to provide the requested analysis, as it would not be appropriate to
20 use the postulated approach to determine the 2023 and 2024 entries in the Income
21 and Other Taxes Variance Account (OPG) related to CCA differences arising from
22 the AIIP rules for the regulated hydroelectric facilities. The postulated approach
23 relies on actual in-service additions in 2023 and 2024 that do not underpin the OEB-
24 approved reference amounts for the Income and Other Taxes Variance Account
25 (OPG) and would be contrary to the EB-2020-0290 Payment Amounts Order. The
26 EB-2020-0290 Payment Amounts Order prescribed that the variances in the
27 Income and Other Taxes Variance Account (OPG) for regulated hydroelectric
28 facilities are to be measured relative to reference amounts based on the forecast
29 income tax provision approved in EB-2013-0321, and not such actual amounts (EB-
30 2020-0290 Payment Amounts Order, p. 7, lines 14-23). Accordingly, the requested
31 analysis is not relevant and has no probative value.

² EB-2020-0290: Ex. H1-1-1, Section 5.5 and Ex. L-H1-01-Staff-326 part e).

³ EB-2023-0036, Ex. H1-1-1, Section 5.5.

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
H1-SEC-205
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Table 1
Calculation of Income and Other Taxes Variance Account for Regulated Hydroelectric Operations
Accelerated Investment Incentive CCA Impact (\$M)
December 31, 2023

Line No.		Note	2014	2015	Average
			(a)	(b)	(c)
1	Hydroelectric CCA in EB-2013-0321 with Accelerated CCA	1	238.8	229.3	234.0
2	Hydroelectric CCA in EB-2013-0321		227.1	218.6	222.9
3	Additional CCA (Line 1- Line 2)				11.2
4	Percentage Eligible	2			100%
5	2023 CCA Differences (Line 3 x Line 4)	3			11.2
6	Income Tax Impact	4			2.8
7	Addition to Variance Account	5			3.7

Notes:

- 1 Ex. L-H1-SEC-205 Tables 2 and 3, line 22, col. (k).
Percentage eligible was calculated as the ratio of the 2023 non-CRVA AIIP in-service additions to total 2023 non-CRVA in-service additions
- 2
- 3 Ex. H1-1-1, Table 6, line 1, col (a).
- 4 Ex. H1-1-1, Table 6, line 3, col (a).
- 5 Ex. H1-1-1, Table 6, line 5, col (a).

Numbers may not add due to rounding.

Table 2
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations with Accelerated CCA - 2023 AIIP Program (\$M)¹
Year Ending December 31, 2014

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	1	1,705.4	29.2	31.2	(4.4)	0.0	1,730.1	(15.7)	1,745.8	4%	0.0	69.8	1,660.3
2	1-rolling start	320.1	0.0	0.0	0.0	0.0	320.1	0.0	320.1	4%	0.0	12.8	307.3
3	1.1	19.2	0.6	0.6	(0.0)	0.0	19.8	(0.3)	20.1	6%	0.0	1.2	18.6
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	-	0.0
5	2	1,670.7	0.0	0.0	0.0	0.0	1,670.7	0.0	1,670.7	6%	0.0	100.2	1,570.4
6	3	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.8
7	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	-	0.0
8	8	43.7	19.1	19.1	(1.5)	0.0	61.3	(8.8)	70.2	20%	0.0	14.0	47.3
9	8-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	-	0.0
10	10	5.0	4.1	4.1	(0.3)	0.0	8.7	(1.9)	10.6	30%	0.0	3.2	5.5
11	12	5.1	6.0	6.0	(0.5)	0.0	10.6	0.0	10.6	100%	0.0	10.6	0.0
12	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	-	0.0
13	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	-	0.0
14	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	-	0.0
15	17	247.3	23.3	23.3	(1.8)	0.0	268.8	(10.7)	279.5	8%	0.0	22.4	246.4
16	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	-	0.0
17	42	3.9	0.2	0.2	(0.0)	0.0	4.1	(0.1)	4.2	12%	0.0	0.5	3.6
18	43.1	0.4	0.0	0.0	0.0	0.0	0.4	0.0	0.4	30%	0.0	0.1	0.3
19	43.2	6.1	0.0	0.0	0.0	0.0	6.1	0.0	6.1	50%	0.0	3.1	3.1
20	45	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	45%	0.0	0.1	0.1
21	50	0.9	0.3	0.3	(0.0)	0.0	1.2	(0.2)	1.4	55%	0.0	0.8	0.5
22	Total	4,028.8	82.8	84.8	(8.6)	0.0	4,103.0	(37.6)	4,140.6		0.0	238.8	3,864.1

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
H1-SEC-205
Attachment 1
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Table 3
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations with Accelerated CCA - 2023 AIIP Program (\$M)¹
Year Ending December 31, 2015

Line No.	Class	Undepreciated Capital Cost at Beginning of Year ²	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	1	1,660.3	37.1	37.1	(3.3)	0.0	1,694.1	(16.9)	1,711.0	4%	0.0	68.4	1,625.7
2	1-rolling start	307.3	0.0	0.0	0.0	0.0	307.3	0.0	307.3	4%	0.0	12.3	295.0
3	1.1	18.6	2.2	2.2	(0.2)	0.0	20.6	(1.0)	21.5	6%	0.0	1.3	19.3
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	-	0.0
5	2	1,570.4	0.0	0.0	0.0	0.0	1,570.4	0.0	1,570.4	6%	0.0	94.2	1,476.2
6	3	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.7
7	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	-	0.0
8	8	47.3	24.9	24.9	(3.6)	0.0	68.577	(10.6)	79.2	20%	0.0	15.8	52.7
9	8-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	-	0.0
10	10	5.5	5.3	5.3	(0.8)	0.0	10.1	(2.3)	12.3	30%	0.0	3.7	6.4
11	12	0.0	8.8	8.8	(1.2)	0.0	7.7	0.0	7.7	100%	0.0	7.7	0.0
12	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	-	0.0
13	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	-	0.0
14	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	-	0.0
15	17	246.4	28.2	28.2	(4.0)	0.0	270.6	(12.1)	282.6	8%	0.0	22.6	247.9
16	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	-	0.0
17	42	3.6	0.2	0.2	(0.0)	0.0	3.8	(0.1)	3.9	12%	0.0	0.5	3.3
18	43.1	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	30%	0.0	0.1	0.2
19	43.2	3.1	0.0	0.0	0.0	0.0	3.1	0.0	3.1	50%	0.0	1.5	1.5
20	45	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.0	0.0
21	50	0.5	1.1	1.1	(0.1)	0.0	1.4	(0.5)	1.9	55%	0.0	1.1	0.4
22	Total	3,864.1	107.7	107.7	(13.2)	0.0	3,958.6	(43.4)	4,002.1		0.0	229.3	3,729.4

Table 4
Calculation of Income and Other Taxes Variance Account for Regulated Hydroelectric Operations
Accelerated Investment Incentive CCA Impact (\$M)
December 31, 2024

Line No.		Note	2014	2015	Average
			(a)	(b)	(c)
1	Hydroelectric CCA in EB-2013-0321 with Accelerated CCA	1	234.1	224.3	229.2
2	Hydroelectric CCA in EB-2013-0321		227.1	218.6	222.9
3	Additional CCA (Line 1- Line 2)				6.4
4	Percentage Eligible	2			100%
5	2024 CCA Differences (Line 3 x Line 4)	3			6.4
6	Income Tax Impact	4			1.6
7	Addition to Variance Account	5			2.1

Notes:

- 1 Ex. L-H1-SEC-205 Tables 5 and 6, line 22, col. (k).
- 2 Percentage eligible was calculated as the ratio of the 2024 non-CRVA AIIP in-service additions to total 2024 non-CRVA in-service additions
- 3 Ex. H1-1-1, Table 6, line 2, col (d).
- 4 Ex. H1-1-1, Table 6, line 4, col (d).
- 5 Ex. H1-1-1, Table 6, line 5, col (d).

Numbers may not add due to rounding.

Table 5
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations with Accelerated CCA - 2024 AIIP Program (\$M)
Year Ending December 31, 2014

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	1	1,691.2	29.2	31.2	(2.4)	0.0	1,717.9		1,717.9	4%	0.0	68.7	1,649.2
2	1-rolling start	313.1	0.0	0.0	0.0	0.0	313.1		313.1	4%	0.0	12.5	300.6
3	1.1	19.2	0.6	0.6	(0.0)	0.0	19.8		19.8	6%	0.0	1.2	18.6
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	6%	0.0	-	0.0
5	2	1,670.7	0.0	0.0	0.0	0.0	1,670.7		1,670.7	6%	0.0	100.2	1,570.4
6	3	0.8	0.0	0.0	0.0	0.0	0.8		0.8	5%	0.0	0.0	0.8
7	6	0.0	0.0	0.0	0.0	0.0	0.0		0.0	10%	0.0	-	0.0
8	8	43.7	19.1	19.1	(1.5)	0.0	61.3		61.3	20%	0.0	12.3	49.1
9	8-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	20%	0.0	-	0.0
10	10	5.0	4.1	4.1	(0.3)	0.0	8.7		8.7	30%	0.0	2.6	6.1
11	12	5.1	6.0	6.0	(0.5)	0.0	10.6		10.6	100%	0.0	10.6	0.0
12	13	0.0	0.0	0.0	0.0	0.0	0.0		0.0	N/A	0.0	-	0.0
13	14.1	0.0	0.0	0.0	0.0	0.0	0.0		0.0	7%	0.0	-	0.0
14	14.1	0.0	0.0	0.0	0.0	0.0	0.0		0.0	5%	0.0	-	0.0
15	17	247.3	23.3	23.3	(1.8)	0.0	268.8		268.8	8%	0.0	21.5	247.3
16	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	8%	0.0	-	0.0
17	42	3.9	0.2	0.2	(0.0)	0.0	4.1		4.1	12%	0.0	0.5	3.6
18	43.1	0.4	0.0	0.0	0.0	0.0	0.4		0.4	30%	0.0	0.1	0.3
19	43.2	6.1	0.0	0.0	0.0	0.0	6.1		6.1	50%	0.0	3.1	3.1
20	45	0.2	0.0	0.0	0.0	0.0	0.2		0.2	45%	0.0	0.1	0.1
21	50	0.9	0.3	0.3	(0.0)	0.0	1.2		1.2	55%	0.0	0.7	0.6
22	Total	4,007.6	82.8	84.8	(6.6)	0.0	4,083.7	0.0	4,083.7		0.0	234.1	3,849.6

Table 6
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations with Accelerated CCA - 2024 AIIP Program (\$M)
Year Ending December 31, 2015

Line No.	Class	Undepreciated Capital Cost at Beginning of Year ¹	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	1	1,649.2	37.1	37.1	(5.3)	0.0	1,681.0		1,681.0	4%	0.0	67.2	1,613.8
2	1-rolling start	300.6	0.0	0.0	0.0	0.0	300.6		300.6	4%	0.0	12.0	288.5
3	1.1	18.6	2.2	2.2	(0.2)	0.0	20.6		20.6	6%	0.0	1.2	19.3
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	6%	0.0	-	0.0
5	2	1,570.4	0.0	0.0	0.0	0.0	1,570.4		1,570.4	6%	0.0	94.2	1,476.2
6	3	0.8	0.0	0.0	0.0	0.0	0.8		0.8	5%	0.0	0.0	0.7
7	6	0.0	0.0	0.0	0.0	0.0	0.0		0.0	10%	0.0	-	0.0
8	8	49.1	24.9	24.9	(3.6)	0.0	70.340		70.3	20%	0.0	14.1	56.3
9	8-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	20%	0.0	-	0.0
10	10	6.1	5.3	5.3	(0.8)	0.0	10.6		10.6	30%	0.0	3.2	7.4
11	12	0.0	8.8	8.8	(1.2)	0.0	7.7		7.7	100%	0.0	7.7	0.0
12	13	0.0	0.0	0.0	0.0	0.0	0.0		0.0	N/A	0.0	-	0.0
13	14.1	0.0	0.0	0.0	0.0	0.0	0.0		0.0	7%	0.0	-	0.0
14	14.1	0.0	0.0	0.0	0.0	0.0	0.0		0.0	5%	0.0	-	0.0
15	17	247.3	28.2	28.2	(4.0)	0.0	271.4		271.4	8%	0.0	21.7	249.7
16	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0		0.0	8%	0.0	-	0.0
17	42	3.6	0.2	0.2	(0.0)	0.0	3.8		3.8	12%	0.0	0.5	3.3
18	43.1	0.3	0.0	0.0	0.0	0.0	0.3		0.3	30%	0.0	0.1	0.2
19	43.2	3.1	0.0	0.0	0.0	0.0	3.1		3.1	50%	0.0	1.5	1.5
20	45	0.1	0.0	0.0	0.0	0.0	0.1		0.1	45%	0.0	0.0	0.0
21	50	0.6	1.1	1.1	(0.1)	0.0	1.5		1.5	55%	0.0	0.8	0.7
22	Total	3,849.6	107.7	107.7	(15.2)	0.0	3,942.1	0.0	3,942.1		0.0	224.3	3,717.8

SEC Interrogatory #206

Interrogatory

Reference:
H1-1-1, p. 26

Question(s):

Please provide a breakdown of the costs for the feasibility assessment.

Response

A breakdown of the costs incurred to complete the feasibility assessment for the Pickering Refurbishment Program is provided below.

Chart 1 – Feasibility Assessment Costs

Category	2022 (\$M)	2023 (\$M)
Labour	0.2	5.4
Purchased Services	-	11.5
Other	0.0	0.9
Total cost	0.2	17.8

SEC Interrogatory #207

Interrogatory

**Reference:
H1-1-1**

Question(s):

For each account for which recovery is sought, please provide an analysis similar to that provided in EB-2023-0336 JT1.8-1.10 regarding the difference between P50 in the most recent compensation study and OPG's actual internal labour costs sought for recovery. Please use an approach similar to that sought in F4-SEC-198 and provide all account-specific supporting calculations.

Response

Consistent with EB-2023-0336 Ex. JT1.8-1.10 and using a similar approach to Ex. L-F4-SEC-198, WTW has provided estimates based on the WTW benchmarking report shown in Ex. F4-3-1, Attachment 3, pp. 14-17 of the difference in non-capital costs recorded in the deferral and variance accounts described below and such costs at the P50 or P75 of market used in the study. The aggregate amounts estimated by WTW in this response range from \$5k - \$260k across all years and deferral and variance accounts. These amounts are well below the current and proposed materiality thresholds for OPG.

As discussed in Ex. F4-3-1, Attachment 3, p. 12, WTW considers the appropriate competitiveness to be within a +/- 10% range of the target market. While no further analysis to the +/- 10% range is presented in this response due to the immaterial amounts involved, OPG's overall benchmarking results are within the +/- 10% target market range in the majority of such scenarios, which would result in a difference of \$0 to the target market range.

Below OPG provides a response prepared by WTW with respect to such non-capital OPG labour costs recorded as part of balances sought for disposition in this Application in the following accounts: (i) the Clarington Corporate Campus Deferral Account, (ii) the Pickering Closure Costs Deferral Account, and (iii) the Fitness for Duty Deferral Account, as shown in Ex. H1-1-1, Table 1, col. (c), lines 37, 43, and 44, respectively, along with (iv) the Nuclear Development Variance Account – Darlington New Nuclear Program portion (refer to Ex. H1-1-1, Table 20), and (v) the nuclear portion of the Capacity Refurbishment Variance Account, excluding any costs related to the Darlington Refurbishment Program (refer to Ex. H1-1-1, Table 14).

As noted in Ex. D2-2-1, p. 2, lines 1-13, the EB-2020-0290 OEB-approved settlement proposal provides that the OEB will review the prudence of any DRP amounts sought by OPG in excess of the \$12.8B total budget approved in EB-2016-0152 and EB-2020-0290. As discussed at Ex. D2-2-1, p. 2, lines 16-18, OPG expects the final costs of the DRP to be within the \$12.8B. The Application also commits to not seek recovery of any unlikely final costs of the DRP that exceed the \$12.8B budget in any future proceedings, as noted in Ex. D2-2-1, p. 12, lines 6-8. As the DRP labour costs recorded within the CRVA are within this approved \$12.8B budget, OPG has not requested WTW to perform further analysis on the DRP amounts as part of this response.

The following part of this response has been prepared by WTW:

As noted at Ex. F4-3-1, Attachment 2, p. 13, total remuneration values in the WTW's benchmarking report should be interpreted with care and used to assess the competitiveness of OPG's total remuneration value relative to the market, rather than the competitiveness of OPG's costs. It is recommended that competitiveness be assessed by determining whether total remuneration levels fall within a reasonable range of market reference values, recommended as a range of +/- 10% of the market reference (refer to Ex. F4-3-1, p. 40 and associated Attachment 3, p.12), which is intended to reflect normal variation arising from the wide range of factors influencing individual compensation levels (refer to Ex. L-F4-SUP-018). In addition, to the extent the analysis is used in assessing the competitiveness of OPG's compensation costs, total direct compensation should be considered.

Charts 1 - 4 below provide an estimate of the dollar difference, by year, between total remuneration, excluding and including Hydro One shares, respectively, for each of PWU, Society and Management employee groups and the market 50th percentile ("P50") and the market 75th percentile ("P75") for Nuclear Authorized employees, for these groups for the OPG labour amounts recorded in the relevant accounts:

- CCCD Clarington Corporate Campus Deferral Account (Nuclear)
- PCCD Pickering Closure Costs Deferral Account (Nuclear)
- FFD Fitness for Duty (Nuclear)
- NDV NDVA – DNNP Portion Only (Nuclear)
- CRV Nuclear CRVA – Non-Capital (Nuclear) - Non - DRP

Chart 1.1 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P50, Excluding Hydro One Shares (p. 14 of WTW report) – CCDA, PCCD, FFD Accounts

	PWU (\$Thousands)			Society (\$Thousands)			Management (\$Thousands)			Total (\$Thousands)		
	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD
2024	-	\$30.8	-	-	\$9.9	\$10.5	-	(\$116.6)	(\$34.3)	-	(\$75.9)	(\$23.8)
2023	-	\$37.4	-	\$117.7	\$165.4	-	(\$60.3)	(\$281.3)	(\$39.2)	\$57.4	(\$78.5)	(\$39.2)
2022	-	\$0.6	-	-	\$5.6	-	-	(\$187.1)	(\$24.2)	-	(\$180.9)	(\$24.2)
2021	-	-	-	-	\$0.0	-	-	(\$73.4)	(\$17.0)	-	(\$73.4)	(\$17.0)

Chart 1.2 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P50, Excluding Hydro One Shares (p. 14 of WTW report) – NDV (DNNP) & CRV Accounts

	PWU (\$Thousands)		Society (\$Thousands)		Management (\$Thousands)		Total (\$Thousands)	
	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account
2024	\$4.3	(\$1.9)	\$121.4	\$106.3	(\$56.3)	(\$27.8)	\$69.4	\$76.6
2023	-	\$44.9	\$89.1	\$672.2	(\$42.9)	(\$447.9)	\$46.3	\$269.2
2022	-	(\$10.8)	-	\$95.8	-	(\$11.0)	-	\$74.0
2021	-	\$0.5	-	\$84.7	-	(\$9.7)	-	\$75.5
2020	-	-	-	\$11.8	-	(\$8.5)	-	\$3.3
2019	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-

Chart 2.1 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P50 Including Hydro One Shares (p. 15 of WTW report) – CCDA, PCCD, FFD Accounts

	PWU (\$Thousands)			Society (\$Thousands)			Management (\$Thousands)			Total (\$Thousands)		
	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD
2024	-	\$35.1	-	-	\$10.5	\$11.1	-	(\$116.0)	(\$34.1)	-	(\$70.3)	(\$23.0)
2023	-	\$42.8	-	\$126.1	\$177.2	-	(\$60.0)	(\$279.8)	(\$39.0)	\$66.1	(\$59.8)	(\$39.0)
2022	-	\$0.7	-	-	\$6.0	-	-	(\$186.0)	(\$24.0)	-	(\$179.3)	(\$24.0)
2021	-	-	-	-	\$0.0	-	-	(\$73.0)	(\$16.8)	-	(\$72.9)	(\$16.8)
2020	-	-	-	-	-	-	-	-	(\$4.2)	-	-	(\$4.2)
2019	-	-	-	-	-	-	-	-	(\$10.2)	-	-	(\$10.2)
2018	-	-	-	-	-	-	-	-	(\$13.5)	-	-	(\$13.5)

Chart 2.2 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P50 Including Hydro One Shares (p. 15 of WTW report) – NDV (DNNP) & CRV Accounts

	PWU (\$Thousands)		Society (\$Thousands)		Management (\$Thousands)		Total (\$Thousands)	
	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account
2024	\$5.0	(\$2.2)	\$129.4	\$113.4	(\$56.0)	(\$27.6)	\$78.4	\$83.5
2023	-	\$51.4	\$95.4	\$719.9	(\$42.6)	(\$445.5)	\$52.8	\$325.8
2022	-	(\$12.3)	-	\$102.3	-	(\$10.9)	-	\$79.1
2021	-	\$0.5	-	\$90.8	-	(\$9.6)	-	\$81.7
2020	-	-	-	\$12.7	-	(\$8.5)	-	\$4.2
2019	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-

Chart 3.1 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P75 (p. 16 of WTW report) – CCDA, PCCD, FFD Accounts

	PWU (\$Thousands)			Society (\$Thousands)			Management (\$Thousands)			Total (\$Thousands)		
	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD
2024	-	\$28.6	-	-	\$9.6	\$10.2	-	(\$122.2)	(\$35.9)	-	(\$83.9)	(\$25.8)
2023	-	\$34.7	-	\$114.1	\$160.3	-	(\$63.2)	(\$294.9)	(\$41.1)	\$50.9	(\$99.8)	(\$41.1)
2022	-	\$0.6	-	-	\$5.4	-	-	(\$196.7)	(\$25.4)	-	(\$190.7)	(\$25.4)
2021	-	-	-	-	\$0.0	-	-	(\$77.6)	(\$17.9)	-	(\$77.5)	(\$17.9)
2020	-	-	-	-	-	-	-	-	(\$4.5)	-	-	(\$4.5)
2019	-	-	-	-	-	-	-	-	(\$10.9)	-	-	(\$10.9)
2018	-	-	-	-	-	-	-	-	(\$14.7)	-	-	(\$14.7)

Chart 3.2 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P75 (p. 16 of WTW report) – NDV (DNNP) & CRV Accounts

	PWU (\$Thousands)		Society (\$Thousands)		Management (\$Thousands)		Total (\$Thousands)	
	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account
2024	\$4.0	(\$1.8)	\$117.9	\$103.3	(\$59.0)	(\$29.1)	\$62.9	\$72.4
2023	-	\$41.7	\$86.4	\$651.5	(\$44.9)	(\$469.5)	\$41.5	\$223.7
2022	-	(\$10.1)	-	\$93.0	-	(\$11.6)	-	\$71.3
2021	-	\$0.4	-	\$82.1	-	(\$10.2)	-	\$72.2
2020	-	-	-	\$11.4	-	(\$9.1)	-	\$2.4
2019	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-

Chart 4.1 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P75 Including Hydro One Shares (p. 17 of WTW report) – CCDA, PCCD, FFD Accounts

	PWU (\$Thousands)			Society (\$Thousands)			Management (\$Thousands)			Total (\$Thousands)		
	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD	CCCD Account	PCCD Account	FFD
2024	-	\$33.0	-	-	\$10.3	\$10.8	-	(\$121.5)	(\$35.7)	-	(\$78.3)	(\$24.9)
2023	-	\$40.1	-	\$122.4	\$172.1	-	(\$62.9)	(\$293.3)	(\$40.9)	\$59.5	(\$81.1)	(\$40.9)
2022	-	\$0.6	-	-	\$5.8	-	-	(\$195.7)	(\$25.3)	-	(\$189.2)	(\$25.3)
2021	-	-	-	-	\$0.0	-	-	(\$77.1)	(\$17.8)	-	(\$77.1)	(\$17.8)
2020	-	-	-	-	-	-	-	-	(\$4.5)	-	-	(\$4.5)
2019	-	-	-	-	-	-	-	-	(\$10.9)	-	-	(\$10.9)
2018	-	-	-	-	-	-	-	-	(\$14.5)	-	-	(\$14.5)

Chart 4.2 Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized at Market P75 Including Hydro One Shares (p. 17 of WTW report) – NDV (DNNP) & CRV Accounts

	PWU (\$Thousands)		Society (\$Thousands)		Management (\$Thousands)		Total (\$Thousands)	
	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account	NDV Account (DNNP)	CRV Account
2024	\$4.7	(\$2.1)	\$126.0	\$110.3	(\$58.7)	(\$29.0)	\$71.9	\$79.3
2023	-	\$48.1	\$92.7	\$699.3	(\$44.7)	(\$467.1)	\$48.0	\$280.3
2022	-	(\$11.6)	-	\$99.5	-	(\$11.5)	-	\$76.4
2021	-	\$0.5	-	\$88.2	-	(\$10.2)	-	\$78.5
2020	-	-	-	\$12.3	-	(\$9.0)	-	\$3.3
2019	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-

To respond to this interrogatory, WTW used a consistent methodology as set out in EB-2023-0336 Ex. JT1.8. Namely, for each applicable year, the market values and OPG information reflected in the results of WTW's benchmarking report (refer to Ex. F4-3-1, Attachment 3) were adjusted, and corresponding dollar differences calculated, based on the following steps and assumptions:

- Calculate the approximate actual headcount year over year changes for each year and employee group based on a percentage change from the 2024 headcount, as provided by OPG in Chart 5;
- Update the OPG benchmark data based on actual changes in salary, as provided by OPG in Chart 6 below;
- Adjust the market benchmark data based on median actual salary increases, as reported in WTW's Canadian Salary Budget Surveys from 2020 to 2025 and provided in Chart 7 below; and
- Proportionately adjust the resulting dollar differences to reflect the number of full-time equivalent employees within PWU, Society and Management groups underpinning the OPG labour amounts recorded in each of the accounts, as provided by OPG. Chart 8 below provides the number of such PWU, Society and Management full-time equivalent employees. For clarity, the proportion is calculated as the total number of full-time equivalent employees in each representation for each account relative to the total OPG population. This proportion is then applied to the dollar differences above market reference within the PWU, Society, and Management groups to get the resulting dollar differences for each representation for each of the accounts, where such dollar difference market reference is derived after extrapolation of the benchmarking results to the full OPG population (refer to Ex. L-F4-SEC-198, part b)).

Chart 5 – OPG Headcount Change Percentages (as a % of 2024)

OPG Group	OPG FTEs (as % of 2024 FTE)						
	2024 Actual	2023	2022	2021	2020	2019	2018
PWU	100%	99.2%	97.2%	99.0%	101.9%	102.2%	103.0%
Society	100%	88.4%	77.1%	78.2%	79.2%	83.3%	86.9%
Management	100%	87.0%	76.4%	75.5%	84.6%	88.3%	89.8%
Overall	100%	93.3%	86.5%	87.7%	90.7%	92.9%	94.9%

The percentage changes from 2024 and the corresponding year-over-year percentage changes in Chart 5 were derived directly from the sum of corresponding employee group line items for Nuclear:

- For the years 2018-2020: Ex. L-F4-03-Society-018, Attachment 1 from EB-2020-0290 (i.e., line 26 for Management, line 27 and line 32 for Society, and line 29 and line 31 for PWU)

- For the years 2020-2024: Ex. L-F4-CCMBC-005, Attachment 1 (i.e., line 19 for Management, line 20 and line 25 for Society, and line 22 and line 24 for PWU)

Chart 6 – OPG Wage Escalation

Segment	OPG Wage Escalation						
	2024 Actual	2023	2022	2021	2020	2019	2018
PWU	3.75%	3.50%	4.75%	3.50%	2.00%	2.00%	1.80%
Society	4.75%	3.25%	4.00%	2.80%	2.00%	2.00%	1.00%
Management	3.35%	2.89%	1.75%	1.57%	1.85%	1.70%	2.39%

Chart 7 – Market Escalation

	2019	2020	2021	2022	2023	2024
Market Salary Increase Assumption						
PWU	2.7%	2.9%	2.7%	3.0%	4.0%	3.5%
Society	2.7%	2.9%	2.7%	3.0%	4.0%	3.5%
Management	2.7%	2.9%	2.7%	3.0%	4.0%	3.5%

Note: Salary increase assumptions sourced from WTW's 2025 Dec Edition Canadian Salary Budget Survey | Natural Resources

Chart 8 – Number of Full-time Equivalent Employees for the Identified Accounts*

Recovery Account	Representation	OPG Full-time Equivalent Employees						
		2018	2019	2020	2021	2022	2023	2024
Clarington Corporate Campus Deferral (CCCD)	PWU						4.1	
	Society Management						1.5	
	Total						5.6	
Pickering Closure Costs Deferral (PCCD)	PWU					0.0	2.2	1.7
	Society Management				0.0	0.2	5.7	0.3
	Total				2.3	5.3	7.1	2.8
Fitness for Duty (FFD)	PWU							0.3
	Society Management	0.6	0.4	0.2	0.5	0.7	1.0	0.8
	Total	0.6	0.4	0.2	0.5	0.7	1.0	1.2
NDVA – DNNP Portion Only (NDV)	PWU							0.2
	Society Management						3.1	3.8
	Total						1.1	1.4
Nuclear CRVA – Non-Capital (CRV)	PWU				0.0	(0.6)	2.6	(0.1)
	Society Management			0.5	3.2	3.3	23.2	3.3
	Total			0.3	0.3	0.3	11.3	0.7
				0.8	3.5	3.0	37.2	3.9

***Note:** Numbers have been rounded to one decimal place and may round to 0.0 FTE

SEC Interrogatory #208

Interrogatory

Reference:

H1-1-1, p. 18

Preamble:

OPG proposed to defer the clearance of the hydroelectric CRVA balance to a future application, “which would provide the necessary details to support an assessment of the recoverability of any such amounts recorded over the full 2022-2026 period.”

Question(s):

- a) What is the December 31, 2024 and December 31, 2025 balance of the hydroelectric CRVA?
- b) Please provide an explanation of why deferral is required to provide the necessary details to support recoverability.
- c) Assuming the balance is cleared in OPG’s next DVA proceeding, please provide an estimate of the incremental interest costs on the deferred balance.

Response

- a) The December 31, 2024 and December 31, 2025 balances of the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA") are amounts recoverable of \$162.1M and \$218.9M, respectively, as shown in Ex. H1-1-1, Table 1, line 6, col. (c) and Ex. L-H1-Staff-260, Attachment 1, Table 1, line 6, col. (d).
- b) Refer to Ex. L-H1-Staff-260, part b).
- c) The Applicants have not yet decided on the timing of any next deferral and variance account clearance application and are therefore unable to perform the analysis requested. Refer to Ex. L-H1-Staff-255, part a) iv) for a hypothetical estimate of the interest on the balance of the hydroelectric components of the CRVA as at December 31, 2031.

SEC Interrogatory #209

Interrogatory

**Reference:
H1-1-1, p. 30**

Question(s):

With respect to the Gross Revenue Charge Variance Account ("GRC"):

- a) Is OPG aware of any discussions within the Government regarding changes to the GRC? If so, please provide details.
- b) Would changes in the GRC rate be covered by the existing Income and Other Taxes Variance Account?

Response

- a) No.
- b) No, the scope of the Income and Other Taxes Variance Account, as set out in Ex. H1-1-1, Section 5.5, does not cover any changes in the GRC rate.

For clarity, the eligible property tax changes covered by the Income and Other Taxes Variance Account include payments in lieu of property tax to the Ontario Electricity Financial Corporation and municipal property taxes, but not the property tax component (or water rental component) of the GRC.

SEC Interrogatory #210

Interrogatory

Reference:
H1-1-1, p. 39

Question(s):

With respect to the Nuclear Development Variance Account, OPG proposes that it would defer clearance of the balance related to costs for new nuclear generation facilities other than the DNNP.

- a) What is the total amount of the deferred balance broken down by capital and non-capital?
- b) Assuming the balance is cleared in OPG's next DVA proceeding, please provide an estimate of the incremental interest costs on the deferred balance.

Response

- a) The entirety of the December 31, 2024 balance of the non-DNNP components of the Nuclear Development Variance Account is for non-capital costs.
- a) The Applicants have not yet decided on the timing of any next deferral and variance account clearance application and are therefore unable to perform the analysis requested. Refer to Ex. L-H1-Staff-255, part a) iv) for a hypothetical estimate of the interest on the balance of the non-DNNP components of the Nuclear Development Variance Account as at December 31, 2031.

SEC Interrogatory #211

Interrogatory

Reference:
H1-1-1, p. 49

Question(s):

With respect to the Clarington Corporate Campus Deferral Account:

- a) Please provide a breakdown of the \$7M of costs included in the Account.
- b) Please explain why it is reasonable for customers to pay \$7M related to a project that did not proceed and was written-off.

Response

- a) The breakdown of the nuclear allocated costs for the Clarington Corporate Campus project recorded in the Clarington Corporate Campus Deferral Account as at December 31, 2024 is shown in Chart 1. This represents a portion of the \$11.1M total allocated to Nuclear is \$7.0M.

**Chart 1 – Clarington Corporate Campus Project Costs
Allocated to Nuclear by Category¹**

Cost Category	Costs (\$M)
Project management	1.6
Engineering	5.1
Interest	0.25
Total	7.0

¹ Numbers may not add due to rounding

- b) The costs for the Clarington Corporate Campus project were incurred in order to progress the project in accordance with OPG project governance. These project activities delivered defined deliverables, although they did not result in the construction of the asset.

During the project planning phase, value engineering analysis and design adjustments were required to ensure the project encompassed cost escalation and inflationary pressures resulting from the then on-going global pandemic and supply

1 chain constraints. An assessment of these impacts on the project costs and project
2 viability led to the decision to cancel the Clarington Corporate Campus project and
3 proceed with a new preferred alternative to purchase and renovate 1908 Colonel
4 Sam Drive (OPG's Corporate Headquarters). This decision was based on
5 information gained from Clarington Corporate Campus project activities and further
6 informed the economic analysis of the options. Additionally, lessons learned from
7 the project were incorporated into the planning of the Corporate Headquarters
8 (such as longer procurement lead times).

9
10 The work undertaken advanced the understanding of the project's technical
11 feasibility, the identification of risks, and enabled cost avoidance had the project
12 not been re-assessed after the planning phase. The costs included in the Clarington
13 Corporate Campus Deferral Account reflect only those costs for work completed
14 and that were necessary during the planning phase, and should be recovered.

SEC Interrogatory #212

Interrogatory

Reference:
H1-1-1, p. 50

Question(s):

With respect to the Earnings Sharing Deferral Account, based on OPG's 2026 budgeted production forecast, included in this application, please provide an estimate of the year-end 2026 balance for the account. Please provide all supporting calculations.

Response

Based on OPG's 2026 forecast information included in this Application, including the 2026 budgeted production forecast, and the 2025 preliminary actual results as provided in Ex. L-I1-Staff-266, Attachment 2, the estimated year-end 2026 balance for the forecast Earnings Sharing Deferral Account is nil. Refer to Chart 1 below for the supporting calculations.

Chart 1 - OPG's Regulated Earnings Above Deadband and ESM Deferral Account Entry for 2022-2026 (\$M)

Line No.	Description	Actual 2022	Actual 2023	Actual 2024	Preliminary Actual 2025	Forecast 2026	Forecast Cumulative
		(a)	(b)	(c)	(d)	(e)	(a+b+c+d+e)
1	Actual Nuclear Regulated Earnings ¹	477.1	726.8	46.0	878.6	214.5	
2	Actual Hydroelectric Regulated Earnings ¹	430.0	355.1	459.1	355.6	375.3	
3	Total Actual Regulated Earnings (line 1 + line 2)	907.0	1,082.0	505.1	1,234.1	589.8	
4	Actual Nuclear Rate Base Financed by Capital Structure ²	8,506.0	9,551.2	11,039.0	12,783.3	14,653.6	
5	Actual Regulated Hydroelectric Rate Base Financed by Capital Structure ²	7,734.7	7,990.0	8,124.4	8,283.7	8,610.5	
6	Actual Total Rate Base Financed by Capital Structure (line 4 + line 5)	16,240.8	17,541.2	19,163.4	21,067.0	23,264.1	
7	OEB-Approved Equity %	45%	45%	45%	45%	45%	
8	OEB-Approved ROE Rate for Earnings Sharing % ³	8.98%	8.97%	8.94%	8.92%	8.91%	
9	Deadband ROE Rate % (line 8 + 100bps)	9.98%	9.97%	9.94%	9.92%	9.91%	
10	Deadband Regulated Earnings (line 6 x line 7 x line 9)	729.3	786.6	857.5	940.8	1,037.3	
11	Regulated Earnings (Deficiency) Variance to Deadband (line 3 - line 10)	177.7	295.3	(352.5)	293.4	(447.4)	(33.4)
12	Estimated Provision for Income Tax (line 11 x 25%/(1-25%))						(11.1)
13	Gross Earnings (Deficiency) Variance to Deadband (line 11 + line 12)						(44.6)
14	Deferral Account Entry (line 13 X 50%, if line 11 > 0)						0.0

¹ 2022-2024 per Table 2, line 13 of revised annual regulatory return filed on March 10, 2026 for these years. Preliminary actual 2025 per Ex. L-I1-Staff-266, Attachment 1, Table 2, line 13. Forecast 2026 per Ex. I1-1-1, Table 5, line. 23, col. (c) .

² 2022-2024 per Table 2a, line 4a of revised annual regulatory return filed on March 10, 2026 for these years. Preliminary 2025 per Ex. L-I1-Staff-266, Attachment 1, Table 2a, line 4a. Forecast 2026 per Ex. L-I1-Staff-266, Attachment 2, Table 2a, line 4a.

³ OEB-Approved ROE Rate % weighted by actual rate base financed by capital structure for 2022-2025, and the equivalent budget rate base for 2026. See Chart 2 below.

Chart 2 - OPG's OEB-Approved Return on Equity for 2022-2026 (\$M)

		OEB Approved Return on Equity		Actual and Budgeted Rate Base Financed by Capital Structure ³		$\frac{(b) \cdot (d)}{((d) + (e)) + (c) \cdot (e) / ((d) + (e))}$
Line No.	Year	Regulated Hydroelectric ¹	Nuclear ²	Regulated Hydroelectric	Nuclear	OEB Approved Return on Equity Rate for Earnings Sharing
	(a)	(b)	(c)	(d)	(e)	(f)
1	2022	9.33%	8.66%	7,735	8,506	8.98%
2	2023	9.33%	8.66%	7,990	9,551	8.97%
3	2024	9.33%	8.66%	8,124	11,039	8.94%
4	2025	9.33%	8.66%	8,284	12,783	8.92%
5	2026	9.33%	8.66%	8,611	14,654	8.91%

¹ Col. (b) calculated as the average of 2014 and 2015 OEB-approved return on equity for regulated hydroelectric facilities, per EB-2013-0321 Payment Amounts Order, Appendix A, Table 5b, col. (c), line 5 and Table 6b, col. (c), line 5, respectively.

² Col. (c) from EB-2020-0290 Payment Amounts Order, Appendix A, Tables 11-15, cols. (c) lines 5a.

³ 2022-2024 per Table 2a, Note 5, line 4a of revised annual regulatory return filed on March 10, 2026 for these years. Preliminary actual 2025 per Ex. L-I1-Staff-266, Attachment 1, Table 2a, Note 5, line 4a. Forecast 2026 per Ex. L-I1-Staff-266, Attachment 2, Table 2a, Note 5, line 4a.

SEC Interrogatory #213

Interrogatory

Reference:
H1-1-1, p. 52

Question(s):

With respect to the Pickering B Variance Account:

- a) Please provide all supporting calculations regarding the \$131.1M balance as of December 31, 2024.
- b) Please provide the balance of the account as of December 31, 2025.
- c) Based on the 2026 budgeted production forecast, included in this application, please provide the estimated balance of the account at the end of December 31, 2026. Please provide all supporting calculations.

Response

a) For the reasons outlined in Ex. L-H1-Staff-260, part b), OPG has not proposed to clear the balance in this account in this Application and, as such, declines to provide the requested supporting calculation on the basis of relevance.

b) The balance of the account as of December 31, 2025 is an amount recoverable of \$349.1M, as shown in Ex. L-H1-Staff-260, Attachment 1, Table 1c, line 46, col. (g).

The projected balance in the account as of December 31, 2026 is an amount refundable of \$119.8M, as shown at Ex. L-H1-Staff-260, Attachment 2, Table 1, line 46, col. (e). OPG declines to provide the supporting calculations for the reasons noted in part a) above.

SEC Interrogatory #214

Interrogatory

Reference:

H1-1-1, p. 60, 71

Question(s):

With respect to the proposed Change of Laws Deferral Account:

- a) OPG states that the account “would record material impacts to regulated hydroelectric and nuclear costs and revenues over the IR term resulting from changes in legal and regulatory requirements”. Please define “material impacts” for both OPG and DNNP.
- b) If this account was in place during EB-2020-0290, please provide a full list of all changes in laws that would be eligible for recording in the account, an estimate of the specific amount, and if it would have met OPG’s definition of material impact.

Response

- a) Refer to Ex. L-H1-CCC-106.
- b) As discussed in Ex. H1-1-1, Section 7.1.1, if the Change of Laws Deferral Account (OPG) was established in EB-2020-0290, it would have captured the overturning of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* (“Bill 124”). In response to this change in law, OPG filed for an accounting order application with the OEB (EB-2023-0098) requesting establishment of a variance account to record the nuclear revenue requirement impacts resulting from Bill 124 being overturned, then estimated at \$188M¹ over the 2022-2026 IR term.

While OPG is not aware of any other change of laws during the 2021-2025 period that would have met the definition of a material impact, the Applicants continue to believe that changes in legal requirement are outside of their control and are not reasonably foreseeable to them. In Ex. H1-1-1, the Applicants have provided examples of laws OPG is currently monitoring that may have a material impact during the IR term, but the Applicants are ultimately unable to predict whether these laws and regulation changes will materialize, or whether any other new change in legal requirements may be proposed during the IR term that would have a material

¹ EB-2023-0098 Decision and Order, June 27, 2023, p. 8.

1 impact on the Applicants. The Applicants believe that the making of the request for
2 the account during this proceeding, prior to any settlement or decision, is consistent
3 with the OEB's decision in EB-2023-0098, that where OPG identified a known
4 variable, "OPG should have taken into consideration and governed themselves
5 accordingly, for example by identifying the issue and also by seeking a specific
6 variance account as part of their application."²

² Decision and Order, EB-2023-0098, Ontario Energy Board, June 27, 2023, p. 6.

Board Staff Interrogatory #055

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / p. 2

Preamble:

At Reference 1, OPG states that the nuclear payment amount rider set through this proceeding shall be calculated as $(E + F) / (C + D)$, where “E” is the sum of the balances proposed for clearance in deferral and variance accounts for OPG’s regulated balances proposed for clearance in deferral and variance accounts for OPG’s regulated nuclear facilities, “F” is the sum of the balances proposed for clearance in deferral and variance accounts for the Darlington New Nuclear Program (DNNP) facilities, and “C” and “D” are the OEB-approved production forecasts for OPG’s regulated nuclear facilities and the DNNP facilities, respectively.

Question(s):

- a) Please confirm and quantify whether concurrent cost recovery (CCR) amounts are included in, as applicable:
 - i. “E”, the regulated nuclear facilities, or
 - ii. “F”, the DNNP facilities
- b) Please provide a scheduled isolating the CCR’s impact on the nuclear payment amount rider (\$/MWh) for each year 2027-2031.
- c) Please provide a bill impact analysis isolating CCR from all other nuclear revenue requirement drivers.
- d) Please confirm whether CCR recovery is grossed-up for income taxes within the revenue requirement. If CCR interest is not grossed-up directly, please explain how the associated income tax effects are reflected in the determination of the payment amounts.

Response

a) and b)

There are no CCR amounts included in “E” or “F” as part of the proposed payment riders in this proceeding. In accordance with O. Reg. 53/05, CCR amounts are included, on a forecast basis, in OPG and DNNP LP’s nuclear revenue requirements and resulting blended nuclear payment amounts proposed in this proceeding.

For clarity, as stated at Ex. H1-2-1, p. 2, footnote 3, “[the] amount in “F” is equal to zero as the Application is not proposing clearance of any deferral and variance accounts for the DNNP facilities.” The amount in “E” is per Ex. H1-2-1, Table 2, line 32 and represents the sum of the balances proposed for clearance in the deferral and variance accounts for OPG’s nuclear facilities as of year-end 2024. There are no CCR amounts included in those balances.

c) The requested bill impact analysis isolating the CCR amounts sought in this Application is included in Chart 1 below. This analysis reflects the format, methodology and applicable inputs used to produce Ex. I1-1-2, Table 1 that determines the estimated typical residential consumer impacts of the Application, but only considering the requested CCR amounts.

Chart 1 - Annualized Residential Consumer Impact of CCR Amounts

	2027	2028	2029	2030	2031	Avg
Typical Consumption (kWh/month)	787	787	787	787	787	787
Typical Usage of OPG and DNNP LP Generation (kWh/month)	246	284	276	287	304	280
Typical Bill (\$/month)	142.10	142.10	142.10	142.10	142.10	142.10
Typical Bill Impact (\$/month)	2.46	0.83	1.18	0.38	(2.41)	0.49
Typical Bill Impact (%)	1.7%	0.6%	0.8%	0.3%	(1.7%)	0.3%
Prior Year Weighted Avg (\$/MWh)	0.00	10.02	12.93	17.19	18.50	
Current Year Weighted Avg (\$/MWh)	10.02	12.93	17.19	18.50	10.59	
Change in Weighted Avg (\$/MWh)	10.02	2.91	4.26	1.31	(7.91)	
Total Regulated Production (TWh)	51.2	59.2	57.5	59.8	63.3	
Forecast 2027 Provincial Demand (TWh)	163.9	163.9	163.9	163.9	163.9	
Proportion of Customer Usage	31.2%	36.1%	35.1%	36.5%	38.6%	

d) The recovery of the CCR amounts is not “grossed-up” for income taxes within OPG and DNNP LP’s proposed revenue requirements. As interest costs are generally tax deductible, OPG’s regulatory income tax calculations at Ex. F4-2-1, Tables 3d and 3g do not treat CCR as requiring an adjustment to regulatory earnings before tax. This results in no income tax effect being included in the proposed regulatory income taxes in respect of the CCR amounts.

Board Staff Interrogatory #139

Interrogatory

Reference:

Exhibit E1 / Tab 1 / Schedule 1 Table 2

Ref 2: Exhibit H1 / Tab 1 / Schedule 1 Table 5

Ref 3: EB-2023-0336 Exhibit H1 / Tab 1 / Schedule 1 Table 5

Ref 4: EB-2020-0290 Exhibit H1 / Tab 1 / Schedule 1 Table 5

Ref 5: EB-2018-0243 Exhibit H1 / Tab 1 / Schedule 1 Table 5

Ref 6: Exhibit I1 / Tab 1 / Schedule 1 / Attachment 1

Ref 7: Exhibit E1 / Tab 1 / Schedule 2 / pp. 1-2

Preamble:

Reference 1 shows the 2027 planned hydroelectric production as 32.5 TWh.

From References 2 to 5, OEB staff has summarized the historical Surplus Baseload Generation (SBG) amount, Net of SBG production amount, and Pre-spill amount from OPG's Hydroelectric Surplus Baseload Generation Variance Account in Table 1 - Surplus Baseload Generation Variance Account Summary.

Reference 7 provides the narrative for period -over-period changes for the Test Year.

Table 1 – Surplus Baseload Generation Variance Account Summary (TWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
SBG	4.3	5.2	3.2	3.3	4.3	1.9	1.6	1	0.3
Actual Production After Spill	29.5	30.7	29.8	30.5	30.3	29	31.1	31.4	32.5
Pre-spill Production	33.8	35.9	33.0	33.8	34.6	30.9	32.7	32.4	32.8
Pre-spill Production Average 2016-2024									33.3

OEB staff substituted the Pre-spill Production Average for 2016-2024 of 33.3 TWh into the revenue deficiency calculation at Reference 6. As shown in Table 2 - Summary of Revenue Deficiency – Regulated Hydroelectric, the Indicated Production Revenue using the Historical Pre-spill Production Average would be \$1,461.2 million, which is \$36.8 million more than the OPG calculated amount of \$1,424.4 million.

Table 2 – Summary of Revenue Deficiency – Regulated Hydroelectric

Description	2027	2027 Using Pre-spill Average
Forecast Production (TWh)	32.5	33.3
2026 Payment Amount per EB-2020-0290 (\$/MWh)	43.88	43.88
Indicated Production Revenue (\$ millions) (line 1 x line 2)	1,424.4	1,461.2
Difference in Indicated production Revenue (\$ millions)		36.8
Revenue Requirement (\$ millions)	1,668.3	1,668.3
Revenue Requirement Deficiency (\$ millions) (line 4 - line 3)	243.9	207.1
Difference in Revenue Requirement Deficiency (\$ millions)		-36.8

Question(s):

- a) Please confirm the values presented in Table 1: Surplus Baseload Generation Variance Account Summary and Table 2: Summary of Revenue Deficiency – Regulated Hydroelectric. If not confirmed, please provide correct values and explain any differences between the OPG's 2027 production forecast and the historical average.
- b) Please provide the 2025 actual production and 2025 actual surplus baseload curtailed generation by Region.
- c) The Test Year comparison in the period over period analysis at Reference 7 compares 2027 to 2026. Please provide an explanation for the comparison of the 2027 Test Year forecast to the 2016 to 2025 average from part b).

Response

- a) OPG can confirm the production values referenced in Table 1 as historical actual production and foregone production due to SBG. With respect to Table 2, OPG can confirm the forecast production and 2026 payment amount, and the mathematical accuracy of the calculation. However, for the reasons outlined below, OPG does not agree that Table 2 is an appropriate calculation of the revenue deficiency.

The proposed production for setting the 2027 hydroelectric payment amount, presented in Ex. E1-1-1, is the appropriate value to use in calculating the revenue

1 deficiency. This is because both the budgeted production and the revenue
2 requirement for the 2027 test year should be based on a consistent set of forecast
3 data, the proposals for which are set out in the Application, and because OPG's
4 actual revenue will be based on its actual production, of which the forecast in this
5 Application represents OPG's expectations on a pre-SBG spill basis. Substituting
6 historical production averages into the revenue deficiency calculation is therefore
7 inconsistent with the rate-setting approach and produces an unrepresentative
8 result.

9
10 Refer to Ex. E1-1-2, Section 4 for a discussion of historical production trends, and
11 Ex. L-E1-Staff-138 for additional information regarding the historical period's
12 applicability to the 2027 production forecast.

- 13
14 b) OPG has provided 2025 actual production in an updated version of Ex. E1-1-1,
15 Table 1 in Ex. L-A1-CCC-001, Attachment 1, Table 27. Actual 2025 foregone
16 production due to SBG by region is shown in Chart 1 below.

17
18 **Chart 1 – 2025 Foregone Production Due to SBG**

	2025 Foregone Production Due to SBG (TWh) ^{1,2}
Niagara region	0.44
Eastern region	0.23
Western region	0.08
Total	0.75

19 ¹Numbers may not add due to rounding.

20 ²After May 1, 2025, SBG comprises both local and global SBG.

- 21
22
23 c) The 2027 forecast production value is provided utilizing long-term average water
24 conditions and specific forecast unit availability profiles which are a result of the
25 work programs planned to occur in 2027.

26
27 Actual and Foregone Production due to SBG occur based on prevailing water
28 conditions, unit availability, market conditions and other operational parameters.
29 Variability in actual water conditions is a key driver for the fluctuation in historical
30 pre-spill production amounts as are variations in actual unit availability driven by
31 historical work programs. Refer to Ex. L-E1-Staff-138 for additional discussion
32 regarding the applicability of the historical period to the 2027 test year production
33 forecast with respect to water availability and Ex. L-E1-CCC-063, Chart 1 for
34 foregone production due to planned outages over the historical period.

Board Staff Interrogatory #246

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 4-5

Ref 2: Exhibit I1 / Tab 1 / Schedule 1

Preamble:

Pursuant to amendment to O. Reg 53/05, OPG will recover interest on the Pickering Refurbishment Project (PRP) capital costs through concurrent cost recovery (CCR) during construction, and a separate PRP CCR variance account is established to true up forecast and actual CCR amounts. Prior to the CCR mechanism, financing costs flowed through capitalized interest.

OPG includes a forecast of CCR calculations for PRP totaling \$2,923.3 million over the 2027-2031 period.

Question(s):

- a) Please confirm whether CCR amounts for Pickering Refurbishment are excluded from Capacity Refurbishment Variance Account (CRVA) entries.
- b) Please confirm that interest impacts historically recorded in the CRVA are not recovered again via CCR, and that CCR amounts are not subsequently included in CRVA balances.

Response

- a) Confirmed. The CCR amounts for PRP are included in the nuclear revenue requirement on a forecast basis, as determined in Ex. I1-1-1, Table 7, and presented in Ex. I1-1-1, Table 2, line 22a. To the extent there is a difference between actual and forecast cumulative capital costs incurred by OPG in respect of the PRP, the impact of such a difference on CCR amounts will be recorded in the Pickering B Refurbishment Project Variance Account, consistent with the requirements of O. Reg. 53/05, section 5.8, and as described in Ex. H1-1-1, Section 5.30.

1 b) The Applicants assume that “interest impacts historically recorded in the CRVA” is
2 referring to the capitalization of interest to project costs eligible for the CRVA. The
3 Applicants confirm that PRP capital costs do not include capitalization of interest
4 effective January 1, 2026, as stated at Ex. I1-1-3, p. 7 and Ex. D2-3-8, p. 9. This
5 treatment ensures CCR amounts cannot be subsequently included in CRVA
6 balances.

7
8 The Applicants similarly confirm that that there is no duplication between any
9 amounts recorded in the CRVA prior to January 1, 2026 and the CCR amounts
10 effective January 1, 2026.

Board Staff Interrogatory #247

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 4-6

Ref 2: Exhibit I1 / Tab 1/ Schedule 1 / Table 6

Preamble:

O. Reg 53/05 section 12(1) provides that concurrent cost recovery (CCR) for the Darlington New Nuclear Program (DNNP) will be the actual cumulative capital incurred by the DNNP generator in respect of the Darlington New Nuclear Project multiplied by Ontario Power Generation Inc.'s long-term debt rate.

OPG lists the DNNP variance accounts effective January 1, 2026 including: the Development Variance Account, Capital Cost Amounts Variance Account, and the Generator Capital Structure Variance Account. The DNNP Generator Capital Structure Variance Account records the differences between forecast and actual financing parameters.

Reference 2 includes the forecast CCR amounts for DNNP totaling \$1,119.7 million from 2027-2031.

Question(s):

- a) Please confirm whether, following the introduction of CCR effective January 1, 2026, no interest is capitalized on construction work-in-progress (CWIP) for DNNP assets.
- b) Please explain how differences in financing parameters associated with the DNNP capital structure during construction are allocated between the CCR mechanism and the DNNP Generator Capital Structure Variance Account.
- c) Please confirm that financing cost variances recorded in the DNNP variance accounts do not overlap with CCR recovery.

- 1 d) Please provide a sensitivity analysis showing the impact of a +/-100 basis point
2 change in debt costs on:
3 i. DNNP capital structure variance account balances
4 ii. Nuclear payment amounts
5
6

7 **Response**
8

- 9 a) The Applicants confirm that no interest is capitalized on construction work-in-
10 progress for the DNNP following the effective date of January 1, 2026 for the CCR
11 mechanism for the DNNP.
12
13 b) The Applicants interpret the question as referring to DNNP LP's capital structure.
14 The financing parameters associated with the DNNP LP's capital structure do not
15 impact the CCR mechanism and therefore any differences therein are not allocated
16 between the CCR mechanism and the DNNP Generator Capital Structure Variance
17 Account.
18

19 Specifically, O. Reg. 53/05, sections 12(1) and 14(2)5 prescribe that CCR amounts
20 for the DNNP are to be determined by multiplying the cumulative capital costs
21 incurred for the DNNP by Ontario Power Generation Inc.'s long-term debt rate,
22 where long-term debt rate is defined as "the long-term debt rate reflecting the
23 generator's cost of long-term borrowing that is determined or approved by the
24 Board" in section 0.1(1) of O. Reg. 53/05. The CCR amounts are therefore
25 independent of the capital structure of DNNP LP and do not interact with and are
26 not eligible for the DNNP Generator Capital Structure Variance Account established
27 by O. Reg. 53/05, section 13(1).
28

29 The capital structure that is the subject of the DNNP Generator Capital Structure
30 Variance Account is necessarily with respect to DNNP LP's rate base (i.e., once
31 DNNP assets start being placed in service), as that is when the revenue
32 requirement will begin to reflect the impacts of a capital structure. On the other
33 hand, pursuant to O. Reg. 53/05, section 12(1) and 14(2)5, the CCR mechanism
34 applies to capital costs incurred for the DNNP facilities prior to such assets being
35 placed in service (i.e., construction work-in-progress). Refer to Ex. L-C1-Staff-039
36 for further discussion on the DNNP Generator Capital Structure Variance Account.
37

- 38 c) The Applicants confirm that there will be no overlap between the CCR amounts for
39 the DNNP, including such amounts recovered through the Darlington New Nuclear
40 Project Variance Account re Capital Cost Amounts, and any other financing cost
41 variances that may be recorded in another deferral or variance account for DNNP
42 LP.

- d)
- i. As set out in Ex. A1-4-4, Attachment 1, p. 7, the Applicants do not expect DNNP LP to obtain debt financing prior to December 31, 2031 and, as discussed in Ex. C1-1-1, Section 2.2, have proposed a 100% equity funded capital structure for DNNP LP during the 2027-2031 IR term. As such, there is no reference point relative to which to conduct the requested sensitivity analysis on debt costs, and no such analysis can be provided. For clarity, under the proposed capital structure for DNNP LP in this proceeding, any amount of debt actually raised by DNNP LP during the 2027-2031 IR term would reduce the equity component of the capital structure and be expected to result in a credit entry in the DNNP Generator Capital Structure Variance Account.
 - ii. To perform the requested analysis, the Applicants adjusted the cost of OPG's forecast new debt issues in Ex. C1-1-1, Tables 1-5 by +/- 100 basis points and additionally flowed through the resulting cost of debt rates to both DNNP and PRP CCR amounts as well as applicable asset service fee calculations, holding all other variables constant. The results on nuclear payments amounts are summarized in Chart 1 below.

Chart 1 – Nuclear Payment Amounts Sensitivity to Cost of OPG's New Debt Issues (\$/MWh)

	2027	2028	2029	2030	2031
Pre-filed (Ex. I1-3-1)	206.70	192.42	202.74	199.16	219.60
+ 100 basis points	216.67	201.30	213.87	210.24	227.59
- 100 basis points	196.74	183.55	191.61	188.08	211.60

Board Staff Interrogatory #248

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

OPG states that the Income and Other Taxes Variance Account (OPG) does not record nuclear Scientific Research and Experimental Development investment tax credits (SR&ED ITC) impacts (and related taxes) effective June 1, 2017; those are instead recorded in the SR&ED ITC Variance Account. OPG also states that additions to the Income and Other Taxes Variance Account will be calculated without duplication with other impacted accounts such as the Capital Related Variance Account (CRVA).

Question(s):

- a) Please provide a mapping of all tax-related differences that may be recorded in:
- i. The Income and Other Taxes Variance Account (OPG)
 - ii. The SR&ED ITC Variance Account (OPG)
 - iii. The CRVA
 - iv. Any proposed clean electricity or change-of-laws accounts, and explain, with examples, how OPG ensures there is no overlap or double recording among these accounts.

Response

- a) The Applicants understand that the question intends to refer to the Capacity Refurbishment Variance Account ("CRVA") as no Capital Related Variance Account is in place or proposed by the Applicants. The Applicants understand the question to relate to income (or capital) taxes or payments in lieu of income (or capital) taxes.

A mapping of tax-related differences (including differences in the Clean Electricity Investment Tax Credits ("CEITCs")) that may be recorded in the referenced accounts for OPG and similar accounts proposed for DNNP LP is provided below, as well as an explanation of how the account methodologies will ensure no duplication occurs between the applicable accounts in respect of these impacts. For completeness, the discussion also covers the proposed Global Hydroelectric Capital Variance Account ("GHCVA"), the Nuclear Development Variance Account ("NDVA"), the Darlington New Nuclear Project Variance Account re Development

1 (“DNNPVARD”) and the proposed Impact of Change in Tax Status Variance
2 Account (DNNP).

3
4 Global Hydroelectric Capital Variance Account

5 As discussed at Ex. A1-3-2, Section 2.3.5, the Application proposes to establish the
6 GHCVA to record the difference in revenue requirement attributed to actual total
7 regulated hydroelectric capital in-service amounts and the forecast capital related
8 revenue requirement (“CRRR”) amounts underpinning the proposed custom capital
9 factor (“C-factor”) as part of the hydroelectric price-cap index custom incentive rate-
10 setting framework. Such CRRR includes the associated income tax impacts. With
11 respect to the interaction with the Income and Other Taxes Variance Account (OPG)
12 and the proposed Clean Electricity ITC Variance Account (OPG), the evidence at
13 Ex. A1-3-2, pp. 25-26 explains that entries into each of these accounts would be
14 recorded independently of the GHCVA and, where applicable, a corresponding
15 normalization adjustment would be made to the revenue requirement of the actual
16 regulated hydroelectric capital in-service amounts used for determining entries in
17 the GHCVA (and assessing their interaction with the entries in the CRVA) to the
18 extent the amounts recorded in these accounts also affect such revenue
19 requirement impact. The proposed mechanism for addressing the interaction of the
20 GHCVA and the CRVA, encompassing both tax and non-tax impacts, is discussed
21 at Ex. A1-3-2, p. 23, line 17 to p. 25, line 15 and Ex. Ex. L-H1-Staff-253.

22
23 Income and Other Taxes Variance Accounts

24 Ex. H1-1-1, Sections 5.5 and 8.4 outline the conditions that would give rise to
25 entries recorded in the Income and Other Taxes Variance Account (OPG) and
26 Income and Other Taxes Variance Account (DNNP). Broadly, these conditions
27 include changes in income (or capital) tax legislation, regulations, tax authority
28 policies, or income (or capital) tax reassessments such as from audits or application
29 of tax rules. These accounts would record the impacts of such changes for the
30 prescribed facilities to the extent not already reflected in the approved revenue
31 requirements or captured in another deferral or variance account (as also
32 discussed below). For clarity, as noted at Ex. H1-1-1, p. 15, lines 7-12 and Ex. H1-
33 1-1 p. 69, line 26 to p. 70, line 2, the accounts would not include the revenue
34 requirement impact of the CEITCs.

35
36 SR&ED ITC Variance Accounts

37 As discussed at Ex. H1-1-1, Section 5.20, the SR&ED ITC Variance Account (OPG)
38 presently records the difference between actual SR&ED ITCs for OPG’s nuclear
39 facilities as determined after any tax audits and the forecast SR&ED ITCs reflected
40 in the revenue requirement approved by the OEB, including income tax on the
41 difference. The Application proposes to extend the scope of this account to OPG’s
42 regulated hydroelectric facilities (as further discussed in Ex. L-H1-Staff-251) and to
43 establish an equivalent SR&ED ITC Variance Account (DNNP) for the DNNP
44

1 facilities, as of the effective date of the payment amounts order in this proceeding.
2 The above noted variances related to the SR&ED ITCs would be captured solely in
3 these SR&ED ITC Variance Accounts and not in any other deferral or variance
4 account (with the exception of any audit resolution adjustments for OPG's
5 regulated hydroelectric facilities in respect of periods prior to the effective date of
6 the account's applicability to these facilities, which would continue to be recorded
7 in the Income and Other Taxes Variance Account (OPG)).¹
8

9 Capacity Refurbishment Variance Account, Nuclear Development Variance
10 Account and the Darlington New Nuclear Project Variance Account re Development
11 The discussion below is provided with respect to the CRVA. It applies equally to the
12 NDVA and the DNNPVARD, which would record equivalent tax-related components
13 and have the equivalent operation with respect to the interaction of these
14 components with the other applicable accounts discussed in this response.
15

16 The CRVA records the revenue requirement impacts of variances in capital and
17 non-capital costs and firm financial commitments incurred to increase the output of,
18 refurbish or add operating capacity to an OPG prescribed generating facility. This
19 includes the income tax impacts of such variances, including differences in capital
20 cost allowance ("CCA") impacts and the tax "gross up" on the associated
21 depreciation expense and equity return component of the rate base. Where there
22 is a potential overlap between the CRVA and another tax-related deferral or
23 variance account (other than the SR&ED ITC Variance Account (OPG), as
24 discussed above), the impacts would be recorded in the CRVA.
25

26 For example, as noted at Ex. H1-1-1, p. 16, lines 9-13 and footnote 20, the impact
27 of new accelerated investment incentive property ("AIIP") rules that have resulted
28 in a first-year increase in CCA deductions is recorded, as part of a credit entry (or
29 a reduction to a debit entry), in the CRVA for the CRVA-eligible expenditures (to the
30 extent not reflected in the approved revenue requirements), rather than the Income
31 and Other Taxes Variance Account. Similarly, as noted at Ex. H1-1-1, p. 21, lines
32 14-16, the revenue requirement impact of the CEITCs received by OPG for CRVA-
33 eligible expenditures (to the extent not reflected in the approved revenue
34 requirements) would be recorded in the CRVA, rather than the proposed Clean
35 Electricity ITCs Variance Account (OPG).
36

37 Clean Electricity ITC Variance Accounts

38 The proposed Clean Electricity ITC Variance Account (OPG) and Clean Electricity
39 ITC Variance Account (DNNP) would record the differences in revenue requirement
40 impact between the actual CEITCs received for OPG or DNNP LP's eligible
41 projects, respectively, relative to forecasts reflected in the approved revenue

¹ The SR&ED ITCs are not captured in the CRRR as part of the proposed custom price-cap index custom incentive rate-making framework for the regulated hydroelectric facilities and therefore are not subject to the GHCVA.

1 requirements, to the extent such impacts are not reflected in another deferral or
2 variance account, such as the CRVA or the NDVA for OPG or the DNNPVARD for
3 DNNP LP. As discussed elsewhere in this response, Income and Other Taxes
4 Variance Account (OPG), Income and Other Taxes Variance Account (DNNP) and
5 the Impact of Change in Tax Status Variance Account (DNNP) would not record the
6 revenue requirement impacts of the CEITCs.

7
8 For example, assuming the impact of the CEITCs is not reflected in the payment
9 amounts and OPG receives a CEITC that reduces the revenue requirement of a
10 capital project at a prescribed facility and such project is not eligible for the CRVA,
11 the revenue requirement impact would be captured as a part of a credit entry in the
12 Clean Electricity ITC Variance Account (OPG). Should the same occur with respect
13 to a capital project that is CRVA-eligible, the impact would be captured as part of a
14 credit entry (or a reduction to a debit entry) in the CRVA instead.²

15
16 Change of Laws Deferral Accounts

17 As further discussed in Ex. L-H1-Staff-259, the proposed Changes of Laws Deferral
18 Account (OPG) and Change of Laws Deferral Account (DNNP) would record
19 material cost (i.e., revenue requirement) and revenue impacts to OPG's nuclear
20 and regulated hydroelectric facilities, and the DNNP facilities, respectively, arising
21 from provincial and/or federal legislative or regulatory changes (collectively,
22 "change in law(s)"), to the extent these impacts are not recorded in other deferral
23 and variance accounts. As any such impacts related to income (or capital) taxes
24 would be recorded, as applicable, in the respective Income and Other Taxes
25 Variance Accounts or Clean Electricity ITC Variance Accounts, Impact of Change
26 in Tax Status Variance Account (DNNP) or another account, the Changes of Laws
27 Deferral Accounts would not record any impacts of changes in laws related to
28 income (or capital) taxes (including, for clarity, related to the CEITCs).

29
30 For clarity, the Changes of Laws Deferral Accounts would record, as part of a
31 revenue requirement impact of a change in laws not related to income (or capital)
32 taxes, the applicable income tax impact of such a change. For example, if new
33 compliance activities in connection with conserving the American Eel, discussed at
34 Ex. H1-1-1, p. 61-63, result in an eligible outlay of capital expenditures (that is not
35 also eligible for the CRVA), its revenue requirement impact recorded in the Change
36 of Laws Deferral Account (OPG) would include the income tax impacts related to
37 any additional CCA and the tax "gross up" on the associated depreciation expense
38 and equity return component of the rate base.

39

² The CEITCs for the Pickering Refurbishment Program and the DNNP will reduce the amount of Concurrent Cost Recovery interest amounts by virtue of reducing the associated capital costs (see Ex. I1-1-3), with such impacts therefore being subject to the Pickering B Refurbishment Project Variance Account and the Darlington New Nuclear Project Variance Account re Capital Cost Account, respectively, and not any other deferral or variance account.

1 Impact of Change in Tax Status Variance Account (DNNP)

2 As discussed at Ex. F4-2-1, p. 4, lines 6-21, given that DNNP LP is a limited
3 partnership, the associated regulatory income taxes have been calculated with
4 respect to the tax status of the partners in DNNP LP, such that these taxes reflect
5 the portion of the regulatory taxable income that is attributable to taxable partners
6 only. OPG is presently expected to be the only taxable partner in DNNP LP over
7 the IR term. The proposed Impact of Change in Tax Status Variance Account
8 (DNNP) would record the impact on the forecast regulatory income taxes reflected
9 in the approved revenue requirement of any changes to the tax status of DNNP
10 LP's partners, to the extent such impacts are not reflected in another deferral or
11 variance account, such as the DNNPVARD. For clarity, any such impacts in relation
12 to SR&ED ITCs would be recorded in the SR&ED ITC Variance Account (DNNP)
13 and in relation to the CEITCs, in the Clean Electricity ITC Variance Account (DNNP)
14 or another deferral or variance account such as the DNNPVARD, as applicable.
15

16 Where a change from a tax exempt to a taxable status of a partner occurs, the
17 impacts recorded in the Impact of Change in Tax Status Variance Account (DNNP)
18 would be calculated by applying the respective tax legislation to the relevant
19 components of the approved revenue requirement, while holding all other variables
20 constant in relation to the forecasts underpinning the approved revenue
21 requirement. Similarly, should a change from a taxable to a tax-exempt status of a
22 partner occur, such impacts would be calculated by removing the relevant effects
23 of the respective tax legislation from the approved revenue requirement. For clarity,
24 no impacts would be recorded in the Income and Other Taxes Variance Account
25 (DNNP) in connection with a change in the tax status of a partner, although impacts
26 related to subsequent tax reassessments in respect of a taxable partner would be
27 eligible for the Income and Other Taxes Variance Account (DNNP), to the extent not
28 captured in another deferral or variance account.
29

30 For example, should one of the partners of DNNP LP assumed to be tax-exempt
31 for purposes of setting payment amounts becomes taxable during the IR term, the
32 DNNPVARD would capture the income tax impacts under the respective tax
33 legislation associated with any capital and non-capital costs incurred and firm
34 financial commitments made for the DNNP that would be attributable to such
35 partner as well as the revenue requirement of any CEITCs for which the partner
36 would be eligible, the SR&ED ITC Variance Account (DNNP) would capture any
37 SR&ED ITCs, including taxes thereon, that would be attributable to such partner,
38 and the Impact of Change in Tax Status Variance Account (DNNP) would capture
39 the portion of income tax impacts attributable to the partner in respect of the
40 components of the approved revenue requirement not captured by the DNNPVARD
41 or the SR&ED ITC Variance Account (DNNP).

Board Staff Interrogatory #249

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / Table 1

Ref 2: Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

OPG is seeking clearance of audited December 31, 2024 deferral and variance account (DVA) balances, less approved amortization amounts for 2025 and 2026, together with the income tax impacts associated with the recovery of the Pension & Other Post-Employment Benefits (OPEB) Cash Versus Accrual Differential Deferral Account through payment amount riders.

In Table 1 of Reference 1, a separate hydroelectric line for post-2019 additions is shown for (\$10.2 million), amortized over 36 months, resulting in (\$3.4 million) per year.

At Reference 2, for the years 2027-2029, Regulatory Asset Amortization of the Pension and OPEB Cash vs. Accrual Differential Account of (\$10.2 million) is noted as an addition for regulatory tax purposes. OEB staff would generally expect that the addition of an asset to be represented as a positive line item.

Question(s):

- a) Please provide the detailed calculation of the (\$10.2) million balance, including the underlying Pension & OPEB DVA balance to which the taxes relate.
- b) Please reconcile the amount to the note 5 in Reference 1, where the balance is calculated as line 12 x tax rate / (1 – tax rate).
- c) Please identify the exact tax rate used from Reference 2 and explain why that rate is appropriate.
- d) Please reconcile the resulting (\$3.4 million) annual amortization amounts in Reference 1 to the tax model treatment in Reference 2.
- e) Regarding Reference 2, please explain the sign convention and tax treatment of the hydroelectric DVA, including:
 - i. Why the line is shown as a negative amount;
 - ii. Why it is treated as a subtraction in the derivation of regulatory taxable income/earnings before tax; and,

1 iii. How the treatment interacts with the separate tax recovery shown in Reference
2 1.

3
4
5 Response

6
7 a) and b)

8
9 Refer to Ex. H1-2-1, Table 1, Note 5 for the calculation of the (\$10.2M) income tax
10 impact referenced (i.e., $(\$30.5M) \times (25\% / (1-25\%))$) and to Ex. H1-1-1, Table 7 (sum
11 of line 13, cols. (a) and (d)) for the underlying balance of (\$30.5M) in the Pension
12 & OPEB Cash Versus Accrual Differential Deferral Account.

13
14 c) The income tax rate is 25%, as shown at Ex. F4-2-1, Table 3b, line 26, and is
15 appropriate because it reflects the overall income tax rate applicable to OPG's
16 electricity generation business. As noted in that exhibit, the income tax rate has
17 remained unchanged throughout the historical period, with no changes forecasted
18 over the bridge or IR term.

19
20 d) and e)

21
22 Exhibit F4-2-1, Table 3b, line 4 corresponds to the amortization of the Pension &
23 OPEB Cash Versus Accrual Differential Deferral Account at Ex. H1-2-1, Table 1,
24 line 12 and is shown as a negative amount, rather than a positive amount, as it
25 represents an amortization of a regulatory liability, rather than a regulatory asset.
26 In the course of responding to this interrogatory, OPG noted that this line has been
27 incorrectly labelled to refer to a "Regulatory Asset" and should instead refer to a
28 "Regulatory Liability". OPG will file a correction to the evidence.

29
30 Exhibit F4-2-1, Table 3b, line 4 is shown in the derivation of regulatory taxable
31 income for 2027-2029 for consistency with the principle, as articulated at Ex. F4-2-
32 1, p. 15, lines 1-5 and applied in OPG's previous payment amounts proceedings,
33 that to the extent, 1) there is no income tax benefit/cost to be matched to a variance
34 or deferral account recovery or refund (i.e., its amortization), and 2) where such
35 impact is not otherwise reflected in the account balance itself, there should be an
36 adjustment to regulatory earnings before tax in the period of such recovery or
37 refund. The Pension & OPEB Cash Versus Accrual Differential Deferral Account
38 meets both of these criteria and therefore a corresponding adjustment for its
39 amortization has been shown in the calculation of regulatory income taxes.
40 Typically, such an adjustment would give rise to a regulatory income tax impact
41 equal to the amount of the adjustment multiplied by $(\text{tax rate} / (1 - \text{tax rate}))$, or in
42 this case, $(\$10.2M) \times (25\%) / (1 - 25\%)$, being equal to (\$3.4M) at Ex. H1-2-1, Table
43 1, line 17.

1 Because the income tax impact of refunding the Pension & OPEB Cash Versus
2 Accrual Differential Deferral Account over the 2027-2029 period is included as part
3 of the proposed payment amount riders by virtue of Ex. H1-2-1, Table 1, line 17,
4 the calculation of regulatory income taxes for these years is further modified to
5 avoid duplication of this impact between the revenue requirement and the payment
6 amount riders. This is accomplished by adjusting the derivation of regulatory
7 earnings before tax at Ex. F4-2-1, Table 3c, lines 3a and 18a.¹ The net effect of
8 these adjustments, taken together with Ex. F4-2-1, Table 3b, line 4, is that the
9 regulatory income tax expense at Ex. F4-2-1, Table 3b, line 23 does not reflect any
10 income tax impact related to the refund of the Pension & OPEB Cash Versus
11 Accrual Differential Deferral Account balance. In other words, there would be no
12 impact to the amounts calculated at Ex. F4-2-1, Table 3b, line 23 if all of the
13 following lines in Ex. F4-2-1 were zeroed out: Table 3b, line 4; Table 3c, line 3a and
14 Table 3c, line 18a.

¹ This presentation approach is consistent with EB-2020-0290, Ex. F4-2-1: Table 3a, line 7 and Table 3c, lines 5a and 21a; EB-2020-0290 Payment Amounts Order: Tables 17-21, line 7 and Tables 17a-21a, lines 5a and 21a.

Board Staff Interrogatory #250

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / Table 2

Ref 2: Exhibit F4 / Tab 2 / Schedule 1 / Table 3d

Preamble:

In Reference 1, the table shows Income and Other Taxes Variance – Nuclear with a 2024-year end balance of (\$9.5 million), with (\$7.3 million) already approved for 2025-2026 amortization, and (\$2.1 million) proposed for disposition in this application over 36 months or (\$0.7 million) per year.

Question(s):

- a) Please provide a continuity from the 2024 audited balance of (\$9.5 million) to the (\$2.1 million) proposed for disposition in this application.
- b) Please identify the components of the (\$7.3 million) already addressed through the 2025-2026 amortization, including the specific prior proceeding references.
- c) Please reconcile the annual (\$0.7 million) amounts to the tax model in Reference 2, if reflected there.
- d) Please confirm whether any part of the nuclear balance relates to items that would now instead be recorded in the Scientific Research and Experimental Development investment tax credits (SR&ED ITC) Variance Account or other dedicated tax accounts.

Response

- a) The requested continuity is found at Ex. H1-2-1, Table 2, line 11, cols. (a) to (d).
- b) The (\$7.3M) referenced is the sum of, and is therefore fully addressed, by the OEB-approved amortization for 2025 of (\$3.7M) and for 2026 of (\$3.7M) from Decision and Order, EB-2023-0336, June 13, 2024, Appendix A, Table 2, line 10, cols. (h) and (i), respectively.

- 1 c) Refer to Ex. F4-2-1, Table 3d, line 8, cols. (a) to (c), where the annual amounts for
2 2027 to 2029 are equal to the corresponding annual amortization amounts of
3 (\$0.7M) found at Ex. H1-2-1, Table 2, line 11.¹
4
- 5 d) Of the (\$2.1M) balance in the Income and Other Taxes Variance Account (OPG)
6 for OPG's nuclear facilities proposed for disposition in this Application, (\$1.0M)
7 relates to the increase in the recognition of the actual SR&ED ITCs for 2017, based
8 on the resolution of that year's income tax audit in 2023, which impact was pro-
9 rated for the period prior to June 1, 2017 for the purposes of recording in the
10 account. June 1, 2017 represents the effective date of the SR&ED ITC Variance
11 Account (OPG), which captures variances in SR&ED ITCs for OPG's nuclear
12 facilities beginning as of that date. The calculation of the above entry can be found
13 at Ex. H1-1-1, Table 6, lines 6-8, col. (b).

¹ The underlying balance of the Income and Other Taxes Variance Account (OPG) and therefore the associated annual amortization amounts of (\$0.7M) do not contain income tax impacts of the type described in Ex. L-F4-Staff-220, part b) iv).

Board Staff Interrogatory #251

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Ref 2: Exhibit H1 / Tab 2 / Schedule 1 / Table 2

Ref 3: Exhibit F4 / Tab 2 / Schedule 1

Preamble:

OPG states that the Scientific Research and Experimental Development investment tax credits (SR&ED ITC) Variance Account (OPG) records the difference between actual SR&ED ITCs for OPG's nuclear facilities, as determined after tax audits, and the forecast SR&ED ITCs reflected in approved revenue requirement, including the tax on the difference.

OPG proposes to extend the SR&ED ITC Variance Account (OPG) to include hydroelectric facilities as of the effective date of the payment amounts order. Historically, the hydroelectric treatment remained in the Income and Other Taxes Variance Account as noted in Reference 3.

Reference 2 shows a 2024 balance of (\$25.7 million), with (\$25.2 million) proposed for disposition in this application over 36 months or (\$8.4 million) per year.

Question(s):

- a) Please reconcile the 2024 audited balance of (\$25.7 million) to the (\$25.2 million) proposed for disposition in Reference 2, including the derivation of the (\$0.4 million) already approved amortization amount.
- b) Please provide a breakdown of the 2024 audited balance including, for example:
 - i. Current year variances
 - ii. Prior year true-up entries
 - iii. Audit resolution adjustments
 - iv. Carrying charges
 - v. Any embedded taxes on the difference
- c) Please confirm which components include the associated tax on the ITC difference and show the gross-up calculation.

- 1 d) Please explain how the annual (\$8.4 million) amortization amounts for the SR&ED
2 ITC Variance Account (Nuclear) are reflected in the overall revenue requirement
3 and payment amounts, including whether those amounts are reflected only through
4 riders, or also reflected in any line of the nuclear income tax model in Reference 3.
5
6 e) Please provide the implementation details of the proposed extension of the SR&ED
7 ITC Variance Account (OPG) to the hydroelectric facilities, including:
8 i. The effective date;
9 ii. The transition rule between the historical hydroelectric treatment in the Income
10 and Other Taxes Variance Account and the proposed treatment in the SR&ED
11 ITC Variance Account;
12 iii. A working example showing how a hydroelectric SR&ED ITC variance arising
13 after the effective date would be recorded;
14 iv. Confirmation that no overlap will occur between the two accounts during
15 transition.
16
17

18 **Response**
19

- 20 a) The requested reconciliation can be found at Ex. H1-2-1, Table 2, line 22, cols. (a)
21 to (d). The (\$0.4M) is the sum of the OEB-approved amortization for 2025 of
22 (\$0.2M) and for 2026 of (\$0.2M) from EB-2023-0336 Decision and Order, Appendix
23 A, Table 2, line 21, cols. (h) and (i), respectively.
24
25 b) Refer to Ex. H1-1-1, Table 12 for the breakdown of the 2023 and 2024 additions to
26 the account, including prior-year true-up entries and audit resolution adjustments.
27 Refer to Ex. H1-1-1, Table 1a and 1b, line 38 for the continuity of the balance,
28 including carrying charges for 2023 and 2024, respectively. The opening 2023
29 balance at Ex. H1-1-1, Table 1a, line 38, col. (a) has been approved by the OEB,
30 as per EB-2023-0336 Decision and Order, Appendix A, Table 2, line 21, col. (a).
31
32 c) All five entries into the account in 2023 and 2024, labeled as Entry (i) to (v) in Ex.
33 H1-1-1, Table 12, relate to some manner of SR&ED ITC differences and all contain
34 an income tax “gross-up”. The calculation of the “gross-up” for each of the entries
35 can be seen at lines 9, 16, 19, 22 to 25 of that table.
36
37 d) The annual (\$8.4 million) amortization amounts are reflected only through the
38 payment amount riders as calculated in Ex. H1-2-1, Table 2. For clarity, there is no
39 separate income tax impact included in the regulatory income tax calculations at
40 Ex. F4-2-1, Table 3d in connection with the disposition of this balance.

1 e)

2 i. As noted at Ex. H1-1-1, p. 42, OPG is proposing to apply the same treatment of
3 recording entries in the SR&ED ITC Variance Account for its nuclear facilities to
4 the regulated hydroelectric facilities, as of the effective date of the payment
5 amounts order in this proceeding.

6
7 ii. The “transition rule” would be that any audit resolution adjustments in
8 connection with the regulated hydroelectric facilities in respect of periods prior
9 to the effective date identified in part i) above would be recorded in the Income
10 and Other Taxes Variance Account (OPG). All such adjustments in respect of
11 periods after this effective date would be recorded in the SR&ED ITC Variance
12 Account (OPG). This is the same approach adopted for OPG’s nuclear facilities
13 at the time the account was originally established, effective June 1, 2017.

14
15 iii. As OPG is proposing to record entries in the SR&ED ITC Variance Account
16 (OPG) for the regulated hydroelectric facilities in the same manner as for its
17 nuclear facilities, the account entries for either 2023 or 2024 at Ex. H1-1-1,
18 Table 12 for the nuclear facilities provide a practical example for how entries
19 would also be recorded for the regulated hydroelectric facilities. Each of the five
20 entries for both years are described in Ex. H1-1-1, Section 5.20.

21
22 iv. Confirmed.

Board Staff Interrogatory #252

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 2 / Schedule 1

Preamble:

OPG states that, with the exception of the Rate Smoothing Deferral Account, OPG proposes to recover deferral and variance account (DVA) balances on a straight-line basis over 2027-2029, and that the hydroelectric rate rider includes both hydroelectric DVA amortizations and the income tax impacts associated with the hydroelectric Pension & Other Post-Employment Benefits (OPEB) Cash vs Accrual Differential Deferral Account.

Question(s):

- a) Please provide a reconciliation of the hydroelectric payment rider to the underlying tax-related components only, showing
- i. The annual amortization of the hydroelectric Income and Other Taxes Variance Account
 - ii. The annual amortization of the hydroelectric Tax on Pension & OPEB Cash vs Accrual Differential Deferral line
 - iii. Any other tax-related hydro components included in the rate rider
 - iv. Confirmation that no tax-related amount is recovered both through the rate rider and through the base hydro revenue requirement/C-factor

Response

- a) i. to iii.

The requested information is provided in Chart 1 below.

Chart 1 – Tax Related Amounts Included in Proposed Regulated Hydroelectric Payment Rider

Line	Account	Amounts Recoverable (Refundable) (\$M)	Disposition Period (months)	Amortization Jan - Dec 2027	Amortization Jan - Dec 2028	Amortization Jan - Dec 2029
		(a)	(b)	(c)	(d)	(e)
1	Income and Other Taxes Variance – Hydroelectric ¹	(6.5)	36	(2.2)	(2.2)	(2.2)
2	Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account - Tax-related Component ²	0.3	36	0.1	0.1	0.1
3	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions ³	(10.2)	36	(3.4)	(3.4)	(3.4)
4	Total Recoverable (Refundable) Tax-Related Amounts (lines 1 + 2 + 3)	(16.4)		(5.5)	(5.5)	(5.5)
5	Forecast Production (TWh) ⁴			32.5	32.5	32.5
6	Tax-Related Amounts in Regulated Hydroelectric Payment Rider (\$/MWh) (line 4 / line 5)			(0.17)	(0.17)	(0.17)

¹ Col. (a) calculated as the sum of Ex. H1-1-1, Table 6, line 16, cols. (a) and (d).

² Col. (a) calculated as the sum of Ex. H1-1-1, Table 9, line 13, cols. (a) and (b).

³ Col. (a) per Ex. H1-2-1, Table 1, line 17, col. (d).

⁴ Cols. (c) to (e) per Ex. H1-2-1, Table 1, line 20.

iv. Confirmed.

For clarity, while there is no duplication of *recovery* of income tax impacts between the proposed hydroelectric payment rider and the proposed revenue requirement and C-factor for the regulated hydroelectric facilities over the 2027-2031 period, there is a duplication of *refund* of such impacts to ratepayers in the amount of \$0.5M per year over the 2027-2029 period, as discussed at Ex. L-F4-Staff-220, part b). As explained in that response, OPG does not propose to adjust the approvals sought in the Application on account of this duplication.

Board Staff Interrogatory #253

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Ref 2: Exhibit A1 / Tab 2 / Schedule 3 / pp. 3-6

Preamble:

For the hydroelectric rate setting framework, OPG proposes a revised price-cap index framework for its hydroelectric facilities for the 2027-2031 period. OPG proposes the addition of a capital-factor (C-factor) and GRCF.

The application proposes to change the reference amounts for the existing capital-related variance account (CRVA). The proposal is that the threshold for CRVA additions no longer include the depreciation expense recovery that was available through payment amounts set in EB-2016-0152. The proposal is that the going forward CRVA reference amount only consider the forecast costs related to CRVA-eligible projects, and that the CRVA amounts be reviewed on a five-year cumulative basis.

OPG also proposes to establish an asymmetrical, cumulative Global Hydroelectric Capital Variance Account (GHCVA) that would address a scenario in which the actual capital-related revenue requirement determined based on OPG's actual in-service amounts for the prescribed hydroelectric facilities over the 2028-2031 period is less than the capital-related revenue requirement provided through the payment amounts inclusive of the C-factor.

Question(s):

- a) Please provide an illustrative, numerical example using annual entries over the 2028-2031 period that shows:
 - i. The annual capital-related entries recorded in the hydroelectric CRVA for an eligible portfolio project;
 - ii. The corresponding calculation of the GHCVA based on actual versus forecast capital-related revenue requirement
 - iii. The resulting cumulative adjustment between the CRVA and GHCVA at the end of the 2028-2031 period
 - iv. The final amount, if any, proposed for disposition from each account.

- 1 b) Please provide an illustrative, numerical example for the 2023 and 2024 years had
2 the GHCVA existed. If necessary, please also explain if CRVA entries would have
3 been different had the GHCVA existed.
4
5 c) Please ensure that the example demonstrates how OPG would avoid duplication
6 and how the proposed cumulative limit would be applied in practice.
7
8

9 **Response**

- 10
11 a) OPG understands the CRVA to refer to the Capacity Refurbishment Variance
12 Account rather than a Capital Related Variance Account.
13

14 For continuity with the pre-filed evidence, this response leverages the examples
15 provided in Ex. A1-3-2, Charts 6, 10, 11, 12 and 13 in respect of the interaction
16 between the CRVA and the proposed GHCVA.¹² Further, as explained in that
17 evidence and further discussed below, the interaction between the two accounts is
18 addressed by comparing cumulative balances recorded therein at the end of the
19 last four years of the IR term (i.e., those years where the C-factor is proposed to be
20 in effect). Accordingly, while the question in part (i) is posed in reference to a CRVA
21 eligible project, the response is necessarily framed in the context of the overall
22 CRVA eligible in-service additions over the period.
23

- 24 i. Charts 1 and 2 below provide illustrative examples of annual 2028-2031 capital-
25 related entries in the CRVA for all eligible regulated hydroelectric projects,
26 resulting in credit and debit balances at line 3, respectively, before considering
27 any interaction with the GHCVA. (For clarity, lines 1 and 2 below would comprise
28 multiple projects, with individual project variances offsetting within lines 3, as
29 applicable.) The examples have been designed to match lines 3 at Ex. A1-3-2,
30 Charts 12 and 13 (reproduced as Charts 5 and 6 below), respectively.

¹ The illustrative examples are exclusive of any interest on the account balances.

² The interaction between the GHCVA and the proposed Change of Laws Deferral Account (OPG), with respect to the CRRR of any eligible amounts recorded in the latter account for OPG's regulated hydroelectric facilities, will be addressed analogously with the interaction between the GHCVA and the CRVA as outlined in this response.

Chart 1 – Illustrative Hydroelectric Capital-Related Credit in CRVA (\$M)

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Reference Amount for CRVA Eligible Projects	Ex. H1-1-1, Chart 1, line 1	63.3	171.6	231.1	277.9	
2	Illustrative Actual CRRR for CRVA Eligible Projects	Illustrative only	58.3	166.6	226.1	272.9	
3	Variance: Actual CRRR for CRVA Eligible Project less Reference Amount	line 2 - line 1	(5.0)	(5.0)	(5.0)	(5.0)	(20.0)

Chart 2 – Illustrative Hydroelectric Capital-Related Debit in CRVA (\$M)

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Reference Amount for CRVA Eligible Projects	Ex. H1-1-1, Chart 1, line 1	63.3	171.6	231.1	277.9	
2	Illustrative Actual CRRR for CRVA Eligible Projects	Illustrative only	76.3	183.6	244.1	289.9	
3	Variance: Actual CRRR for CRVA Eligible Projects less Reference Amount	line 2 – line 1	13.0	12.0	13.0	12.0	50.0

- ii. Exhibit A1-3-2, Charts 10 and 11 (reproduced as Charts 3 and 4 below) illustrate the 2028-2031 annual entries into the proposed GHCVA where the actual capital related revenue requirement (“CRRR”) over the period is greater than the forecast CRRR (with the resulting cumulative entry of \$0 at Chart 3, line 4) and where an actual CRRR over the period is lower than the forecast CRRR (with the resulting cumulative entry of (\$40M) at Chart 4, line 4), before considering any interaction with the CRVA. The forecast CRRR at line 1 of Charts 3 and 4 includes the annual reference amounts for the CRVA eligible

projects shown in line 1 of Charts 1 and 2 above. As discussed in Ex. A1-3-2, Section 2.3.5, the GHCVA would be evaluated for disposition in aggregate on a cumulative basis over the last four years of the IR term, with the last year including any adjustment entry necessary to account for the interaction with the CRVA.

Chart 3 – GHCVA Scenario 1 – Actual CRRR is Greater than Forecast (\$M)

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Forecast CRRR (after stretch adjustment)	Ex. A1-3-2, Chart 6, line 7	978.5	1,100.7	1,176.6	1,231.4	
2	Illustrative Actual CRRR	Illustrative only	988.5	1,110.7	1,186.6	1,241.4	
3	Variance: Actual CRRR less Forecast CRRR	line 2 - line 1	10.0	10.0	10.0	10.0	40.0
4	GHCVA Disposition to Ratepayers	Lesser of line 3 and \$0					0.0

Chart 4 – GHCVA Scenario 2 – Actual CRRR is Less than Forecast (\$M)

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Forecast CRRR (after stretch adjustment)	Ex. A1-3-2, Chart 6, line 7	978.5	1,100.7	1,176.6	1,231.4	
2	Illustrative Actual CRRR	Illustrative only	968.5	1,090.7	1,166.6	1,221.4	
3	Variance: Actual CRRR less Forecast CRRR	line 2 - line 1	(10.0)	(10.0)	(10.0)	(10.0)	(40.0)
4	GHCVA Disposition to Ratepayers	Lesser of line 3 and \$0					(40.0)

iii. and iv.

Exhibit A1-3-2, Chart 12 (reproduced as Chart 5 below) illustrates the interaction between the proposed GHCVA and the CRVA if the actual cumulative CRRR is

less than the forecast cumulative CRRR (as is the case for Chart 4 above) and there is a capital-related credit in the CRVA (as is the case for Chart 1 above). In this scenario, to avoid duplicating the amounts refundable through the GHCVA of \$40M and the CRVA of \$20M, the overall refundable amounts are limited to \$40M, representing the actual cumulative CRRR over the 2028-2031 being lower than the forecast cumulative CRRR, and are split between the \$20M credit in the CRVA and the adjusted \$20M credit in the GHCVA.³

Chart 5 – Interaction between GHCVA and CRVA if Actual CRRR is Less than Forecast and Credit in CRVA (\$M)

Line No.	Description	Note	Total
1	Actual CRRR less Forecast CRRR ⁴	Chart 4, line 3	(40.0)
2	Illustrative Capital-Related CRVA Balance Available for Disposition	Chart 1, line 3	(20.0)
3	Illustrative GHCVA Balance Available for Disposition	line 1 – line 2	(20.0)

Exhibit A1-3-2, Chart 13 (reproduced as Chart 6 below) illustrates the interaction between the proposed GHCVA and the CRVA if the actual cumulative CRRR is greater than the forecast cumulative CRRR (as is the case for Chart 3 above) and there is a capital-related debit in the CRVA (as is the case for Chart 2 above). In this scenario, to avoid duplicating the amounts recoverable through the forecast CRRR and the CRVA, the recoverable amounts through the CRVA of \$50M are limited to \$40M, being the amount by which the actual cumulative CRRR exceeds the forecast cumulative CRRR.⁵ (There would be no entries to the GHCVA given its asymmetrical nature in favour of ratepayers.)

³ More broadly, as discussed in Ex. A1-3-2, Section 3.5 and Ex. H1-1-1, Section 5.6, over the 2028-2031 period, (i) the refundability of a credit in the GHCVA would be reduced (not to exceed zero) by a credit in the CRVA, and (ii) the refundability of a credit in the CRVA would be limited to an amount, if any, by which the actual cumulative CRRR is below the forecast cumulative CRRR.

⁴ This line has been incorrectly labelled in Ex. A1-3-2, Chart 12 as “Illustrative GHCVA disposition to ratepayers” and should instead be labelled “Actual CRRR less Forecast CRRR”.

⁵ More broadly, as discussed in Ex. A1-3-2, Section 3.5 and Ex. H1-1-1, Section 5.6, over the 2028-2031 period, the recoverability of a debit in the CRVA would be limited to the amount, if any, by which the actual cumulative CCCR exceeds the forecast cumulative CCCR.

Chart 6 – Interaction of GHCVA and CRVA if Actual CRRR is Greater than Forecast and Debit in CRVA (\$M)

Line No.	Description	Note	Total
1	Actual CRRR less Forecast CRRR	Chart 3, line 3	40.0
2	Illustrative Capital-Related CRVA Balance Available for Disposition	Chart 2, line 3	50.0
3	Illustrative CRVA Balance Available for Disposition	Lesser of line 2 and line 2	40.0

As discussed in Ex. A1-3-2, Section 2.3.5, given the interaction between the GHCVA and the CRVA, the capital-related CRVA balances for the regulated hydroelectric facilities would be evaluated for disposition in aggregate on a cumulative basis over the last four years of the IR term, at the same time as the GHCVA. The disposition of the CRVA entries for the first year of the IR term would not be affected by an interaction with the GHCVA.

- b) OPG is unable to provide the requested example because the payment amounts for the 2023 and 2024 years were not set on the basis of a forecast CRRR that would be necessary to compute entries into a hypothetical GHCVA. Specifically, the 2023 and 2024 hydroelectric payment amounts were set equal to the 2021 hydroelectric payment amount pursuant to Ontario Regulation 53/05, section 6(2)13, while the 2021 hydroelectric payment amount was set using an annual price-cap adjustment that did not contain a C-factor. The 2023 and 2024 hydroelectric payments amounts therefore did not reflect a corresponding CRRR.
- c) Although OPG is unable to provide the requested example in part b), the examples in part a) illustrate how duplication between the GHCVA and the CRVA would be avoided.

Board Staff Interrogatory #254

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 64-65

Ref 2: Exhibit I1 / Tab 3 / Schedule 2 / pp. 6-9

Preamble:

OPG proposes to establish the Payment Amount Shaping Deferral Account (PASDA). An annual deferral amount as determined by the OEB would be recorded in the account from January 1, 2027 until December 31, 2031. This account is proposed in conjunction with OPG's payment amount shaping proposal to help manage the 2027 ratepayer impact while balancing OPG's financing needs over the period.

OPG is currently proposing an amount of \$500 million to be deferred in the account in 2027, to be cleared in 2028. OPG proposes to record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing, as approved by the OEB, compounded annually.

In Reference 2, OPG described the three options it considered for payment amount shaping. Approach A is a status quo scenario with no shaping of proposed payment amounts. Approach B reduces recovery by \$500 million in 2027 and increases recovery by \$500 million in 2028. Approach C reduces recovery by \$500 million in 2027 and increases recovery by \$250 million in 2028, \$50 million in 2029, and \$200 million in 2030. The figures are stated before interest costs that would be associated with the deferral.

Question(s):

- a) Please explain whether OPG considers the PASDA to be a one-time mechanism limited to the proposed deferral of \$500 million from 2027 to be recovered in 2028.
- b) Please provide the forecast interest costs under Approach B and C as at December 31, 2031, as described in Reference 2.
- c) Please confirm whether OPG has considered alternatives to requesting the establishment of the DVA. If other alternatives have been considered, please describe those in detail and why they were not chosen.

Response

a) OPG developed the payment amount shaping proposal specific to this proceeding and therefore intends for the proposed Payment Amount Shaping Deferral Account to be a one-time mechanism.

b) Estimated interest costs over the 2027-2031 period are approximately \$23M under Approach B and approximately \$45M under Approach C, both calculated at OPG's proposed long-term debt rates in this proceeding as explained at Ex. H1-1-1, Section 7.4.

c) The Applicants interpret this request to be asking whether alternative mechanisms to smooth payment amounts in this proceeding were considered.

OPG considered whether the existing Rate Smoothing Deferral Account could be utilized. However, O. Reg. 53/05 section 6(2)12 states that amounts shall be recorded in that account during a deferral period ending when the Darlington Refurbishment Project ends, with recovery commencing thereafter. With the Darlington Refurbishment at or near completion, the account therefore cannot be used to effect payment amount shaping in this proceeding.

OPG also considered adjusting the timing of amortization of deferral and variance account balances proposed for disposition (Ex. H1-2-1, Tables 1 and 2). However, the proposed 2027 amortization amounts are significantly less than \$500M, and OPG therefore did not pursue this alternative.

Board Staff Interrogatory #255

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / p. 1

Preamble:

OPG is not seeking clearance of balances in the following accounts (2024 audited year end balances):

- i. the hydroelectric components of the Capacity Refurbishment Variance Account - \$120.7 million
- ii. the components of the Nuclear Development Variance Account not related to the Darlington New Nuclear Program (DNNP) - \$23.5 million
- iii. Pickering B Variance Account. OPG proposes to defer the clearance of these balances to a future application - \$131.1 million.

Question(s):

- a) For each material balance not proposed for disposition in this application, please provide (in summary format) or explain:
 - i. The additional revenue requirements and bill impacts of disposing the audited 2024 year-end balance, assuming a 36-month disposition period effective January 1, 2027;
 - ii. Whether OPG considered partial disposition;
 - i. If not, why not.
 - iii. Whether continued deferral raises bill impact, carrying charge or intergenerational equity concerns.
 - iv. The forecast carrying charges on the balances at December 31, 2031

Response

- a)
 - i. In responding to this question, OPG has limited the analysis to the non-DNNP components of the Nuclear Development Variance Account and the Pickering B Variance Account. OPG did not perform the analysis for the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA") because, as explained further in Ex. L-H1-Staff-260, part b), the balance in the account cannot be cleared prior to the completion of the 2022-2026 period.

There would be no incremental revenue requirement impact of disposing of the year-end 2024 balances for the non-DNNP components of the Nuclear Development Variance Account and the Pickering B Variance Account. For additional context, in Chart 1 below, OPG provides the illustrative incremental deferral and variance account amortization amounts and residential customer bill impacts that would result over the 2027-2031 period if these balances were cleared over a 36-month period beginning January 1, 2027.

Chart 1 – Illustrative Incremental Deferral and Variance Account Amortization and Residential Customer Bill Impacts

Line	Account	Amount ¹	Disposition Period (months)	Amortization 2027	Amortization 2028	Amortization 2029	Amortization 2030	Amortization 2031
1	Nuclear Development Variance – Non DNNP	23.5	36	7.8	7.8	7.8	0.0	0.0
2	Pickering B Variance	131.1	36	43.7	43.7	43.7	0.0	0.0
3	Total (line 1 + line 2)	154.6		51.5	51.5	51.5	0.0	0.0
4	Change in Typical Residential Bill Impact of Application (\$/Month)			0.3	0.0	0.0	-0.3	0.0
5	Change in Typical Residential Bill Impact of Application (%)			0.2%	0.0%	0.0%	-0.2%	0.0%

¹ From Ex. H1-2-1, Table 2, col. (e), lines 3 and 29, respectively.

- ii. OPG did not consider a partial disposition of the account balances it is not seeking to clear, for the same reasons as outlined in Ex. H1-1-1 and Ex. L-H1-Staff-260 part b).
- iii. The Applicants do not believe that the deferral of the account balances identified in the preamble raises bill impact, carrying charge or intergenerational equity concerns. As discussed in Ex. H1-1-1 and Ex. L-H1-Staff-260 part b), OPG believes that it has a sound rationale for not seeking clearance of these balances in this proceeding, including, with respect to the hydroelectric components of the CRVA, that such deferral is necessary to comply with the terms of the account. Refer to part (iv) below for a discussion of potential future customer bill impacts related to the incremental interest that could be recorded on the balances as a result of deferring their clearance.

Specifically with respect to intergenerational equity considerations for the Pickering B Variance Account, deferring the clearance of the debit balance as of year-end 2024 until offsetting credit entries can be recorded in 2026, all with respect to the continued operation of Pickering Units 5-8, as discussed in Ex. L-

1 H1-Staff-260 part b), supports greater intergenerational equity by matching the
2 benefits of the additional generation in 2026 with the preceding years' costs
3 incurred to enable these benefits.
4

- 5 iv. OPG is unable to provide a forecast of the carrying charges on the balances in
6 question as of December 31, 2031, as developing such a forecast would require
7 forecasts of future account additions (where applicable), the OEB's prescribed
8 interest rates for deferral and variance accounts, and the timing of future
9 disposition, all over a six-year period.
10

11 For illustrative purposes, OPG has estimated the hypothetical cumulative
12 carrying charges that would be recorded on the year-end 2026 forecasted
13 balances (as provided in Ex. L-A1-CCC-001) over the 2027-2031 period,
14 assuming a prescribed deferral and variance account interest rate of 2.55%, no
15 post-2026 additions and no disposition through December 31, 2031. Such
16 aggregate interest as of December 31, 2031 for these balances would be
17 approximately \$33M for the hydroelectric components of the CRVA, \$25M for
18 the non-DNNP components of the Nuclear Development Variance Account and
19 approximately (\$17M) for the Pickering B Variance Account, for a net amount
20 recoverable of approximately \$42M. This net amount is order-of-magnitude
21 equivalent to about 0.1% of a typical residential customer bill. Should these
22 balances be disposed of as part of a separate deferral and variance account
23 application submitted during the 2027-2031 period, the clearance would likely
24 commence sooner than in the above scenario and the interest impacts would
25 be smaller.

Board Staff Interrogatory #256

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / pp. 40-41

Preamble:

OPG is proposing to recover the Rate Smoothing Deferral Account year-end 2024 balance of \$677.4 million over the maximum prescribed period of ten years, from January 1, 2027 to December 31, 2036 in the Rate Smoothing Deferral Account.

According to O. Reg. 53/05, an annual deferral amount as determined by the OEB is recorded in the account from January 1, 2017 until the Darlington Refurbishment Project (DRP) ends (the “deferral period”). Section 6(2)12(iv) of O. Reg. 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account and shall authorize recovery of the account balance on a straight-line basis over a period not to exceed ten years commencing at the end of the deferral period.

With the DRP expected to return the last unit to service in 2026, no additions are anticipated to be required to the account as of the effective date of the payment amounts order in this proceeding. Section 5.5(2) of O. Reg. 53/05 stipulates that the deferral account shall record interest on the balance of the account at OPG’s long-term debt rate, compounded annually.

Question(s):

- a) Please explain the rationale of proposing the maximum 10-year disposition period for the Rate Smoothing Deferral Account compared to shorter disposition periods.
- b) Please provide an analysis, with interest costs shown separately, showing the additional cost and bill impacts if the balance was disposed over 3 years, 5 years, and 7 years.

Response

- a) As noted at Ex. H1-2-1, p. 3, lines 13-15, OPG is proposing the maximum 10-year disposition period for the Rate Smoothing Deferral and Variance Account permitted by O. Reg. 53/05, Section 6(2)12(iv) due to its larger size compared to OPG’s other deferral and variance account balances, which the Application proposes to clear

over a three-year period, and this would help to mitigate customer bill impacts arising from the Application.

- b) An illustrative analysis for the requested scenarios is presented in Charts 1 to 4 below, based on the year-end 2024 balance in the account. The analysis calculates interest over the 2027-2031 period at the corresponding proposed OPG's cost of long-term debt per Ex. C1-1-1, Tables 1 to 5. The 2031 cost of long-term debt is held constant for the subsequent years. Where applicable, for simplicity, the analysis assumes that any year-end 2031 balance in the account would be cleared over the 2032-2036 period on a straight-line basis, and the amortization of any residual interest that would be accumulated during that period is not shown. The analysis reflects the format, methodology and applicable inputs used to produce Ex. I1-1-2, Table 1 that determines the estimated typical residential consumer bill impacts of the Application.

Chart 1 – Illustrative Summary of Amortization, Interest Costs and Bill Impacts of Proposed 10-Year Disposition Period for Rate Smoothing Deferral Account

Line	Particulars	2027	2028	2029	2030	2031	2032-2036	2027-2036
1	Amortization – EB-2025 (\$M)	(67.7)	(67.7)	(67.7)	(67.7)	(67.7)	(338.7)	(677.4)
2	Amortization – Post-2031 (\$M)	0.0	0.0	0.0	0.0	0.0	(200.3)	(200.3)
3	Interest (\$M)	31.8	31.5	30.5	29.0	27.2	77.1	227.0
4	Typical Residential Bill Impact of Application	\$7.93 5.6%	\$2.44 1.7%	\$1.33 0.9%	\$0.69 0.5%	\$4.62 3.3%	N/A	N/A

Chart 2 – Illustrative Summary of Amortization, Interest Costs and Bill Impacts of 7-Year Disposition Period for Rate Smoothing Deferral Account

Line	Particulars	2027	2028	2029	2030	2031	2032-2036	2027-2036
1	Amortization – EB-2025 (\$M)	(96.8)	(96.8)	(96.8)	(96.8)	(96.8)	(193.5)	(677.4)
2	Amortization – Post-2031 (\$M)	0.0	0.0	0.0	0.0	0.0	(181.3)	(181.3)
3	Interest (\$M)	31.1	29.4	26.8	23.7	20.1	37.5	168.5
4	Typical Residential Bill Impact of Application	\$8.07 5.7%	\$2.42 1.7%	\$1.33 0.9%	\$0.69 0.5%	\$4.62 3.3%	N/A	N/A
<i>Difference to 10-Year Disposition Period:</i>								
5	Amortization – EB-2025 (\$M)	(29.0)	(29.0)	(29.0)	(29.0)	(29.0)	145.1	-
6	Amortization – Post-2031 (\$M)	0.0	0.0	0.0	0.0	0.0	18.9	18.9
7	Interest (\$M)	(0.7)	(2.1)	(3.7)	(5.4)	(7.1)	(39.6)	(58.5)
8	Typical Residential Bill Impact of Application	\$0.14 0.1%	\$(0.02) 0.0%	\$0.00 0.0%	\$0.00 0.0%	\$0.00 0.0%	N/A	N/A

**Chart 3 – Illustrative Summary of Amortization, Interest Costs and Bill Impacts
of 5-Year Disposition Period for Rate Smoothing Deferral Account**

Line	Particulars	2027	2028	2029	2030	2031	2032- 2036	2027- 2036
1	Amortization – EB-2025 (\$M)	(135.5)	(135.5)	(135.5)	(135.5)	(135.5)	-	(677.4)
2	Amortization – Post-2031 (\$M)	0.0	0.0	0.0	0.0	0.0	(156.1)	(156.1)
3	Interest (\$M)	30.2	26.5	21.8	16.5	10.6	22.3	128.0
4	Typical Residential Bill Impact of Application	\$8.26 5.8%	\$2.39 1.7%	\$1.33 0.9%	\$0.68 0.5%	\$4.61 3.2%	N/A	N/A
<i>Difference to 10-Year Disposition Period:</i>								
5	Amortization – EB-2025 (\$M)	(67.7)	(67.7)	(67.7)	(67.7)	(67.7)	338.7	-
6	Amortization – Post-2031	0.0	0.0	0.0	0.0	0.0	44.2	44.2
7	Interest (\$M)	(1.6)	(4.9)	(8.6)	(12.5)	(16.6)	(54.7)	(98.9)
8	Typical Residential Bill Impact of Application	\$0.33 0.2%	\$(0.05) 0.0%	\$0.00 0.0%	\$(0.01) 0.0%	\$(0.01) 0.0%	N/A	N/A

Chart 4 – Illustrative Summary of Amortization, Interest Costs and Bill Impacts of 3-Year Disposition Period for Rate Smoothing Deferral Account

Line	Particulars	2027	2028	2029	2030	2031	2032-2036	2027-2036
1	Amortization – EB-2025 (\$M)	(225.8)	(225.8)	(225.8)	-	-	-	(677.4)
2	Amortization – Post-2031	0.0	0.0	0.0	0.0	0.0	(119.9)	(119.9)
3	Interest (\$M)	28.1	20.0	10.4	5.4	5.7	17.1	86.7
4	Typical Residential Bill Impact of Application	\$8.69 6.1%	\$2.32 1.6%	\$1.35 1.0%	\$(0.42) -0.3%	\$4.64 3.3%	N/A	N/A
<i>Difference to 10-Year Disposition Period:</i>								
5	Amortization – EB-2025 (\$M)	(158.0)	(158.0)	(158.0)	67.7	67.7	338.7	-
6	Amortization – Post-2031 (\$M)	0.0	0.0	0.0	0.0	0.0	80.4	80.4
7	Interest (\$M)	(3.6)	(11.5)	(20.1)	(23.6)	(21.5)	(59.9)	(140.3)
8	Typical Residential Bill Impact of Application	\$0.76 0.5%	\$(0.12) -0.1%	\$0.02 0.1%	\$(1.11) -0.8%	\$0.02 0.0%	N/A	N/A

Board Staff Interrogatory #257

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

OPG proposes several new deferral and variance accounts in this application including, but not necessarily limited to, the Global Hydroelectric Capital Variance Account, Payment Amount Shaping Deferral Account, Change of Laws Deferral Account (OPG), and Clean Electricity Investment Tax Credit Variance Account (OPG).

Question(s):

- a) If the account is not expressly established by regulation, a discussion of why the proposed account is appropriate, including:
 - i. Causation, i.e. why the proposed amounts are outside the forecast amounts or rate base on which payments amounts were derived
 - ii. Materiality, including an estimate of the expected magnitude of the balance and why it is expected to be material
 - iii. Prudence, i.e. how OPG will identify and record the proposed amounts reliably
- b) Please explain why the underlying cost, credit, or risk is not part of OPG's ordinary business risk.
- c) Please provide a draft accounting order including illustrative entries.

Response

- a) The requested information is provided below.^{1,2}

Global Hydroelectric Capital Variance Account

Causation

The Global Hydroelectric Capital Variance Account is proposed in conjunction with the requested hydroelectric rate-setting framework in Ex. A1-3-2, Section 2.0. The account is designed to address a scenario where the capital-related revenue

¹ The discussion does not include those accounts proposed by DNNP LP that mirror applicable existing accounts for OPG.

² The discussion does not include the proposed DNNP Nuclear Liability Deferral, which OPG views as being necessary to enable the operation of O. Reg. 53/05, section 6(2)10.1.

1 requirement determined based on OPG's actual capital in-service amounts for the
2 prescribed hydroelectric facilities over the 2028-2031 period is less than the capital-
3 related revenue requirement afforded through the payment amounts inclusive of
4 the proposed C-factor. As the account is asymmetric in favour of ratepayers, the
5 only amounts that could be recorded in the account are credit amounts due to the
6 actual capital-related revenue requirement being lower than such amount
7 underpinning the C-factor. Thus, by their nature, these potential credit amounts are
8 outside the forecast amounts that would underpin payment amounts.

9 10 **Materiality**

11 In Ex. A1-3-2, Section 4.3, the Applicants propose to increase the regulatory
12 materiality threshold applicable to OPG's regulated hydroelectric and nuclear
13 businesses to \$20M. The capital-related revenue requirements underpinning the
14 C-factor are \$978.5M in 2028, \$1,100.7M in 2029, \$1,176.6M in 2030, and
15 \$1,231.4M in 2031.³ A \$20M variance would represent approximately 2% of these
16 annual amounts. While OPG does not anticipate variances in a particular direction,
17 on a portfolio of this size, it is inherently plausible that a variance of 2% or greater
18 could materialize.

19 20 **Prudence**

21 The nature of the amounts and the proposed process for recording them in the
22 account is detailed in Ex. A1-3-2, Section 2.3.5, and further discussed in Ex. L-H1-
23 Staff-253.

24 25 Payment Amount Shaping Deferral Account

26 **Causation**

27 As stated in Ex. H1-1-1, p. 65, the Payment Amount Shaping Deferral Account "is
28 proposed in conjunction with OPG's payment amount shaping proposal to help
29 manage the 2027 ratepayer impact while balancing OPG's financing needs over
30 the period." The proposal to defer collection of OPG's 2027 recoverable nuclear
31 revenue requirement by \$500M in 2027 and increase it by \$500M in 2028
32 demonstrates, by its nature, that the amount recorded in the account would be
33 outside the forecasts that otherwise underpin the payment amounts.

34 35 **Materiality**

36 The proposed annual deferral amounts of \$500M in 2027 and \$(500)M in 2028
37 exceed the proposed regulatory materiality threshold of \$20M.

38 39 **Prudence**

40 The nature of the amounts and the proposed process for recording them in the
41 account is detailed in Ex. H1-1-1, Section 7.4 and Ex. I1-3-2.

42

³ Ex. I1-2-1, Table 2, line 7.

Change of Laws Deferral Accounts (OPG and DNNP LP accounts)

Causation

As noted in Ex. H1-1-1, p. 61:

[OPG's] 2025-2031 Business Plan and **the proposed forecasts in this Application do not include any changes in laws that may occur over the IR term** unless captured by an existing account. As such, OPG proposes to establish a deferral account to capture material cost and revenue impacts to OPG's regulated hydroelectric and nuclear facilities arising from provincial and/or federal legislative or regulatory changes..., to the extent these impacts are not already recorded in other deferral and variance accounts.

Emphasis added.

The highlighted statement noting that the forecasts underpinning the Application do not include changes in law supports the causation criteria. The account is proposed to address impacts that are entirely outside the costs proposed for recovery, and the production forecasts over which such recovery is proposed, by the Applicants in this Application. An illustrative example of the type of impacts that would be eligible for recording in the account is provided in Ex. L-H1-SEC-214.

Materiality

As described above, the Applicants are proposing that the accounts only capture material cost and revenue impacts. The Applicants propose to determine materiality for the purposes of the Change of Laws Deferral Accounts using the proposed materiality thresholds of \$20M for OPG and \$10M for DNNP LP under the respective rate-setting frameworks, as set out in Ex. A1-3-2, Section 4.3, on an annualized revenue requirement or revenue basis, as applicable.

Prudence

In Ex. H1-1-1, pp. 62-63, OPG provides an explanation of how the account could operate using American eel legislation as an example. In that exhibit, OPG states that "if OPG's regulated hydroelectric facilities are faced with compliance activities related to such changes over the 2027-2031 IR term, OPG would use the proposed Change of Laws Deferral Account (OPG) to record the revenue requirement impact of costs associated with these compliance activities, as well as the impact of foregone production revenue, net of changes in GRC costs, at OPG's regulated hydroelectric facilities." Further discussion on the mechanics of these proposed accounts and how the interactions with existing accounts are proposed to be addressed can be found in Ex. L-H1-Staff-259.

1 The Applicants propose that this process would be followed for any potential
2 material change in legal or regulatory requirement during the IR term. This process
3 would ensure that potential impacts on all elements of revenue requirement and
4 production revenue are addressed holistically.

5
6 Clean Electricity ITC Variance Accounts (OPG and DNNP LP)

7 **Causation**

8 As stated at Ex. H1-1-1, pp. 63 and 70, “no legislation implementing this credit is in
9 place and the CEITCs are not reflected in OPG’s 2025-2031 Business Plan or the
10 proposed revenue requirements in this Application”. This supports the causation
11 criteria, demonstrating that amounts are outside the forecasts that would be
12 underpinning the payment amounts. Furthermore, while legislation instituting the
13 Clean Electricity Investment Tax Credit (“CEITC”) has since become law on March
14 26, 2026, had this event occurred prior to the filing date of the Application and
15 forecasted impacts of the CEITCs had been reflected in the revenue requirement,
16 the causation criteria would still have been met given the uncertainties regarding
17 the meeting of specific eligibility requirements and the actual amounts of the
18 CEITCs received, as further discussed in Ex. L-F4-CCC-084.

19
20 **Materiality**

21 Refer to Ex. L-F4-CCC-084 for the estimated impact related to the CEITCs on the
22 respective proposed revenue requirements in the Application. On average, these
23 impacts exceed the proposed \$20M materiality threshold for OPG’s facilities and
24 the proposed \$10M materiality threshold for the DNNP facilities.

25
26 **Prudence**

27 The nature of the amounts and the proposed process for recording them in the
28 account is presented in Ex. H1-1-1, Sections 7.3 and 8.6, and Ex. F4-2-1, Section
29 3.5.

30
31 As described in Ex. F4-2-1, p. 20, “the recognized CEITCs will reduce in-service
32 rate base, associated depreciation expense and cost of capital amounts and the
33 attendant tax effects, while reducing the available CCA deductions”. This is the
34 basis for the revenue requirement impact of the CEITCs that the Applicants propose
35 to record in the Clean Electricity ITC Variance Accounts. This basis is
36 comprehensively illustrated in Ex. L-F4-CCC-084, Attachment 1 materials.

37
38 Impact of Change in Tax Status Variance Account (DNNP)

39 **Causation**

40 As discussed in Ex. H1-1-1, Section 8.7, the Impact of Change in Tax Status
41 Variance Account (DNNP) is proposed “to record the impact on the forecast
42 regulatory income taxes reflected in revenue requirement approved by the OEB
43 from any changes to the tax status of DNNP LP’s partners.” With DNNP LP’s

1 partners, rather than DNNP LP itself as a limited partnership, being subject to
2 income tax, this account is necessary in the event that the regulatory income taxes
3 included in DNNP LP's revenue requirements do not reflect the correct tax status
4 of the DNNP LP partners. As discussed in Ex. F4-3-2, p. 4, lines 6-21, the non-
5 OPG partners are currently tax exempt and there is therefore no tax allowance
6 considered in the proposed revenue requirements in respect of their ownership
7 portion. On this basis, the potential amounts eligible for the account are inherently
8 outside the forecasts underpinning payment amounts.

9
10 **Materiality**

11 The potential magnitude of amounts recorded in the account depends on the share
12 of partnership taxable income attributable to the partner(s) subject to a change in
13 tax status.

14
15 **Prudence**

16 DNNP LP proposes to determine the impact on the forecast regulatory income
17 taxes reflected in revenue requirement by recalculating the income tax expense
18 amounts at Ex. I1-1-1, Table 2a, line 21 and Ex. F4-2-1, Table 3g using the tax
19 status of the partners after a change in status.

- 20
21 b) In the case of the Global Hydroelectric Capital Variance Account and the Payment
22 Amount Shaping Deferral Account, the accounts are proposed in conjunction with
23 elements of the Applicants' proposed rate-setting frameworks. These accounts are
24 not designed to reduce business risk.

25
26 In the case of the Clean Electricity ITC Variance Accounts and Impact of Change
27 in Tax Status Variance Account, the accounts are proposed to address uncertainty
28 at the time of filing. The Clean Electricity ITC Variance Accounts ensure that
29 ratepayers receive applicable tax benefits if realized by the Applicants; they are not
30 designed to reduce business risk.

31
32 As noted above in the response to part a), the Impact of Change in Tax Status
33 Variance Account is necessary in the event that the regulatory income taxes
34 included in DNNP LP's revenue requirements do not reflect the correct tax status
35 of the DNNP LP partners. This potential for a partner to become subject to tax is
36 not an ordinary business risk for DNNP LP.

37
38 With respect to the Change of Laws Deferral Accounts, the purpose of the accounts
39 is to address changes in laws and regulations that are outside of the Applicants'
40 control and have material impact on costs and revenues. While the Applicants
41 monitor potential development in this area, they are unable to predict whether any
42 particular laws or regulation changes will ultimately materialize. The Applicants also
43 believe that the making of the request for the account during this proceeding, prior

- 1 to any settlement or decision, is consistent with the OEB's decision in EB-2023-
2 0098, that where OPG identified a known variable, "OPG should have taken into
3 consideration and governed themselves accordingly, for example by identifying the
4 issue and also by seeking a specific variance account as part of their application."
5
6 c) Refer to Ex. L-H1-SEC-204.

Board Staff Interrogatory #259

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 60-63, 71-72

Ref 2: Exhibit A1 / Tab 6 / Schedule 1

Ref 3: Exhibit A1 / Tab 6 / Schedule 1 / Attachment 3

Preamble:

At Reference 1, the Applicants propose a “Change of Laws Deferral Account” for each of OPG and DNNP LP. The filed evidence describes a proposal where this account would record material impacts to both costs and revenues. At Reference 2, OPG summarizes and explains the legislative framework under which OPG operates and DNNP LP will operate.

Reference 3 is Ontario Power Generation Inc.’s Electricity Generation Licence, which has provisions for changes in law.

Question(s):

- f) Please explain if the proposed account would overlap with the change in law provisions in the licence and if there is overlap, how OPG proposes to address that overlap.
- g) Please explain how OPG proposes to address situations where the Changes of Laws Deferral Account would record material impacts to costs that also relate to other approved and proposed accounts, such as situations where the proposed account captures capital expenditures are deemed to have resulted in “material costs.”
- h) Please explain how OPG proposes to address situations where the Changes of Laws Deferral Account would record material impacts to revenues that also relate to other approved or proposed accounts.

Response

- f) The proposed account does not overlap with the change in law provisions in OPG’s Electricity Generation Licence since that change in law provision applies to Part 2

1 (Price Cap and Rebate) of the Licence which is subject to Schedule B of the Licence
2 applicable until April 30, 2009.

3
4 g) and h)

5
6 As noted at Ex. H1-1-1, p. 61, lines 9-13, and Ex. H1-1-1, p. 72, lines 1-5, the
7 Applicants propose to establish respective deferral accounts to capture material
8 cost and revenue impacts to OPG's regulated hydroelectric and nuclear facilities,
9 and the DNNP facilities, arising from provincial and/or federal legislative or
10 regulatory changes (collectively, "change in law(s)"), to the extent these impacts
11 are not recorded in other deferral and variance accounts. As such, any material
12 impacts to costs or revenues resulting from a change in laws would be first
13 evaluated for eligibility under the other accounts in place at the time.

14
15 For example, if a change in law results in OPG incurring an incremental nuclear
16 capital expenditure that is part of a project eligible for the Capacity Refurbishment
17 Variance Account ("CRVA"), the associated revenue requirement impact of such
18 costs would be captured in the CRVA, rather than the Change of Laws Deferral
19 Account (OPG). On the other hand, if such incremental nuclear capital expenditure
20 is not eligible for the CRVA, its revenue requirement would be captured in the
21 Change of Laws Deferral Account (OPG).

22
23 Further details regarding the interaction of the proposed Change of Laws Deferral
24 Account (OPG) with OPG's other income tax related deferral and variance accounts
25 can be found at Ex. L-H1-Staff-248.

26
27 A discussion of the proposed materiality thresholds to be applied to the Change of
28 Laws Deferral Accounts can be found at Ex. L-H1-CCC-106.

Board Staff Interrogatory #260

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / p. 1

Ref 2: Clarification on Filing Requirements for Ontario Power Generation Inc. and Policy Report Retirements

Ref 3: Exhibit H1 / Tab 2 / Schedule 1 / p. 1

Ref 4: OPG Reporting to the OEB

Preamble:

With Reference 1, OPG identifies that it is not seeking clearance of certain deferral and variance account (DVA) balances. Transaction details for these accounts have not been filed.

On page 2 of Reference 2, the OEB confirmed to OPG that “OPG is not required to file bridge year information as part of its DVA schedules in cases where DVAs are proposed to be cleared on the basis of audited actual information.” At Reference 3 OPG identifies that OPG proposes to clear the DVA on the basis of audited balances.

Except for parts e) and f), please file all of these responses in excel format in a manner consistent with the Tables to Exhibit H1 in the same form as previous applications seeking disposition of DVA balances.

Question(s):

- a) Please provide a Continuity of Account Balances for the Year-Ended December 31, 2025, as in H1-1-1 Table 1b, for DVA balances. Please ensure reconciliation to the 2025 Q4 balances filed with the OEB as per Reference 4.
- b) Please provide transaction details for the 2023 and 2024 accounting activities for:
 - i. The hydroelectric components of the Capacity Refurbishment Variance Account,
 - ii. The non-Darlington New Nuclear Program (DNNP) components of the Nuclear Development Variance Account, and
 - iii. The Pickering B Variance Account.
- c) Please provide transaction details for 2025 for:
 - i. The hydroelectric components of the Capacity Refurbishment Variance Account,
 - ii. The nuclear components of the Capacity Refurbishment Variance Account,

- iii. The hydroelectric Water Conditions Variance Account,
- iv. The hydroelectric Surplus Generation Variance Account,
- v. The Nuclear Liability Deferral Account,
- vi. The non-DNNP components of the Nuclear Development Variance Account,
and
- vii. The Pickering B Variance Account.

- d) Please provide an updated H1-1-1 Table 1 that adds 2025 balances and 2026 forecast. Please add to this table any deferral and variance accounts that are not listed in the as filed H1-1-1 Table 1.
- e) Please list all OPG and DNNP LP deferral and variance accounts that are not listed in H1-1-1 Table 1. Please explain OPG's and DNNP LP's outlook for these accounts for 2026 and whether transactions are expected in the rate term. As part of this response, please explain OPG's and DNNP LP's forecast, or outlook of potential ranges of outcomes, relating to the potential balances at the end of 2026 in the Darlington New Nuclear Project Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project Variance Account.
- f) For any DVAs with a nil balance at December 31, 2024 and not proposed for termination in this application, please confirm whether entries are expected in the 2027-2031 rate term and OPG's proposal for continuance/termination of those DVAs.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

- a) Refer to Attachment 1, Table 1c.
- b) Refer to Attachment 3 for the actual 2022-2025 transaction details for the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA"), provided in a similar manner as EB-2023-0336, Ex. H1-1-1, Tables 7-7d. A forecast of such 2026 transaction details is also included in Attachment 3, given that the account methodology requires inputs for the full 2022-2026 IR term, as discussed below. The resulting additions for the hydroelectric components of the CRVA are presented as follows in Attachment 3:
 - For the capital portion related to amounts placed in service prior to June 1, 2017, refer to Table 1, line 15;
 - For the non-capital portion, refer to Table 1, line 18;

- For the capital portion related to amounts placed in service between June 1, 2017 and December 31, 2021, refer to Table 1b, line 10; and
- For the capital portion related to amounts placed in service since January 1, 2022, refer to Table 1e, line 3.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that information on these transaction details is not relevant, as the Application is not seeking the clearance of these balances, as set out at Ex. H1-1-1, p. 18, lines 18-22. Further details with respect to these reasons are provided below.

OPG declines to provide the requested information for the non-Darlington New Nuclear Program (“DNNP”) components of the Nuclear Development Variance Account and the Pickering B Variance Account on the basis of relevance, as the Application is not seeking the clearance of these balances, as set out at Ex. H1-1-1, p. 39, lines 12-17 and p. 53, lines 4-9. Further details with respect to these reasons are provided below for each of these two accounts.

Capacity Refurbishment Variance Account – Hydroelectric Components

For the hydroelectric components of the CRVA, consistent with the processes established and applied in past proceedings¹ and affirmed by the OEB in the EB-2020-0290 Payment Amount Order,² OPG can only seek recovery after the end of an IR period when it can confirm that the corresponding capital additions exceeded implicit funding in base payment amounts. Since the information for the current 2022-2026 IR term is unavailable until the term concludes, the recoverable amount in the account cannot be determined or cleared during this proceeding.

Pickering B Variance Account

With respect to the Pickering B Variance Account, OPG is not seeking clearance of this debit balance as of year-end 2024, with offsetting credit entries expected in the account during 2026, such that the cumulative balance would be a net credit to customers, as shown in Attachment 2, Table 1, line 46, col. (e). In accordance with the scope of the account established by O. Reg. 53/05, the debit entries as of year-end 2024 (and during 2025) relate to foregone revenues related to forgone output from Pickering Units 5-8 arising from their extension (and preservation) activities, together with the revenue requirement impacts arising from the costs incurred for

¹ EB-2016-0152 Decision and Order, December 28, 2017, p. 114. This approach was also applied in EB-2018-0243 (see Ex. H1-1-1, p. 10, lines 25-29), EB-2020-0290 (see Ex. H1-1-1, p. 18, lines 15-18), and EB-2023-0336 (see Ex. H1-1-1, p. 15, lines 14-17).

² EB-2020-0290 Payment Amounts Order, App. E, p. 8, line 17 to p. 9, line 1.³ Extension activities are those undertaken in furtherance of the operation of these units from January 1, 2026 to September 30, 2026 and preservation activities are those undertaken to preserve the ability to operate Pickering Units 5-8 following their return from refurbishment.

1 extension and preservation activities.³ The credit entries during 2026 will be on
2 account of the revenues generated from the output of Pickering Units 5-8 during
3 the January 1, 2026 to September 30, 2026 period.⁴
4

5 Clearing the year-end 2024 debit balance in this proceeding, to be followed by a
6 later clearance of a net credit balance that would accumulate over the 2025-2026
7 period, would split out the recovery of costs incurred to help generate the additional
8 revenue from the return of such revenues to customers. This would increase the
9 near-term impact on customers and would be inconsistent with the “benefits follow
10 costs” principle. It would also introduce inefficiency to the regulatory proceedings,
11 resulting in the account being reviewed twice. As stated at Ex. H1-1-1, Section 5.28,
12 deferring the clearance of the balance to a future application would allow for the
13 complete impact of operating Pickering Units 5-8 from January 1, 2026 to
14 September 30, 2026 to be considered at the same time.
15

16 Nuclear Development Variance Account – Non-DNNP Components

17 The non-DNNP components of the Nuclear Development Variance Account
18 represent non-capital costs incurred related to ongoing planning and preparatory
19 activities for potential new nuclear generation on OPG sites, including the
20 Wesleyville site, consistent with the Province’s plans to meet Ontario’s electricity
21 needs. As discussed at Ex. H1-1-1, p. 39, while it is possible to dispose of this 2024
22 year-end balance in this proceeding, OPG believes it is more appropriate to defer
23 its disposition to a future application once these initiatives have further progressed.
24 As noted in Ex. F2-1-1, Section 5.1, the proposed nuclear revenue requirements in
25 this Application do not include non-capital or capital costs for potential new nuclear
26 facilities other than the DNNP; these costs are not an Issue on the Issues List in for
27 this proceeding. Any such costs incurred during the IR term would continue to be
28 recorded in this account and, in OPG’s view, addressing these costs in aggregate
29 in a future proceeding would enable the company to provide more comprehensive
30 supporting evidence and allow interested parties a fuller opportunity to review it,
31 while promoting regulatory efficiency across proceedings. This approach is
32 consistent with the treatment of non-capital preliminary planning and preparation
33 costs recorded in the account with respect to the then-potential development of
34 small modular reactors at the Darlington New Nuclear site over the 2020-2021
35 period. Those costs were fully recorded in the account before being brought forward
36 for disposition in EB-2023-0336, once the initiative had transitioned to the first
37 phase of the resulting capital project, being the DNNP.

³ Extension activities are those undertaken in furtherance of the operation of these units from January 1, 2026 to September 30, 2026 and preservation activities are those undertaken to preserve the ability to operate Pickering Units 5-8 following their return from refurbishment.

⁴ In accordance with O. Reg. 53/05, the Pickering B Variance Account would cease recording additions as of the effective date of the OEB’s payment amounts order in this proceeding.

1 c) Refer to Attachment 1 for the actual 2025 transaction details of the nuclear
2 components of the CRVA (Tables 13 to 16), the Hydroelectric Water Conditions
3 Variance Account (Table 2), the Hydroelectric Surplus Baseload Generation
4 Variance Account (Table 5), and the Nuclear Liability Deferral Account (Table 17).

5
6 Refer to Attachment 3 for the actual 2022-2025 transaction details for the
7 hydroelectric components of the CRVA, which, as discussed in part b) of this
8 response, are provided in accordance with the Motions Resolutions letter filed on
9 May 4, 2026.

10
11 For the reasons set out in part b) of this response, OPG declines to provide the
12 requested information for the the non-DNNP components of the Nuclear
13 Development Variance Account and the Pickering B Variance Account.

14
15 d) Refer to Attachment 2, Table 1.

16
17 e) Refer to Attachment 2, Table 2 for a projection of the 2026 account transactions
18 and the year-end 2026 balances in the Applicants' deferral and variance accounts,
19 in the form of the continuity schedules filed at Ex. H1-1-1, Tables 1a and 1b. This
20 includes the Darlington New Nuclear Project Variance Account re Capital Cost
21 Amounts and the Pickering B Refurbishment Project Variance Account, which 2026
22 projected additions are as set out at Ex. I1-1-1, Table 6, line 7, col. (a) and Ex. I1-
23 1-1, Table 7, line 7, col. (a), respectively.

24
25 The above projections are based on the 2026 budgets in OPG's 2025-2031
26 Business Plan and DNNP LP's 2026-2031 Business Plan as reflected in this
27 Application. The Applicants have not assessed a range of potential projections for
28 these balances; any projection depends on a host of variables that are outside of
29 OPG's control.

30
31 Provided below is a list of the Applicants' currently authorized deferral and variance
32 accounts that are not listed in Ex. H1-1-1, Table 1:

- 33 • Gross Revenue Charge Variance Account
- 34 • IFRS Deferral Account (OPG)
- 35 • Earnings Sharing Deferral Account
- 36 • Pickering B Refurbishment Project Variance Account
- 37 • Darlington New Nuclear Project Variance Account
- 38 • Incremental Cloud Computing Implementation Costs Deferral Account
- 39 • Darlington New Nuclear Project Variance Account re Development
- 40 • Darlington New Nuclear Project Variance Account re Capital Cost Amounts
- 41 • DNNP Generator Capital Structure Variance Account.

1 With the exception of the Incremental Cloud Computing Implementation Costs
2 Deferral Account that the Applicants have proposed be terminated as of the
3 effective date of the payment amounts order in this proceeding, all of the above
4 accounts could have transactions during the IR term. Further details on these
5 accounts can be found in Ex. H1-1-1.

- 6
7 f) OPG confirms that all deferral and variance accounts with a nil balance at
8 December 31, 2024 and that are not proposed for termination in this Application
9 could have entries for additions, amortization or interest during the IR term. OPG
10 has not developed proposals for these accounts beyond this Application. For the
11 reasons set out in Ex. H1-1-1, Section 5.11, no additions are expected to the
12 Pension & OPEB Cash Versus Accrual Differential Deferral Account as of the
13 effective date of the payment amounts order in this proceeding.

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2022, 2023, 2024 and 2025 (\$M)

Line No.	Account	Note	Actual Year End Balance 2022	Actual Year End Balance 2023	Actual Year End Balance 2024	Actual Year End Balance 2025
			(a)	(b)	(c)	(d)
			Note 1	Note 2	Note 3	Note 4
	Regulated Hydroelectric:					
1	Hydroelectric Water Conditions Variance		(172.4)	(185.6)	(172.6)	(118.9)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(34.3)	(31.5)	(22.2)	(60.7)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		401.8	393.3	305.6	214.3
5	Income and Other Taxes Variance - Hydroelectric		(13.3)	(17.3)	(17.3)	(15.5)
6	Capacity Refurbishment Variance - Hydroelectric		80.4	95.7	162.1	218.9
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.0	8.8	8.6	8.3
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		2.1	1.1	0.0	0.0
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		33.0	24.8	16.5	8.3
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		14.0	7.0	0.0	0.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		35.3	26.5	17.7	8.8
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		28.1	8.4	(8.0)	(25.4)
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(77.0)	(83.5)	(76.3)	(75.5)
14	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	5	(2.0)	(4.9)	(8.5)	(12.4)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		16.1	17.3	16.7	18.4
16	Regulated Hydroelectric Subtotal		319.9	260.0	222.3	168.6
	Nuclear:					
17	Nuclear Liability Deferral		188.3	377.5	527.3	454.1
18	Nuclear Development Variance - DNNP		110.9	106.7	61.8	63.9
19	Nuclear Development Variance - Non-DNNP		0.0	7.8	23.5	64.2
20	Ancillary Services Net Revenue Variance - Nuclear		(13.6)	(15.1)	(13.5)	(10.0)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project		(47.6)	121.4	170.2	188.5
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP		49.7	146.5	173.7	160.2
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(30.9)	(25.8)	(16.8)	(10.0)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		79.4	83.3	70.1	40.1
25	Capacity Refurbishment Variance - Nuclear - PRP		0.0	0.0	0.0	(12.9)
26	Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved		84.2	63.2	42.1	21.1
27	Bruce Lease Net Revenues Variance - Post 2017 Additions		17.1	(4.2)	(102.0)	(191.1)
28	Income and Other Taxes Variance - Nuclear		(18.8)	(15.6)	(9.5)	(5.9)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		42.9	21.5	0.0	0.0
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(122.6)	(341.3)	(411.1)	(393.9)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		212.8	159.6	106.4	53.2
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		88.2	44.1	0.0	0.0
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved		222.5	166.9	111.3	55.6
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved		164.8	164.8	131.9	65.9
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(383.4)	(342.1)	(244.4)	(142.1)
36	Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	5	(12.3)	(26.9)	(42.1)	(58.4)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(74.7)	(76.5)	(61.5)	(102.1)
38	Fitness for Duty Deferral		1.6	2.0	2.5	3.4
39	SR&ED ITC Variance		(8.6)	(23.3)	(25.7)	(40.5)
40	Rate Smoothing Deferral		568.9	653.8	677.4	702.1
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		(57.5)	24.4	85.1	42.5
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		(45.0)	9.6	66.1	84.1
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		0.0	0.0	(2.3)	12.0
44	Pickering Closure Costs Deferral		2.8	6.4	7.6	8.7
45	Clarington Corporate Campus Deferral		0.0	7.3	7.7	7.9
46	Pickering B Variance	6	0.0	26.5	131.1	349.1
47	Nuclear Subtotal		1,019.1	1,322.3	1,466.8	1,409.9
48	Sale of Unprescribed Kipling Site Deferral		0.0	(15.1)	(12.6)	(7.5)
50	Total (line 16 + line 47 + line 48)	7	1,338.9	1,567.1	1,676.5	1,571.0

Notes:

1

From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.

2

From Ex. H1-1-1, Table 1a, col. (h).

3

From Ex. H1-1-1, Table 1b, col. (g).

4

From Ex. L-H1-Staff-260, Attachment 1, Table 1c, col. (g).

5

The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

6

Established by *Ontario Regulation 53/05*, effective January 1, 2023 and as amended effective July 1, 2025.

7

The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2025 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 1a

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2023 (\$M)

Line No.	Account	Note	Actual Year End Balance 2022	EB-2023-0336 Settlement Adjustments	(a)+(b) EB-2023-0336 Year-End Balance 2022	Actual 2023				(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2023
						Transactions	Amortization EB-2020-0290	Interest	Transfers	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Note 1	Note 2			Note 3	Note 4		
	Hydroelectric:									
1	Hydroelectric Water Conditions Variance		(172.4)	0.0	(172.4)	(41.3)	36.4	(8.3)	0.0	(185.6)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(34.3)	0.0	(34.3)	(6.7)	11.1	(1.6)	0.0	(31.5)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		401.8	0.0	401.8	29.7	(56.1)	17.9	0.0	393.3
5	Income and Other Taxes Variance - Hydroelectric		(13.3)	0.0	(13.3)	(4.2)	0.9	(0.7)	0.0	(17.3)
6	Capacity Refurbishment Variance - Hydroelectric	5	80.4	(4.7)	75.7	16.2	0.0	3.8	0.0	95.7
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.0	0.0	8.0	1.7	(1.3)	0.4	0.0	8.8
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		2.1	0.0	2.1	0.0	(1.1)	0.0	0.0	1.1
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		33.0	0.0	33.0	0.0	(8.3)	0.0	0.0	24.8
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		14.0	0.0	14.0	0.0	(7.0)	0.0	0.0	7.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		35.3	0.0	35.3	0.0	(8.8)	0.0	0.0	26.5
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		28.1	0.0	28.1	(19.7)	0.0	0.0	0.0	8.4
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(77.0)	0.0	(77.0)	(15.6)	12.9	(3.7)	0.0	(83.5)
14	Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	6	(2.0)	0.0	(2.0)	(2.9)	0.0	0.0	0.0	(4.9)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		16.1	0.0	16.1	1.6	(1.1)	0.7	0.0	17.3
16	Regulated Hydroelectric Subtotal		319.9	(4.7)	315.1	(41.2)	(22.4)	8.4	0.0	260.0
	Nuclear:									
17	Nuclear Liability Deferral	9	188.3	0.0	188.3	189.14	0.0	0.0	0.0	377.5
18	Nuclear Development Variance - DNNP		110.9	(0.1)	110.8	(8.1)	(1.2)	5.3	0.0	106.7
19	Nuclear Development Variance - Non-DNNP		0.0	0.0	0.0	7.6	0.0	0.2	0.0	7.8
20	Ancillary Services Net Revenue Variance - Nuclear		(13.6)	0.0	(13.6)	(2.0)	1.2	(0.7)	0.0	(15.1)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project	9	(47.6)	0.0	(47.6)	168.1	0.0	0.9	0.0	121.4
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP	9	49.7	(4.2)	45.6	64.2	32.0	4.6	0.0	146.5
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(30.9)	0.0	(30.9)	0.0	6.4	(1.3)	0.0	(25.8)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		79.4	0.0	79.4	0.0	(0.0)	3.9	0.0	83.3
25	Capacity Refurbishment Variance - Nuclear - PRP		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved		84.2	0.0	84.2	0.0	(21.1)	0.0	0.0	63.2
27	Bruce Lease Net Revenues Variance - Post 2017 Additions	9	17.1	0.0	17.1	(16.9)	(7.7)	3.3	0.0	(4.2)
28	Income and Other Taxes Variance - Nuclear		(18.8)	0.0	(18.8)	(1.0)	4.8	(0.7)	0.0	(15.6)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		42.9	0.0	42.9	0.0	(21.5)	0.0	0.0	21.5
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(122.6)	0.0	(122.6)	(218.7)	0.0	0.0	0.0	(341.3)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		212.8	0.0	212.8	0.0	(53.2)	0.0	0.0	159.6
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		88.2	0.0	88.2	0.0	(44.1)	0.0	0.0	44.1
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved		222.5	0.0	222.5	0.0	(55.6)	0.0	0.0	166.9
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved		164.8	0.0	164.8	0.0	0.0	0.0	0.0	164.8
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(383.4)	0.0	(383.4)	0.0	58.1	(16.8)	0.0	(342.1)
36	Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	6	(12.3)	0.0	(12.3)	(14.8)	0.2	0.0	0.0	(26.9)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(74.7)	-	(74.7)	(6.1)	8.4	(4.1)	-	(76.5)
38	Fitness for Duty Deferral	11	1.6	0.0	1.6	0.4	0.0	0.1	0.0	2.0
39	SR&ED ITC Variance		(8.6)	0.0	(8.6)	(18.0)	4.0	(0.7)	0.0	(23.3)
40	Rate Smoothing Deferral	10	568.9	0.0	568.9	64.0	0.0	20.9	0.0	653.8
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		(57.5)	0.0	(57.5)	0.0	81.9	0.0	0.0	24.4
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		(45.0)	0.0	(45.0)	54.6	0.0	0.0	0.0	9.6
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Pickering Closure Costs Deferral	12	2.8	0.0	2.8	3.4	0.0	0.2	0.0	6.4
45	Clarington Corporate Campus Deferral Account		0.0	0.0	0.0	7.0	0.0	0.3	0.0	7.3
46	Pickering B Variance		0.0	0.0	0.0	26.2	0.0	0.3	0.0	26.5
47	Nuclear Subtotal		1,019.1	(4.3)	1,014.8	299.1	(7.3)	15.7	0.0	1,322.3
48	Sale of Unprescribed Kipling Site Deferral	7	0.0	(12.7)	(12.7)	(2.5)	0.0	0.0	0.0	(15.1)
49	Total (line 16 + line 47 + line 48)	8	1,338.9	(21.7)	1,317.3	255.4	(29.7)	24.1	0.0	1,567.1

Notes:

1 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.

2 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (c1) for regulated hydroelectric and Table 2, col. (c1) for nuclear.

3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (i) for Regulated Hydroelectric, and App. D, Table 1, col. (i) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The year-end 2022 balance has been updated from that presented in EB-2023-0336 to reflect changes identified in the course of preparing this application.

6 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

7 The year-end 2022 balance has been updated from that presented in EB-2023-0336 pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5. Account transactions in 2023 recorded pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5, and represent 50% of the 23% of an incremental \$21.5M after-tax gain recognized by OPG in 2023 associated with the sale of the Kipling Site.

8 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

9 Includes the following adjustments, presented as part of 2023 transactions in col. (d): (i) reduction of \$4.1M in line 17 and addition of \$2.1M in line 26 to reflect the 2022 impact of updated calculations to the dollar per cubic metre cost rates for low and intermediate level waste ("L&ILW") based on the 2022 ONFA Reference Plan ("Reference Plan"); (ii) net addition of \$0.8M in line 21, reflecting the combined impact of \$1.4M reduction for updated calculations to the dollar per cubic metre cost rates for L&ILW in 2022 and \$2.2M addition to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application; and (iii) reduction of \$0.4M in line 22 to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application.

10 The year-end 2022 balance comprises deferral amounts recorded from 2017 to 2021 per EB-2016-0152 Payment Amounts Order, App. H, p. 1: 2017 - \$0M, 2018 - \$0M, 2019 - \$102.2M, 2020 - \$390.6M, 2021 - \$0M; deferral amount of \$19.0M recorded in 2022 per EB-2020-0290 Payment Amounts Order, App. B, Table 1; and interest on the account balance recorded at the following OPG long-term debt rates, compounded annually: 2019 - 4.52%, 2020 - 4.49%, 2021 - 4.48% (EB-2016-0152 Payment Amounts Order, App. H, p. 2) and 3.61% in 2022 (EB-2020-0290 Payment Amounts Order, App. E, p. 19). Transactions in 2023 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

11 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2017 - \$0.1M, 2018 - \$0.1M, 2019 - \$0.3M, 2020 - \$0.1M, 2021 - \$0.5M and 2022 - \$0.4M, plus interest on the account balance at the OEB's prescribed interest rate.

12 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2021 - \$1.0M and 2022 - \$1.8M, plus interest on the account balance at the OEB's prescribed interest.

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2024 (\$M)

Line No.	Account	Note	Actual Year End Balance 2023	Actual 2024					(a)+(b)+(c)+(d)+(e)+(f)
				Transactions	Amortization EB-2020-0290	Amortization EB-2023-0336	Interest	Transfers	Audited Year End Balance 2024
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1		Note 2	Note 3	Note 4		
	Hydroelectric:								
1	Hydroelectric Water Conditions Variance		(185.6)	(35.1)	36.4	19.9	(8.2)	0.0	(172.6)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(31.5)	(3.0)	11.1	2.4	(1.2)	0.0	(22.2)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		393.3	10.6	(56.1)	(57.9)	15.7	0.0	305.6
5	Income and Other Taxes Variance - Hydroelectric		(17.3)	(2.3)	0.9	2.3	(0.8)	0.0	(17.3)
6	Capacity Refurbishment Variance - Hydroelectric		95.7	72.0	0.0	(10.3)	4.7	0.0	162.1
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.8	1.7	(1.3)	(1.1)	0.4	0.0	8.6
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		1.1	0.0	(1.1)	0.0	0.0	0.0	0.0
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		24.8	0.0	(8.3)	0.0	0.0	0.0	16.5
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		7.0	0.0	(7.0)	0.0	0.0	0.0	0.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		26.5	0.0	(8.8)	0.0	0.0	0.0	17.7
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		8.4	(10.8)	0.0	(5.6)	0.0	0.0	(8.0)
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(83.5)	(12.1)	12.9	10.3	(3.8)	0.0	(76.3)
14	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	5	(4.9)	(4.0)	0.0	0.4	0.0	0.0	(8.5)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		17.3	2.6	(1.1)	(2.8)	0.7	0.0	16.7
16	Regulated Hydroelectric Subtotal		260.0	19.6	(22.4)	(42.5)	7.6	0.0	222.3
	Nuclear:								
17	Nuclear Liability Deferral		377.5	187.5	0.0	(37.7)	0.0	0.0	527.3
18	Nuclear Development Variance - DNNP		106.7	(26.5)	(1.2)	(21.7)	4.5	0.0	61.8
19	Nuclear Development Variance - Non-DNNP		7.8	15.1	0.0	0.0	0.6	0.0	23.5
20	Ancillary Services Net Revenue Variance - Nuclear		(15.1)	(1.1)	1.2	2.3	(0.7)	0.0	(13.5)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project		121.4	41.5	0.0	0.0	7.3	0.0	170.2
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP		146.5	9.3	32.0	(22.4)	8.3	0.0	173.7
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(25.8)	0.0	6.4	3.6	(1.0)	0.0	(16.8)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		83.3	0.0	(0.0)	(15.9)	2.8	0.0	70.1
25	Capacity Refurbishment Variance - Nuclear - PRP		0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved		63.2	0.0	(21.1)	0.0	0.0	0.0	42.1
27	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2017 Additions		(4.2)	(89.2)	(7.7)	(0.3)	(0.7)	0.0	(102.0)
28	Income and Other Taxes Variance - Nuclear		(15.6)	0.0	4.8	1.8	(0.5)	0.0	(9.5)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		21.5	0.0	(21.5)	0.0	0.0	0.0	0.0
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(341.3)	(94.4)	0.0	24.5	0.0	0.0	(411.1)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		159.6	0.0	(53.2)	0.0	0.0	0.0	106.4
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		44.1	0.0	(44.1)	0.0	0.0	0.0	0.0
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved		166.9	0.0	(55.6)	0.0	0.0	0.0	111.3
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336		164.8	0.0	0.0	(33.0)	0.0	0.0	131.9
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(342.1)	0.0	58.1	53.5	(13.8)	0.0	(244.4)
36	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	5	(26.9)	(17.8)	0.2	2.4	0.0	0.0	(42.1)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(76.5)	(1.2)	8.4	11.6	(3.7)	0.0	(61.5)
38	Fitness for Duty Deferral	8	2.0	0.4	0.0	0.0	0.1	0.0	2.5
39	SR&ED ITC Variance		(23.3)	(5.5)	4.0	0.1	(1.0)	0.0	(25.7)
40	Rate Smoothing Deferral	7	653.8	0.0	0.0	0.0	23.6	0.0	677.4
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		24.4	0.0	81.9	(21.3)	0.0	0.0	85.1
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		9.6	47.4	0.0	9.0	0.0	0.0	66.1
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		0.0	(2.3)	0.0	0.0	0.0	0.0	(2.3)
44	Pickering Closure Costs Deferral	8	6.4	0.9	0.0	0.0	0.3	0.0	7.6
45	Clarington Corporate Campus Deferral Account		7.3	0.0	0.0	0.0	0.4	0.0	7.7
46	Pickering B Variance		26.5	101.4	0.0	0.0	3.3	0.0	131.1
47	Nuclear Subtotal		1,322.3	165.4	(7.3)	(43.4)	29.9	0.0	1,466.8
48	Sale of Unprescribed Kipling Site Deferral		(15.1)	0.0	0.0	2.5	0.0	0.0	(12.6)
49	Total (line 16 + line 47 + line 48)	6	1,567.1	184.9	(29.7)	(83.3)	37.5	0.0	1,676.5

Notes:

1 From Ex. H1-1-1, Table 1a, col. (h).

2 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (j) for Regulated Hydroelectric and App. D, Table 1, col. (j) for Nuclear.

3 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (g) for Regulated Hydroelectric and Table 2, col. (g) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

6 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

7 Transactions in 2024 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

8 Account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements.

Table 1c
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2025 (\$M)

Line No.	Account	Note	Actual Year End Balance 2024	Actual 2025					(a)+(b)+(c)+(d)+(e)+(f)
				Transactions	Amortization EB-2020-0290	Amortization EB-2023-0336	Interest	Transfers	Actual Year End Balance 2025
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1		Note 2	Note 3	Note 4		
	Hydroelectric:								
1	Hydroelectric Water Conditions Variance		(172.6)	18.3	0.0	39.9	(4.5)	0.0	(118.9)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(22.2)	(42.4)	0.0	4.8	(0.9)	0.0	(60.7)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	0.0	(0.0)	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		305.6	18.5	0.0	(115.8)	6.1	0.0	214.3
5	Income and Other Taxes Variance - Hydroelectric		(17.3)	(2.3)	0.0	4.6	(0.4)	0.0	(15.5)
6	Capacity Refurbishment Variance - Hydroelectric	10	162.1	73.0	0.0	(20.7)	4.5	0.0	218.9
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.6	1.7	0.0	(2.2)	0.2	0.0	8.3
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		16.5	0.0	(8.3)	0.0	0.0	0.0	8.3
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		17.7	0.0	(8.8)	0.0	0.0	0.0	8.8
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		(8.0)	(6.1)	0.0	(11.2)	0.0	0.0	(25.4)
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(76.3)	(17.8)	0.0	20.5	(2.0)	0.0	(75.5)
14	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	5	(8.5)	(4.7)	0.0	0.8	0.0	0.0	(12.4)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		16.7	6.9	0.0	(5.5)	0.4	0.0	18.4
16	Regulated Hydroelectric Subtotal		222.3	45.0	(17.1)	(84.9)	3.3	0.0	168.6
	Nuclear:								
17	Nuclear Liability Deferral		527.3	2.2	0.0	(75.3)	0.0	0.0	454.1
18	Nuclear Development Variance - DNNP		61.8	44.8	0.0	(43.3)	0.7	0.0	63.9
19	Nuclear Development Variance - Non-DNNP		23.5	39.4	0.0	0.0	1.4	0.0	64.2
20	Ancillary Services Net Revenue Variance - Nuclear		(13.5)	(0.7)	0.0	4.5	(0.3)	0.0	(10.0)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project		170.2	13.1	0.0	0.0	5.2	0.0	188.5
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP		173.7	26.1	0.0	(44.7)	5.2	0.0	160.2
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(16.8)	0.0	0.0	7.2	(0.4)	0.0	(10.0)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		70.1	0.0	0.0	(31.7)	1.7	0.0	40.1
25	Capacity Refurbishment Variance - Nuclear - PRP		0.0	(12.7)	0.0	0.0	(0.2)	0.0	(12.9)
26	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved		42.1	0.0	(21.1)	0.0	0.0	0.0	21.1
27	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2017 Additions		(102.0)	(84.1)	0.0	(0.7)	(4.3)	0.0	(191.1)
28	Income and Other Taxes Variance - Nuclear		(9.5)	0.0	0.0	3.7	(0.1)	0.0	(5.9)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(411.1)	(31.8)	0.0	49.0	0.0	0.0	(393.9)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		106.4	0.0	(53.2)	0.0	0.0	0.0	53.2
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved		111.3	0.0	(55.6)	0.0	0.0	0.0	55.6
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved		131.9	0.0	0.0	(65.9)	0.0	0.0	65.9
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(244.4)	0.0	0.0	106.9	(4.6)	0.0	(142.1)
36	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	5	(42.1)	(21.0)	0.0	4.8	0.0	0.0	(58.4)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(61.5)	(61.3)	0.0	23.2	(2.5)	0.0	(102.1)
38	Fitness for Duty Deferral	8	2.5	0.8	0.0	0.0	0.1	0.0	3.4
39	SR&ED ITC Variance		(25.7)	(14.3)	0.0	0.2	(0.8)	0.0	(40.5)
40	Rate Smoothing Deferral	7	677.4	0.0	0.0	0.0	24.7	0.0	702.1
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		85.1	0.0	0.0	(42.5)	0.0	0.0	42.5
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		66.1	0.0	0.0	18.0	0.0	0.0	84.1
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		(2.3)	14.4	0.0	0.0	0.0	0.0	12.0
44	Pickering Closure Costs Deferral	8	7.6	0.8	0.0	0.0	0.2	0.0	8.7
45	Clarington Corporate Campus Deferral		7.7	0.0	0.0	0.0	0.2	0.0	7.9
46	Pickering B Variance	9	131.1	211.9	0.0	0.0	6.1	0.0	349.1
47	Nuclear Subtotal		1,466.8	127.5	(129.9)	(86.8)	32.3	0.0	1,409.9
48	Sale of Unprescribed Kipling Site Deferral		(12.6)	0.0	0.0	5.1	0.0	0.0	(7.5)
49	Total (line 16 + line 47 + line 48)	6	1,676.5	172.5	(147.0)	(166.6)	35.6	0.0	1,571.0

Notes:

1 From Ex. H1-1-1, Table 1b, col. (g).

2 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (k) for Regulated Hydroelectric and App. D, Table 1, col. (k) for Nuclear.

3 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (h) for Regulated Hydroelectric and Table 2, col. (h) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

6 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2025 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

7 Transactions in 2025 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

8 Account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements.

9 Includes a reduction for \$1.0M, presented as part of 2025 transactions in col. (b), to correct minor discrepancies identified for years prior to 2025 in the course of preparing this interrogatory response.

10 Includes a reduction for \$4.0M, presented as part of 2025 transactions in col. (b), to correct minor discrepancies identified for years prior to 2025 in the course of preparing this interrogatory response.

Numbers may not add due to rounding.

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Exhibit L

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Attachment 1

Table 2

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	<u>Regulated Hydroelectric:</u>				
1	Forecast Production (GWh)	1	32,432	32,432	32,432
2	Actual Calculated Production (GWh)		33,898	33,650	32,021
3	Difference (GWh) (line 1 - line 2)		(1,466)	(1,218)	411
4	Payment Amount (\$/MWh)	2	43.88	43.88	43.88
5	Revenue Impact (\$M) (line 3 x line 4 / 1000)		(64.3)	(53.5)	18.0
6	GRC/Water Rental Costs (\$M)		23.1	18.4	0.3
7	Total Addition to Variance Account (\$M) (line 5 + line 6)		(41.3)	(35.1)	18.3

Notes:

- 1 Cols. (a), (b) and (c) as set out in EB-2020-0290 Payment Amounts Order, App. E, pp. 3-4.
- 2 Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, p. 4.

Numbers may not add due to rounding.

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Attachment 1
Table 3

Table 3
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	<u>Regulated Hydroelectric:</u>				
1	Forecast Revenue	1	55.5	55.5	55.5
2	Actual Revenue	2	62.3	58.5	98.0
3	Regulated Hydroelectric Addition to Variance Account (line 1 - line 2)		(6.7)	(3.0)	(42.4)
	<u>Nuclear:</u>				
4	Forecast Revenue	1	6.3	6.1	6.5
5	Actual Revenue	2	8.3	7.3	7.1
6	Nuclear Addition to Variance Account (line 4 - line 5)		(2.0)	(1.1)	(0.7)

Notes:

- 1 Cols. (a), (b) and (c) as per EB-2020-0290 Payment Amounts Order, App. E, pp. 4-5.
- 2 Cols. (a) and (b) as shown in Ex. G1-1-1, Table 1, line 1, cols. (h) and (i) for regulated hydroelectric.
Cols. (a) and (b) as shown in Ex. G2-1-1, Table 1, line 6, cols. (d) and (e) for nuclear.
Col. (c) as shown in Ex. L-A1-CCC-001, Att. 1, Table 65, line 1, col. (j) for regulated hydroelectric.
Col. (c) as shown in Ex. L-A1-CCC-001, Att. 1, Table 66, line 6, col. (f) for nuclear.

Numbers may not add due to rounding.

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Attachment 1
Table 4

Table 4
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1	Total Actual Regulated Hydroelectric Incentive Mechanism Net Revenue	1	14.8	28.4	52.9
2	Threshold	2	54.5	54.5	54.5
3	Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold (line 1 - line 2; nil if line 1 < line 2)		0.0	0.0	0.0
4	Percentage	2	50%	50%	50%
5	Total Addition to Variance Account (line 3 x line 4)		0.0	0.0	0.0

Notes:

- 1 Annual values as reported in OPG's 2024 Management's Discussion & Analysis (p. 51) for 2023 and 2024, and 2025 Management's Discussion & Analysis (p. 42) for 2025.
- 2 Annual threshold and percentage per EB-2014-0370 Payment Amounts Order, App. B, pp. 8-9.

Numbers may not add due to rounding.

Filed: 2026-04-24

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Exhibit L

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Attachment 1

Table 5

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	<u>Regulated Hydroelectric:</u>				
1	Actual Foregone Production Due to SBG Conditions (GWh)	1	977	350	751
2	Payment Amount (\$/MWh)	2	43.88	43.88	43.88
3	Revenue (\$M) (line 1 x line 2 / 1000)		42.9	15.3	33.0
4	GRC/Water Rental Costs (\$M)		(13.2)	(4.7)	(9.7)
5	Market Renewal Credit	3	0.0	0.0	(4.8)
6	Total Addition to Variance Account (\$M) (line 3 + line 4 + line 5)		29.7	10.6	18.5

Notes:

- 1 Total annual SBG in cols. (a) and (b) is as reported in OPG's 2024 Management's Discussion & Analysis (p.14). Col. (c) is as reported in OPG's 2025 Management's Discussion & Analysis (p.13).
- 2 Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, p.4.
- 3 Per EB-2023-0336 Decision and Order, p.4.

Table 6
Income and Other Taxes Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023			Actual 2024			Actual 2025		
			Regulated Hydroelectric	Nuclear	(a) + (b) Total	Regulated Hydroelectric	Nuclear	(d) + (e) Total	Regulated Hydroelectric	Nuclear	(g) + (h) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Entry (i): CCA Accelerated Investment Incentive Property Impact	1									
1	2023 CCA differences		(11.2)	0.0	(11.2)	0.0	0.0	0.0	0.0	0.0	0.0
2	2024 CCA differences		0.0	0.0	0.0	(6.4)	0.0	(6.4)	0.0	0.0	0.0
3	2025 CCA differences		0.0	0.0	0.0	0.0	0.0	0.0	(6.4)	0.0	(6.4)
4	Income Tax Impact for 2023 (line 1 x 25%)		(2.8)	0.0	(2.8)	0.0	0.0	0.0	0.0	0.0	0.0
5	Income Tax Impact for 2024 (line 2 x 25%)		0.0	0.0	0.0	(1.6)	0.0	(1.6)	0.0	0.0	0.0
6	Income Tax Impact for 2025 (line 3 x 25%)		0.0	0.0	0.0	0.0	0.0	0.0	(1.6)	0.0	(1.6)
7	Addition to Variance Account (line 4 + line 5 + line 6) / (1-25%)		(3.7)	0.0	(3.7)	(2.1)	0.0	(2.1)	(2.1)	0.0	(2.1)
	Entry (ii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017	2									
8	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		(0.7)	(2.9)	(3.7)	0.0	0.0	0.0	0.0	0.0	0.0
9	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 8 x 4/3)		(1.0)	(3.9)	(4.9)	0.0	0.0	0.0	0.0	0.0	0.0
10	Addition to Variance Account (line 9 - line 8)		(0.2)	(1.0)	(1.2)	0.0	0.0	0.0	0.0	0.0	0.0
	Entry (iii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	3									
11	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		(0.7)	0.0	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0
12	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 11 x 4/3)		(1.0)	0.0	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0
13	Addition to Variance Account (line 12 - line 11)		(0.2)	0.0	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0
	Entry (iv) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	4									
14	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		0.0	0.0	0.0	(0.7)	0.0	(0.7)	0.0	0.0	0.0
15	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 14 x 4/3)		0.0	0.0	0.0	(1.0)	0.0	(1.0)	0.0	0.0	0.0
16	Addition to Variance Account (line 15 - line 14)		0.0	0.0	0.0	(0.2)	0.0	(0.2)	0.0	0.0	0.0
	Entry (v) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2025 for 2020	5									
17	Forecast SR&ED ITCs, net of Tax on ITCs, at 75%		0.0	0.0	0.0	0.0	0.0	0.0	(0.7)	0.0	(0.7)
18	Forecast SR&ED ITCs, net of Tax on ITCs, at 100% (line 17 x 4/3)		0.0	0.0	0.0	0.0	0.0	0.0	(1.0)	0.0	(1.0)
19	Addition to Variance Account (line 18 - line 17)		0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	0.0	(0.2)
	Entry (vi): Ontario Research and Development Tax Credit (ORDTC) Reduction from 4.5% to 3.5% Effective June 1, 2016										
20	Addition to Variance Account - Reduction in ORDTC Rate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Total Addition to Variance Account (line 7 + line 10 + line 13 + line 16 + line 19 + line 20)		(4.2)	(1.0)	(5.2)	(2.3)	0.0	(2.3)	(2.3)	0.0	(2.3)

Notes:

1

Recorded to reflect the impact of changes in Capital Cost Allowance (CCA) rules, whereby taxpayers can claim higher first-year CCA deductions on eligible capital assets acquired after November 20, 2018, for assets other than those subject to the Capacity Refurbishment Variance Account (CRVA) and the Nuclear Development Variance Account (NDVA). The impact of this rule change for assets subject to the CRVA and NDVA are recorded in the respective accounts as part of the total CCA variances for eligible projects. No entries have been recorded for the nuclear facilities beginning January 1, 2022 as the impact of this rule change was reflected in the EB-2020-0290 nuclear revenue requirements.

2

Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount at line 9 represents SR&ED ITCs, net of tax on ITCs, for 2017 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. For the nuclear facilities, the amount at line 7 represents the January 1 to May 31, 2017 portion of said credit. The June 1 to December 31, 2017 portion for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

3

Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount at line 12 represents SR&ED ITCs, net of tax on ITCs, for 2018 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

4

Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount at line 15 represents SR&ED ITCs, net of tax on ITCs, for 2019 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

5

Recorded in 2025 following the resolution, during 2025, of the 2020 taxation year audit. Amount at line 18 represents SR&ED ITCs, net of tax on ITCs, for 2020 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
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Attachment 1
Table 7

Table 7
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023			Actual 2024			Actual 2025		
			Regulated Hydroelectric	Nuclear ⁴	(a)+(b) Total	Regulated Hydroelectric	Nuclear ⁴	(d)+(e) Total	Regulated Hydroelectric	Nuclear ⁴	(g)+(h) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Forecast Pension Contributions	1	45.1	0.0	45.1	45.1	0.0	45.1	45.1	0.0	45.1
2	Forecast OPEB Payments	1	12.8	0.0	12.8	12.8	0.0	12.8	12.8	0.0	12.8
3	Total Forecast Pension and OPEB Cash Amounts (line 1 + line 2)		58.0	0.0	58.0	58.0	0.0	58.0	58.0	0.0	58.0
4	Actual Pension Contributions	2	23.1	0.0	23.1	27.6	0.0	27.6	20.1	0.0	20.1
5	Actual OPEB Payments	2	19.2	0.0	19.2	18.2	0.0	18.2	20.1	0.0	20.1
6	Total Actual Pension and OPEB Cash Amounts (line 4 + line 5)		42.3	0.0	42.3	45.8	0.0	45.8	40.2	0.0	40.2
7	Total Addition to Pension & OPEB Cash Payment Variance Account (line 6 - line 3)		(15.6)	0.0	(15.6)	(12.1)	0.0	(12.1)	(17.8)	0.0	(17.8)
8	Actual Pension - Registered Pension Plan (RPP) Accrual Costs	3	(5.0)	0.0	(5.0)	8.1	0.0	8.1	(2.0)	0.0	(2.0)
9	Actual OPEB - Non-RPP Accrual Costs	3	27.7	0.0	27.7	27.0	0.0	27.0	36.1	0.0	36.1
10	Total Actual Pension and OPEB Accrual (line 8 + line 9)		22.6	0.0	22.6	35.1	0.0	35.1	34.0	0.0	34.0
11	Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - RPP (line 8 - line 4)		(28.1)	0.0	(28.1)	(19.6)	0.0	(19.6)	(22.1)	0.0	(22.1)
12	Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - Non-RPP (line 9 - line 5)		8.4	0.0	8.4	8.8	0.0	8.8	16.0	0.0	16.0
13	Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account (line 11 + line 12)		(19.7)	0.0	(19.7)	(10.8)	0.0	(10.8)	(6.1)	0.0	(6.1)

Notes:

- 1 Cols. (a), (d) and (g) are per EB-2020-0290 Payment Amounts Order, App. E, p. 12.
- 2 Represents the portion of OPG's actual pension contributions and OPEB payments for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp.9-10 for 2023 and 2024, attributed to the regulated hydroelectric facilities.
- 3 Represents the portion of OPG's actual pension and OPEB costs for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10 for 2023 and 2024, attributed to the regulated hydroelectric facilities.
- 4 As per the EB-2020-0290 Payment Amounts Order, App. E, p. 12, no additions are recorded to the Pension & OPEB Cash Payment Variance Account or the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the nuclear facilities beginning in 2022 as the nuclear revenue requirements approved in that proceeding reflected pension and OPEB costs calculated on an accrual basis.

Numbers may not add due to rounding.

Filed: 2026-04-24
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Attachment 1
Table 7a

Table 7a
Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account - Primary, Contra and Carrying Charges Sub-Accounts
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023			Actual 2024			Actual 2025		
			Regulated Hydroelectric	Nuclear	(a)+(b) Total	Regulated Hydroelectric	Nuclear	(d)+(e) Total	Regulated Hydroelectric	Nuclear	(g)+(h) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Registered Pension Plan (RPP) - EB-2018-0243 Approved	1	8.3	53.2	61.5	8.3	53.2	61.5	8.3	53.2	61.5
2	Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Non-RPP - EB-2018-0243 Approved	1	7.0	44.1	51.1	7.0	44.1	51.1	0.0	0.0	0.0
3	Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2017 Additions - EB-2020-0290 Approved	1	8.8	55.6	64.5	8.8	55.6	64.5	8.8	55.6	64.5
4	Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2019 Additions	2	0.0	0.0	0.0	5.6	33.0	38.6	11.2	65.9	77.2
5	Actual Pension and OPEB Accrual Costs - Nuclear	3	0.0	125.6	125.6	0.0	205.2	205.2	0.0	199.4	199.4
6	Actual Pension and OPEB Cash Amounts - Nuclear	4	0.0	234.9	234.9	0.0	268.2	268.2	0.0	235.4	235.4
7	Total Addition to Primary Sub-Account Tracking Balance (line 1 + line 2 + line 3 + line 4 + line 5 - line 6)		24.1	43.6	67.6	29.7	122.8	152.5	28.3	138.8	167.1
8	Total Addition to Contra Sub-Account Tracking Balance (line 7 x -1)		(24.1)	(43.6)	(67.6)	(29.7)	(122.8)	(152.5)	(28.3)	(138.8)	(167.1)
9	Net Total Addition to Primary and Contra Sub-Accounts Tracking Balances		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Primary Sub-Account Tracking Credit Balance - Opening	5	45.0	267.4	312.4	69.1	310.9	380.0	98.7	433.8	532.5
11	Primary Sub-Account Tracking Credit Balance - Closing (line 7 + line 10)		69.1	310.9	380.0	98.7	433.8	532.5	127.1	572.5	699.6
12	Total Addition to Carrying Charges Sub-Account	6	(2.9)	(14.8)	(17.6)	(4.0)	(17.8)	(21.9)	(4.7)	(21.0)	(25.8)

Notes:

1 Cols. (a), (d), and (g) per EB-2020-0290 Payment Amounts Order, App. C, Table 1, lines 10-12, cols. (i), (j) and (k), respectively. Cols. (b), (e) and (h) per EB-2020-0290 Payment Amounts Order, App. D, Table 1, lines 15-17, cols. (i), (j) and (k), respectively.

2 Cols. (d) and (g) per EB-2023-0336 Decision and Order, App. A, Table 1, line 12, cols. (g) and (h), respectively. Cols. (e) and (h) per EB-2023-0336 Decision and Order, App. A, Table 2, line 16, cols. (g) and (h), respectively.

3 Cols. (b) and (e) from Ex. H1-1-1, Table 7b, line 6, cols. (a) and (b), respectively. Col. (h) from Ex. L-H1-Staff-260, Attachment 1, Table 7b, line 6, col. (c).

4 Cols. (b) and (e) represents the portion of OPG's actual pension contributions and OPEB payments for 2023 and 2024 respectively, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

5 Cols. (a) and (b) from EB-2023-0336, Ex. H1-1-1, Table 8a, line 10, cols. (g) and (h), respectively. Cols. (d), (e), (g) and (h) are equal to line 11 of the preceding year.

6 Carrying charges are calculated on the monthly opening cumulative balance in the Primary Sub-Account (when in a credit position) using the OEB's prescribed Construction Work in Progress rate, as follows: 2023 - 5.01% for Q1 to Q3 and 5.48% for Q4; 2024 - 5.48% for Q1, 4.98% for Q2 to Q3 and 4.55% for Q4; 2025 - 4.23%.

Table 7b
Pension and OPEB Cost Variance Account - Nuclear
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1	Forecast Accrual Pension Costs	1	134.3	111.7	71.3
2	Forecast Accrual OPEB Costs	1	159.9	161.0	156.9
3	Total Forecast Accrual Pension and OPEB Costs (line 1 + line 2)	2	294.1	272.7	228.2
4	Actual Accrual Pension Costs	3	(27.9)	47.2	(12.0)
5	Actual Accrual OPEB Costs	3	153.5	158.0	211.3
6	Total Actual Accrual Pension and OPEB Costs (line 4 + line 5)		125.6	205.2	199.4
7	Addition to Variance Account - Pension Costs (line 4 - line 1)		(162.2)	(64.5)	(83.3)
8	Addition to Variance Account - OPEB Costs (line 5 - line 2)		(6.3)	(3.0)	54.4
9	Addition to Variance Account - Income Tax Impact	4	(50.2)	(26.8)	(2.9)
10	Total Addition to Variance Account (line 7 + line 8 + line 9)		(218.7)	(94.4)	(31.8)

Notes:

- 1 From EB-2020-0290, Ex. F4-3-2, Chart 1.
- 2 From EB-2020-0290 Payment Amounts Order, App. E, p.10, line 27.
- 3 Represents the portion of OPG's actual pension and OPEB costs, for 2023 and 2024 as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.
- 4 Table to Note 4 - The income tax impact of the pension and OPEB cost additions to the account is calculated as follows (\$M):

Line No.		Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1a	Forecast Income Tax Impact	*	13.7	5.8	(9.1)
	Actual Additions to / Deductions from Regulatory Earnings Before Tax:				
2a	Actual Accrual Pension Costs (line 4)		(27.9)	47.2	(12.0)
3a	Actual Accrual OPEB Costs (line 5)		153.5	158.0	211.3
4a	Less: Actual Pension Contributions	**	128.2	161.7	117.6
5a	Less: Actual OPEB Payments	**	106.8	106.5	117.7
6a	Net Additions to Regulatory Earnings Before Tax (line 2a + line 3a - line 4a - line 5a)		(109.3)	(63.0)	(36.0)
7a	Actual Income Tax Impact (line 6a x 25% / (1 - 25%))		(36.4)	(21.0)	(12.0)
8a	Addition to Variance Account - Income Tax Impact (line 7a - line 1a)		(50.2)	(26.8)	(2.9)

- * From EB-2020-0290 Payment Amounts Order, App. E, p. 11, line 2.
- ** Represents the portion of OPG's actual pension contributions and OPEB payments, for 2023 and 2024 as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

Numbers may not add due to rounding.

Filed: 2026-04-24
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Exhibit L
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Attachment 1
Table 8

Table 8
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1	Regulated Hydroelectric Rider (\$/MWh)-EB-2020-0290	1	1.03	1.03	0.69
2	Regulated Hydroelectric Rider (\$/MWh)-EB-2023-0336	2		2.61	2.61
3	Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2020-0290	3	33.0	33.0	33.0
4	Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2023-0336	4		16.5	33.0
5	Regulated Hydroelectric Actual Production (TWh) - EB-2020-0290	5	31.4	32.5	30.9
6	Regulated Hydroelectric Actual Production (TWh) - EB-2023-0336	6		15.7	30.9
7	Production Variance for Regulated Hydroelectric Rider (TWh) EB-2020-0290 (line 3 - line 5)		1.6	0.5	2.1
8	Production Variance for Regulated Hydroelectric Rider (TWh) EB-2023-0336 (line 4 - line 6)			0.8	2.1
9	Addition to Variance Account (\$M) - Regulated Hydroelectric Rider-EB-2020-0290 (line 7 x line 1)		1.6	0.5	1.4
10	Addition to Variance Account (\$M) - Regulated Hydroelectric Rider-EB-2023-0336 (line 8 x line 2)			2.1	5.5
11	Addition to Variance Account (\$M) (line 9 + line 10)		1.6	2.6	6.9

Notes:

- 1 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 23, cols. (i), (j) and (k).
- 2 From EB-2023-0336 Decision and Order, App. A, Table 1, line 21, cols. (g) and (h).
- 3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 22, cols. (i), (j) and (k).
- 4 From EB-2023-0336 Decision and Order, App. A, Table 1, line 20, cols. (g) and (h).
- 5 Cols. (a) and (b) from Ex. E1-1-1, Table 1, line 4, cols. (h) and (i). Col. (c) from Ex. L-A1-CCC-001, Attachment 1, Table 27, line 4, col. (j).
- 6 Regulated hydroelectric actual production in col. (b) is for six months beginning July 1, 2024.

Table 9
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	Capital Addition to Variance Account:				
1	Actual Net Plant Rate Base Amount	1	19.3	19.0	18.8
2	Weighted Average Cost of Capital	2	6.85%	6.85%	6.85%
3	Actual Cost of Capital Amount (line 1 x line 2)		1.3	1.3	1.3
4	Cost of Capital Variance		1.3	1.3	1.3
5	Forecast Depreciation		0.0	0.0	0.0
6	Actual Depreciation		0.2	0.2	0.2
7	Depreciation Variance (line 6 - line 5)		0.2	0.2	0.2
	Income Tax Impact:				
8	Forecast Capital Cost Allowance Deduction		0.0	0.0	0.0
9	Actual Capital Cost Allowance Deduction		0.6	0.6	0.6
10	Difference (line 8 - line 9)		(0.6)	(0.6)	(0.6)
11	Net Increase in Regulatory Taxable Income	3	0.4	0.5	0.5
12	Income Tax Rate	4	25%	25%	25%
13	Income Tax Impact (line 11 x line 12 / (1 - line 12))		0.1	0.2	0.2
14	Total Addition to Variance Account (line 4 + line 7 + line 13)		1.7	1.7	1.7

Notes:

1The continuity of the variation between the original Niagara Tunnel Project rate base disallowance of \$28M and the varied disallowance of \$6.4M is as follows:

	Table to Note 1 - Niagara Tunnel Project Disallowance Continuity (\$M)			
Line No.		2023	2024	2025
		(a)	(b)	(c)
1a	Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 10, line 4a, col. (c))	19.4	19.1	18.9
2a	In-Service	0.0	0.0	0.0
3a	Depreciation Expense (line 6)	(0.2)	(0.2)	(0.2)
4a	Closing Balance	19.1	18.9	18.7
5a	Actual Net Plant Rate Base Amount (lines 1a+ 4a)/ 2	19.3	19.0	18.8

2From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).

3The change in regulatory taxable income is calculated as the sum of lines 7 and 10, plus the ROE component of the cost of capital variance at line 4. The ROE component of the variance is equal to line 1 multiplied by the OEB-approved equity portion (45%) of the capital structure, multiplied by the EB-2013-0321 OEB-approved ROE rate of 9.30%.

4From EB-2013-0321 Payment Amounts Order, App. A, Table 8, line 31, col. (c).

Numbers may not add due to rounding.

Filed: 2026-04-24
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Exhibit L
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Attachment 1
Table 10

Table 10
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1	Actual Total Bruce Lease Net Revenues (\$M)	1	(25.8)	42.5	27.2
2	Forecast Bruce Lease Net Revenue	2	(38.7)	(48.1)	(46.5)
3	Forecast Nuclear Production (TWh)	3	31.2	34.0	31.1
4	Rate Credited to (Recovered from) Customers (\$/MWh) (line 2 / line 3)	4	(1.24)	(1.42)	(1.50)
5	Actual Nuclear Production (TWh)	5	36.1	33.0	38.1
6	Amount Credited to (Recovered from) Customers (\$M) (line 4 x line 5)		(44.8)	(46.7)	(56.9)
7	Total Addition to Variance Account (\$M) (line 6 - line 1)		(19.0)	(89.2)	(84.1)

Notes:

- 1 Cols. (a) and (b) from Ex. G2-2-1, Table 1, line 3, cols. (d) and (e), respectively. Col. (c) from Ex. L-A1-CCC-001, Attachment 1, Table 67, line 3, col. (f).
- 2 Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
- 3 Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 2, cols. (b), (c) and (d), respectively.
- 4 Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
- 5 Cols. (a) and (b) from Ex. E2-1-1, Table 1, line 3, cols. (d) and (e), respectively. Col. (b) from Ex. L-A1-CCC-001, Attachment 1, Table 29, line 3, col. (f).

Numbers may not add due to rounding.

Filed: 2026-04-24
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Attachment 1
Table 11

Table 11
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
1	Nuclear Rider (\$/MWh)-EB-2020-0290	1	1.25	1.15	5.34
2	Nuclear Rider (\$/MWh)-EB-2023-0336	2		3.13	3.42
3	Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2020-0290	3	31.2	34.0	31.1
4	Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2023-0336	4		17.0	31.1
5	Actual Nuclear Production (TWh) - EB-2020-0290	5	36.1	33.0	38.1
6	Actual Nuclear Production (TWh) - EB-2023-0336	6		17.7	38.1
7	Production Variance for Nuclear Rider (TWh) EB 2020-0290 (line 3 - line 5)		(4.9)	1.03	(7.0)
8	Production Variance for Nuclear Rider (TWh) EB 2023-0336 (line 4 - line 6)			(0.8)	(7.0)
9	Addition To Variance Account - Nuclear Rider-EB-2020-0290 (line 7 x line 1)		(6.1)	1.2	(37.4)
10	Addition To Variance Account - Nuclear Rider-EB-2023-0336 (line 8 x line 2)			(2.4)	(23.9)
11	Addition To Variance Account (line 9 + line 10)		(6.1)	(1.2)	(61.3)

Notes:

- 1 From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 32, cols. (i), (j) and (k).
- 2 From EB-2023-0336 Decision and Order, App. A, Table 2, line 31, cols. (g) and (h)
- 3 From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 31, cols. (i), (j) and (k).
- 4 From EB-2023-0336 Decision and Order, App. A, Table 2, line 30, cols. (g) and (h).
- 5 Cols. (a) and (b) from Ex. E2-1-1, Table 1, line 3, cols. (d) and (e), respectively. Col. (c) from Ex. L-A1-CCC-001, Attachment 1, Table 29, line 3, col. (f).
- 6 Nuclear actual production in col. (b) is for six months beginning July 1, 2024.

Table 12
SR&ED ITCs Variance Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	Entry (i): Additions Based on Current Year Tax Provision				
1	Forecast Annual SR&ED ITCs	1	16.3	16.4	16.1
2	Less: Tax on Provincial Portion Taxable in Current Year		(0.8)	(0.8)	(0.8)
3	Less: Tax on Federal ITC in Prior Year		(3.3)	(3.3)	(3.3)
4	Forecast Annual SR&ED ITCs, net of Tax		12.2	12.3	12.0
5	Actual Annual SR&ED ITCs Recorded in the Year		19.7	15.0	16.6
6	Less: Tax on Provincial Portion Taxable in Current Year		(1.0)	(0.7)	(0.8)
7	Less: Tax on Federal ITC in Prior Year		(4.0)	(4.4)	(4.4)
8	Actual Annual SR&ED ITCs Recorded, net of Tax		14.8	9.9	11.4
9	Addition to Variance Account based on Current Year Tax Provision ((line 4 - line 8) / (1-25%))		(3.4)	3.2	0.8
	Entry (ii): True Up Adjustments Based on Prior Year's Income Tax Return				
10	Actual Annual SR&ED ITCs Recorded, net of Tax	2	13.5	14.8	9.9
11	Prior Year Actual Annual SR&ED ITCs per Income Tax Return Completed in Current Year		19.7	21.6	21.8
12	Less: Tax on Provincial Portion Taxable in Current Year		(1.0)	(1.1)	(1.1)
13	Less: Tax on Federal ITC in Prior Year		(4.1)	(4.0)	(4.4)
14	Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of Tax		14.7	16.6	16.4
15	True-Up Adjustment Based on Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of tax (line 10 - line 14)	3	(1.2)	(1.8)	(6.5)
16	Addition to Variance Account based on True-Up Adjustments based on Prior Year's Income Tax Return (line 15 / (1-25%))		(1.6)	(2.4)	(8.7)
	Entry (iii): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017 from June 1 to December 31, 2017	4			
17	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%		(12.1)	0.0	0.0
18	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100% (line 17 x 4/3)		(16.2)	0.0	0.0
19	Addition to Variance Account ((line 18 - line 17) / (1-25%))		(5.4)	0.0	0.0
	Entry (iv): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	5			
20	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%		(16.9)	0.0	0.0
21	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100% (line 20 x 4/3)		(22.6)	0.0	0.0
22	Addition to Variance Account ((line 21 - line 20) / (1-25%))		(7.5)	0.0	0.0
	Entry (v): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	6			
23	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%		0.0	(14.2)	0.0
24	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100% (line 23 x 4/3)		0.0	(18.9)	0.0
25	Addition to Variance Account ((line 24 - line 23) / (1-25%))		0.0	(6.3)	0.0
	Entry (vi): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2025 for 2020	7			
26	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%		0.0	0.0	(14.3)
27	Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100% (line 26 x 4/3)		0.0	0.0	(19.1)
28	Addition to Variance Account ((line 27 - line 26) / (1-25%))		0.0	0.0	(6.4)
29	Total Addition to Variance Account (line 9 + line 16 + line 19 + line 22+ line 25+ line 28)		(18.0)	(5.5)	(14.3)

Notes:

- 1 Cols. (a), (b) and (c) per EB-2020-0290 Payment Amounts Order, App. E, p. 18.
- 2 Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 14, line 8, col (c). Col. (b) from line 8, col. (a). Col. (c) from line 8, col. (b).
- 3 Represents the adjustment based on the final ITC values determined in 2023, 2024 and 2025 as part of the filing of the 2022, 2023 and 2024 income tax returns and trued up as part of the 2023, 2024 and 2025 entries to the variance account, respectively.
- 4 Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount in line 17 represents the June 1 to December 31, 2017 portion of SR&ED ITCs, net of tax on ITCs, for the nuclear facilities for 2017 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., 7/12 x EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (a)) . The SR&ED ITC Variance Account became effective on June 1, 2017.
- 5 Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount in line 20 represents the SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2018 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (b)).
- 6 Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount in line 23 represents actual SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2019 previously credited to ratepayers at 75% through EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB 2023-0336, Ex. H1-1-1, Table 14, line 11, col. (a)).
- 7 Recorded in 2025 following the resolution, during 2025, of the 2020 taxation year audit. Amount in line 26 represents actual SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2020 previously credited to ratepayers at 75% through EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB 2023-0336, Ex. H1-1-1, Table 14, line 11, col. (b)).

Table 13
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - Non-DRP/Non-PRP
Summary of Account Transactions 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	Non-Capital Addition to Variance Account - Non-DRP				
	Forecast Non-Capital Costs:				
1	Pickering Extended Operations	1	0.0	0.0	0.0
2	Fuel Channel Life Extension Project	1	0.0	0.0	0.0
3	FCLE Related Ongoing Costs	1	18.7	1.1	0.4
4	Darlington U3 Fuel Channel Component Retrieval Project	1	0.0	0.0	0.0
5	Darlington Annulus Spacer Life Management Project		0.0	0.0	0.0
6	Pickering B Refurbishment Feasibility Assessment		0.0	0.0	0.0
7	Darlington Steam Generator Primary Moisture Separators Replacement		0.0	0.0	0.0
8	Optimization of Pickering Shutdown	1	4.9	18.4	0.0
9	Fuel Channel Life Management Phase V Project		0.0	0.0	0.0
10	Total (lines 1 through 9)	2	23.6	19.4	0.4
	Actual Non-Capital Costs:	3			
11	Pickering Extended Operations		0.4	0.0	0.0
12	Fuel Channel Life Extension Project		3.0	(0.1)	0.0
13	FCLE Related Ongoing Costs		46.8	1.9	0.3
14	Darlington U3 Fuel Channel Component Retrieval Project		0.1	0.0	0.0
15	Darlington Annulus Spacer Life Management Project		0.4	0.0	0.0
16	Pickering B Refurbishment Feasibility Assessment		17.8	0.0	0.0
17	Darlington Steam Generator Primary Moisture Separators Replacement		4.5	3.8	0.0
18	Optimization of Pickering Shutdown		11.6	15.0	1.4
19	Fuel Channel Life Management Phase V Project		1.1	5.3	6.3
20	Total (lines 11 through 19)		85.7	25.9	7.9
	Non-Capital Addition to Variance Account:				
21	Pickering Extended Operations (line 11 - line 1)		0.4	0.0	0.0
22	Fuel Channel Life Extension Project (line 12 - line 2)		3.0	(0.1)	0.0
23	FCLE Related Ongoing Costs (line 13 - line 3)		28.0	0.8	(0.2)
24	Darlington U3 Fuel Channel Component Retrieval Project (line 14 - line 4)		0.1	0.0	0.0
25	Darlington Annulus Spacer Life Management Project (line 15 - line 5)		0.4	0.0	0.0
26	Pickering B Refurbishment Feasibility Assessment (line 16 - line 6)		17.8	0.0	0.0
27	Darlington Steam Generator Primary Moisture Separators (line 17 - line 7)		4.5	3.8	0.0
28	Optimization of Pickering Shutdown (line 18 - line 8)		6.7	(3.4)	1.4
29	Fuel Channel Life Management Phase V Project (line 19 - line 9)		1.1	5.3	6.3
30	Non-Capital Addition to Variance Account (lines 21 through 29)		62.1	6.5	7.4

Notes:

1

Cols. (a), (b) and (c) from EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 1.

2

Cols. (a), (b) and (c) from EB-2020-0290 Payment Amounts Order, App. E, p. 9.

3

Details for 2023 and 2024 actual non-capital costs from Ex. F2-1-1, Table 1a, F2-2-1, Table 1a, F2-3-1, Table 1, and Ex. F2-4-1, Table 1.
Details for 2025 actual non-capital costs from Ex. L-A1-CCC-001, Attachment 1, Tables 40, 42 and 43.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 14

Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP/Non-PRP
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	<u>Capital Addition to Variance Account:</u>				
1	Forecast Cost of Capital Amount	1	0.8	0.3	0.1
2	Actual Net Plant Rate Base Amount	2	68.5	151.5	230.7
3	Weighted Average Cost of Capital	1	5.83%	5.90%	5.92%
4	Actual Cost of Capital Amount (line 2 x 3)		4.0	8.9	13.7
5	Cost of Capital Variance (line 4 - line 1)		3.2	8.6	13.6
6	Forecast Depreciation	1	8.8	8.8	0.2
7	Actual Depreciation	2	11.5	9.9	9.6
8	Depreciation Variance (line 7 - line 6)		2.7	1.1	9.4
	Income Tax Impact				
9	Forecast Capital Cost Allowance Deduction	1	1.9	1.7	1.6
10	Actual Capital Cost Allowance Deduction		12.0	14.6	22.7
11	Actual SR&ED Qualifying Capital Expenditures		4.8	14.7	1.9
12	Difference (line 9 - line 10 - line 11)		(14.9)	(27.5)	(23.1)
13	Net (Decrease) Increase in Regulatory Taxable Income	3	(10.1)	(20.8)	(4.8)
14	Income Tax Rate		25.0%	25.0%	25.0%
15	Income Tax Impact (line 13 x line 14 / (1 - line 14))		(3.4)	(6.9)	(1.6)
16	Less: EB-2020-0290 Eligible Projects Adjustment	4	0.0	0.0	2.8
17	Capital Addition to Variance Account - Non-DRP/Non-PRP (line 5 + line 8 + line 15 - line 16)		2.5	2.7	18.6

For notes see Table 14a

Table 14a
Notes to Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP/Non-PRP (\$M)

Notes:

1	The amounts in line 1 are determined as follows:			
Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for Nuclear Projects - EB-2020-0290 (\$M)				
Line No.		2023	2024	2025
		(a)	(b)	(c)
1a	Forecast Net Plant Rate Base Amount*	14.4	5.6	1.0
2a	Weighted Average Cost of Capital**	5.83%	5.90%	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	0.8	0.3	0.1
4a	ROE Component of Forecast Cost of Capital Amount	0.6	0.2	0.0
5a	Forecast Depreciation^	8.8	8.8	0.2
6a	Forecast Capital Cost Allowance Deduction^	1.9	1.7	1.6
*	Represents the EB-2020-0290 forecast for the Pickering Extended Operations.			
**	Col. (a) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 12: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (b) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 13: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (c) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 14: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).			
^	For lines 5a and 6a, cols. (a) through (c) as shown in EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 3. The sum of the following in cols. (a) through (c) equals \$12.1M, \$11.6M and (\$0.1M) respectively, per EB-2020-0290 Payment Amounts Order, App. E, p. 9: (i) line 3a; (ii) line 5a; and (iii) the result of the following, multiplied by 25% / (1-25%): line 4a plus line 5a minus line 6a.			
2	The amounts in line 2 are determined as follows:			
Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for Nuclear Projects (\$M)				
Line No.		2023	2024	2025
		(a)	(b)	(c)
1b	Gross Plant Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 3b, col. (c))	38.1	121.0	208.9
2b	In-service Addition - Darlington Steam Generator Primary Moisture Separators Replacement ⁺	82.2	87.9	89.4
2bb	In-service Addition - Pickering Extended Operations	0.6	0.0	0.0
3b	Gross Plant Closing Balance (line 1b + line 2b + line 2bb)	121.0	208.9	298.2
4b	Gross Plant Rate Base Amount (line 1b + line 3b)/2 ⁺⁺	93.2	186.9	275.9
5b	Accumulated Depreciation Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 7b, col. (c))	18.9	30.5	40.4
6b	Depreciation - Darlington Steam Generator Primary Moisture Separators Replacement	2.1	5.1	8.2
6bb	Depreciation - Pickering Extended Operations	9.5	4.8	1.4
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b + line 6bb)	30.5	40.4	50.0
8b	Accumulated Depreciation Rate Base Amount (line 5b + line 7b)/2	24.7	35.4	45.2
9b	Net Plant Rate Base Amount (line 4b - line 8b)	68.5	151.5	230.7
+	Col. (a) as shown in Ex. B3-3-1, Table 1a, Note 1 and Ex. D2-1-3, Table 4a, line 13, col. (l). Col. (b) as shown in Ex. B3-3-1 Table 1a, Note 1 and Ex. D2-1-3, Table 4a, line 38, col. (c). Col. (c) as shown in Ex. L-A1-CCC-001, Attachment 1, Table 17, line 38, col. (f).			
++	In-service additions in 2023, 2024, and 2025 for Darlington Steam Generator Primary Moisture Separator exceed \$50M, hence the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.			
3	The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to the difference between (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2023, 2024 and 2025 and (ii) line 4a, for the corresponding year.			
4	Represents a credit adjustment recognized by OPG, in connection with forecasts related to the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project and the Tritium Removal Facility Major Component Replacement Program (included as part of the Nuclear Operations unallocated project portfolio in EB-2020-0290), related to the reference plan amounts against which variances in the non-DRP capital costs are being determined during the period from January 1, 2022 to December 31, 2026 pursuant to the EB-2020-0290 Payment amounts Order. In particular, non-DRP capital reference amounts shown in EB-2020-0290 PAO, App. E, lines 19-20 did not include the forecast revenue requirement impacts for these projects reflected in the approved payment amounts. This adjustment is necessary to accurately match the reference amounts to such forecasts included in the OEB-approved revenue requirements and payment amounts in EB-2020-0290. The adjustment has the effect of lowering amounts that would otherwise be recorded as recoverable from customers in the Capacity Refurbishment Variance Account.			

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 15

Table 15
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - DRP
Summary of Account Transactions 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k)+(l) Total	Budget 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Non-Capital Addition to Variance Account:															
1	Forecast Non-Capital Costs	1	12.4	5.2	24.2	29.4	13.8	3.5	48.4	19.7	24.2	23.6	29.3	25.0		8.4
2	Actual Non-Capital Costs	2	3.1	12.1	24.0	36.1	31.3	1.7	19.0	35.6	22.3	39.0	59.7	10.9		1.8
3	Non-Capital Addition to Variance Account Before Adjustments (line 2 - line 1)		(9.3)	6.9	(0.2)	6.7	17.6	(1.8)	(29.4)	15.8	(1.9)	15.4	30.4	(14.1)		(6.6)
4	Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment - DRP	3	1.1	0.4	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0
5	Less: EB-2016-0152 DRP L&ILW Variable Expenses Adjustment	5	0.0	0.0	2.3	2.3	2.1	3.2	4.6	5.3	0.0	0.0	0.0	0.0		0.0
6	Less: DRP-Related Impact Recorded in Nuclear Liability Deferral Account	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	15.7	15.9	1.9		0.3
7	Non-Capital Addition to Variance Account - DRP (line 3 - line 4 - line 5 - line 6)		(10.4)	6.4	(2.5)	3.9	15.5	(5.0)	(33.9)	10.6	(6.4)	(0.3)	14.5	(16.0)	(27.6)	(6.9)

Notes:
1 The forecast amounts are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Non-Capital Amounts for the Darlington Refurbishment Program (\$M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals col. (c) 2016	col. (d)/12*5 Jan 1 2017 - May 31 2017	col. (g)/12*7 Jun 1 2017 - Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1a	EB-2013-0321 Forecast Costs*	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
2a	EB-2016-0152 Forecast Costs**	6.6	18.2	12.4	12.4	5.2	24.2	41.5	13.8	3.5	48.4	19.7					
3a	EB-2020-0290 Forecasts Costs***												24.2	23.6	29.3	25.0	8.4

* Col. (a) from EB-2013-0321, Ex. F2-7-1, Table 1, line 3, col. (e) less EB-2013-0321, Ex. N2-1-1, p. 8, line 2. Col. (b) from EB-2013-0321, Ex. F2-7-1, line 3, col. (f).

** Cols. (g) to (k) from EB-2016-0152, Ex. F2-1-1, line 5, cols. (e) to (i), as per EB-2016-0152 Payment Amounts Order, App. G, p. 10, Note 12.

*** Cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, p.9.

Col. (a), (d), (e) and (f) from EB-2020-0290, Ex. F2-7-1, Table 1, line 4.

Col. (g) to (k) and col. (n) from Ex. F2-7-1, Table 1, line 4, and col. (l) from Ex. L-A1-CCC-001, Attachment 1, Table 45, line 4, col. (f).

Col. (a) amount is from EB-2016-0152, Ex. H1-1-1, Table 11a, line 9a and col. (b) is calculated as 5/12 of that value.

4 Reflects the impact on the Darlington Refurbishment Program L&ILW variable expenses recorded in the Nuclear Liability Deferral Account as a result of the 2022 ONFA Reference Plan. This adjustment avoids duplication across the Capacity Refurbishment Variance Account and the Nuclear Liability Deferral Account.

5 Represents a credit adjustment recognized by OPG, in connection with low and intermediate level waste (L&ILW) expenses incurred by the DRP, related to the reference plan amounts against which variances in the DRP non-capital costs were being determined during the period from June 1, 2017 to December 31, 2021 pursuant to the EB-2016-0152 Payment Amounts Order. The adjustment was made to correct an error made by OPG in the draft payment amounts order submission in EB-2016-0152, which was subsequently reproduced in the final EB-2016-0152 Payment Amounts Order. In particular, such reference amounts were based on EB-2016-0152, Ex. F2-7-1, line 4, cols. (e) to (i) of OPG's pre-filed evidence and did not reflect the nuclear liability revenue requirement updates approved by the OEB on account of the 2017 ONFA Reference Plan – as summarized in EB-2016-0152, Ex. J21.2 – which included an increase to the forecast DRP L&ILW expenses. The adjustment is necessary to accurately match the reference amounts to such forecasts included in the OEB-approved revenue requirements and payment amounts in EB-2016-0152. The adjustment has the effect of lowering amounts that would otherwise be recorded as recoverable from customers in the Capacity Refurbishment Variance Account.

Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project
Summary of Account Transactions - 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k)+(l) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Capital Addition to Variance Account:														
1	Forecast Cost of Capital Amount	1	10.3	4.3	23.2		38.2	37.1	301.7	330.5	293.2	280.7	419.7	484.9	
2	Actual Net Plant Rate Base Amount	2	340.8	594.6	594.6		693.6	694.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5	8,310.9	
3	Weighted Average Cost of Capital	1	6.85%	6.85%	6.85%		6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	0.1	5.92%	
4	Actual Cost of Capital Amount		23.3	17.0	23.1	40.0	45.1	44.2	218.8	336.8	298.0	343.0	413.8	492.0	
5	Cost of Capital Variance (line 4 - line 1)		13.1	12.6	(0.2)	12.4	6.9	7.1	(82.9)	6.3	4.8	62.2	(5.9)	7.1	
6	Forecast Depreciation	1	4.0	1.7	11.1	12.7	19.2	19.3	148.5	166.9	163.4	163.4	249.8	298.9	
7	Actual Depreciation	2	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8	312.0	
8	Depreciation Variance (line 7 - line 6)		12.2	8.2	6.6	14.8	14.7	15.1	(25.3)	17.7	21.3	62.7	22.0	13.0	
	Income Tax Impact:														
9	Forecast Capital Cost Allowance Deduction	1	66.8	27.8	106.8	134.6	283.7	354.4	380.8	383.2	523.6	550.7	540.3	538.9	
10	Actual Capital Cost Allowance Deduction	6	118.7	78.8	104.3	183.1	243.6	412.4	431.6	454.0	489.5	527.3	525.5	529.5	
11	SR&ED Qualifying Capital Expenditures		62.4	0.0	20.7	20.7	18.8	0.0	0.0	0.0	0.0	0.0	-	0.0	
12	Difference (line 9 - line 10 - line 11)		(114.3)	(51.0)	(18.2)	(69.1)	21.3	(58.0)	(50.8)	(70.8)	34.0	23.4	14.8	9.4	
13	Net (Decrease) Increase in Regulatory Taxable Income	3	(94.2)	(35.0)	(11.7)	(46.7)	40.2	(38.5)	(127.0)	(49.3)	58.6	127.7	32.9	27.1	
14	Income Tax Rate		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	
15	Income Tax Impact (line 13 x line 14 / (1 - line 14))		(31.4)	(11.7)	(3.9)	(15.6)	13.4	(12.8)	(42.3)	(16.4)	19.5	42.6	11.0	9.0	
16	Capital Addition to Variance Account (line 5 + line 8 + line 15)		(6.2)	9.2	2.5	11.6	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0	29.1	
17	Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment	5	5.1	2.1	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
18	Addition to Variance Account-Capital Portion DRP (line 16 - line 17)		(11.2)	7.1	2.5	9.5	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0	29.1	
19	Less: Accelerated Investment Incentive CCA - DRP	4	0.0	0.0	0.0	0.0	0.0	(18.9)	(19.9)	3.1	0.0	0.0	0.0	0.0	
20	Total Capital Additon to Variance Account - Capital Portion DRP (line 18 - line 19)		(11.2)	7.1	2.5	9.5	35.0	28.3	(130.6)	4.4	45.638	167.552	27.0	29.1	204.7

For notes see Table 16a

Numbers may not add due to rounding.

Table 16a
Notes to Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project

Notes:

1 The amounts in line 1 are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for the Darlington Refurbishment Program (\$M)																
Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals to col. (c) 2016	col. (d) / 12*5 Jan 1 2017- May 31 2017	col. (g) / 12*7 June 1 2017- Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1a	Forecast Net Plant Rate Base Amount*	116.0	184.3					598.1	587.7	572.9	4,685.3	5,140.7	4,978.0	4,815.3	7,114.2	8,191.6
2a	Weighted Average Cost of Capital**	6.86%	6.85%					6.65%	6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	5.90%	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	8.0	12.6	10.3	10.3	4.3	23.2	39.8	38.2	37.1	301.7	330.5	293.2	280.7	419.7	484.9
4a	ROE Component of Forecast Cost of Capital Amount***	4.9	7.7	6.3	6.3	2.6	13.8	23.6	23.2	22.6	185.1	203.1	194.0	187.7	277.2	319.2
5a	Forecast Depreciation*	3.0	5.0	4.0	4.0	1.7	11.1	19.0	19.2	19.3	148.5	166.9	163.4	163.4	249.8	298.9
6a	Forecast Capital Cost Allowance Deduction****	39.3	94.3	66.8	66.8	27.8	106.8	183.1	283.7	354.4	380.8	383.2	523.6	550.7	540.3	538.9

- * Cols. (a) and (b) from EB-2013-0321, Ex. L-4.9-1-Staff-048, Chart 1, "Total" line less "Heavy Water & Drum Handling Facility" line.
Cols. (g) to (k) from EB-2016-0152, Ex. L-2.2-1-Staff-009, Attachment 1, "Total" line less "Heavy Water Storage & Drum Handling Facility" line.
Line 1a cols. (l) to (o) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 1, cols. (a) to (d). Line 5a cols. (l) to (o) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 6, cols. (a) to (d).
- ** Cols. (a) and (b) from EB-2013-0321 Payment Amounts Order, App. A, Tables 5b and 6b: line 6, col. (c).
Cols. (g) to (k) from EB-2016-0152 Payment Amounts Order, App. A, Tables 11 to 15: line 6, col. (c).
Cols. (l) to (o) from EB-2020-0290 Payment Amounts Order, App. A, Tables 11 to 14: line 4, col. (b) x col. (c), plus line 5a, col. (c) x line 5b, col. (b).
- *** The ROE component of the cost of capital forecast is equal to line 1a multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rates as follows: 2016 and Jan 1, 2017 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2025 - 8.66%.
- **** Cols. (a) and (b) from EB-2013-0321, Ex. D2-2-1, p. 29, Note 2.
Cols. (g) to (k) from EB-2016-0152, Ex. F4-2-1, Table 3b, Note 3.
Cols. (l) to (o) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 11, cols. (a) to (d).

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for the Darlington Refurbishment Program (\$M)													
Line No.		2016	Jan 1 2017- May 31 2017	June 1 2017- Dec 31 2017	(b) + (c) Total 2017	2018	2019	2020	2021	2022	2023	2024	2025
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1b	Gross Plant Opening Balance (col. (a) from EB-2020-0290, Ex. B3-3-1, Table 1, line 2, col. (a))	280.1			444.5	750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5
2b	In-service Addition - Darlington Refurbishment - Unit Refurbishments	0.0			0.0	0.0	0.0	4,765.0	6.2	(2.5)	2,240.1	1,739.6	28.5
3b	In-service Addition - Darlington Refurbishment - Early In-Service	103.4			44.9	22.5	7.6	2.2	1.5	2.9	0.0	0.0	0.0
4b	In-service Addition - Darlington Refurbishment - Facilities & Infrastructure Projects	43.0			16.9	0.9	0.1	10.0	(1.4)	(0.9)	0.0	0.0	0.0
5b	In-service Addition - Darlington Refurbishment - Safety Improvement Opportunities	17.9			244.1	11.1	8.2	(3.0)	1.5	4.2	0.0	2.3	0.0
6b	Total In-Service Additions (line 2b + line 3b + line 4b + line 5b)*	164.4	241.0	64.9	305.9	34.5	16.0	4,774.1	7.8	3.7	2,240.1	1,741.9	28.5
7b	Gross Plant Closing Balance (line 1b + line 6b)	444.5			750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5	9,597.0
8b	Gross Plant Rate Base Amount (line 1b + line 7b)/2**	362.3			638.0	767.7	792.9	3,585.1	5,579.0	5,584.7	6,614.0	7,993.4	9,582.7
9b	Accumulated Depreciation Opening Balance (col. (a) from EB-2020-0290, Ex. B3-4-1, Table 1, line 2, col. (a))	13.5			29.6	57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9
10b	Depreciation†	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8	312.0
11b	Accumulated Depreciation Closing Balance (line 9b + line 10b)	29.6			57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9	1,427.9
12b	Accumulated Depreciation Rate Base Amount (line 9b + line 11b)/2***	21.5			43.4	74.1	108.2	187.0	341.0	525.6	731.0	980.0	1,271.9
13b	Net Plant Rate Base Amount (line 8b - line 12b)	340.8			594.6	693.6	684.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5	8,310.9

- + In-service additions - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. D2-2-9, Table 5a, excluding the D2O Storage Project. Cols. (g) to (k) from Ex. D2-2-3, Table 5a, excluding the D2O Storage Project. Col. (l) from Ex. L-A1-CCC-001, Attachment 1, Table 20, excluding the D2O Storage Project.
Depreciation - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. F4-1-1, Table 2, line 2, cols. (a) to (d). Cols. (g) to (k) from Ex. F4-1-1, Table 2, line 2, cols. (a) to (e). Col. (l) from Ex. L-A1-CCC-001, Attachment 1, Table 55, line 2, col. (f).
- ++ Total in-service additions include the following amounts over \$50M: 2016 - \$88.1M for R&FR - Tooling, 2017 - \$191.2 for Safety Improvement Opportunities, 2020 - \$4,765.0M for Unit 2, 2023 - \$2,221.8M for Unit 3, and 2024 - \$1,689.9M for Unit 1. For these in-service additions, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average. Amounts at line 8b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-3-1, Table 1, col. (f), lines 2, 10, 18 and 26. Cols. (g) to (k) from Ex. B3-3-1, Table 1, col. (f), lines 2, 11, 20, 29 and 38. Col. (l) from Ex. L-A1-CCC-001, Attachment 1, Table 6, col. (f), line 2.
- +++ Amounts at line 12b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-4-1, Table 1, col. (e), lines 2, 10, 18 and 26. Cols. (g) to (k) from Ex. B3-4-1, Table 1, col. (e), lines 2, 11, 20, 29 and 38. Col. (l) from Ex. L-A1-CCC-001, Attachment 1, Table 7, col. (e), line 2.
- 3 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to the difference between: (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the following OEB-approved ROE rates: 2016 and Jan 1 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2025 - 8.66%; and (ii) line 4a, cols. (d) to (f), (h) to (o).
- 4 Accelerated Investment Incentive CCA is included within the total CCA at line 10, and such amounts for Darlington Refurbishment Program recorded in the Capacity Refurbishment Variance Account have been separately approved for disposition in EB-2020-0290 Payment Amounts Order, Appendix D, Table 1, line 7, col. (f) and EB-2023-0336 Decision and Order, Attachment A, Table 2, line 6, col. (e).
- 5 Col. (a) amount is from EB-2016-0152 Ex. H1-1-1, Table 11, line 33 and col. (b) is calculated as 5/12 of that value.
- 6 Amounts are net of impacts to capital cost allowance from the permanent rate base disallowance applied to the D2O Storage Project by the OEB in the EB-2020-0290 Decision and Order.

Numbers may not add due to rounding.

Table 17
Nuclear Liability Deferral Account
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2022:					
1	Depreciation Expense	1	80.5	80.5	1.1	1.1
	Return on Rate Base					
2	Average Asset Retirement Costs	2	151.8	71.2	30.4	29.3
3	Weighted Average Cost of Capital	3	5.83%	5.90%	5.92%	5.92%
4	Return on Rate Base (line 2 x line 3)		8.8	4.2	1.8	1.7
	Variable Expenses					
5	Used Fuel Storage and Disposal Variable Expenses	5	0.3	0.7	1.0	1.5
6	Low & Intermediate Level Waste Management Variable Expenses	5	28.8	29.4	12.3	7.9
7	Total Variable Expenses (line 5 + line 6)		29.1	30.1	13.3	9.4
	Income Tax Impact					
8	Forecast Contributions to Segregated Funds	6	100.6	100.6	0.0	0.0
9	Contributions to Segregated Funds based on Current Approved ONFA Reference Plan	7	200.1	200.1	116.4	39.2
10	Increase in Contributions to Segregated Funds (line 8 - line 9)		(99.5)	(99.5)	(116.4)	(39.2)
11	Return on Rate Base - ROE Component (line 2 x 45% x 8.66%)		5.9	2.8	1.2	1.1
12	Net Increase in Regulatory Taxable Income (line 1 + line 7 + line 10 + line 11)		16.1	14.0	(100.8)	(27.6)
13	Income Tax Rate		25.0%	25.0%	25.0%	25.0%
14	Income Tax Impact (line 12 x line 13 / (1 - line 13))		5.4	4.7	(33.6)	(9.2)
15	Addition to Deferral Account - Year-End 2021 ARO / ARC Adjustment (lines 1 + 4 + 7 + 14)		123.9	119.5	(17.4)	3.0
16	Addition to Deferral Account - Change in Pickering Station End-of-Life Dates (December 31, 2020 End-of-Life Extension)	4	69.4	67.9	19.6	19.6
17	Total Addition to Deferral Account (line 15 + line 16)		193.3	187.5	2.2	22.6

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

Table to Note 1 - Change in Depreciation Expense (\$M)					
Line No.		Pickering Units 1 & 4	Pickering Units 5 - 8	Darlington	(a) + (b) + (c) Total
		(a)	(b)	(c)	(d)
	Incremental Asset Retirement Cost ("ARC") Continuity:				
1a	ARC Adjustment at December 31, 2021 (EB-2023-0336, Ex. H1-1-1, Table 18a, line 7b, cols. (a) to (d))**	254.8	(16.5)	34.2	272.6
2a	Remaining Useful Life as at December 31, 2021 (years)*	3.0	3.0	31.0	
3a	2022 Annual Incremental Depreciation (line 1a / line 2a)	84.9	(5.5)	1.1	80.5
4a	Incremental ARC at December 31, 2022 (EB-2023-0336, Ex. H1-1-1, Table 18, Note 1, line 4a)	169.9	(11.0)	33.1	192.0
5a	Remaining Useful Life as at December 31, 2022 (years)*	2.0	2.0	30.0	
6a	2023 Annual Incremental Depreciation (line 4a / line 5a)	84.9	(5.5)	1.1	80.5
7a	Incremental ARC at December 31, 2023 (line 4a - line 6a)	84.9	(5.5)	32.0	111.5
8a	Remaining Useful Life as at December 31, 2023 (years)*	1.0	1.0	29.0	
9a	2024 Annual Incremental Depreciation (line 7a / line 8a)	84.9	(5.5)	1.1	80.5
10a	Incremental ARC at December 31, 2024 (line 7a - line 9a)	0.0	0.0	30.9	30.9
11a	Remaining Useful Life as at December 31, 2024 (years)*	0.0	0.0	28.0	
12a	2025 Annual Incremental Depreciation (line 10a / line 11a)	0.0	0.0	1.1	1.1
13a	Incremental ARC at December 31, 2025 (line 10a - line 12a)	0.0	0.0	29.8	29.8
14a	Remaining Useful Life as at December 31, 2025 (years)*	0.0	0.0	27.0	
15a	2026 Annual Incremental Depreciation (line 13a / line 14a)	0.0	0.0	1.1	1.1
16a	Incremental ARC at December 31, 2026 (line 13a - line 15a)	0.0	0.0	28.7	28.7
*	A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.				
**	Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 14, cols. (a) through (d), respectively.				
2	Col. (a) calculated as (line 4a, col. (d) + line 7a, col. (d)) / 2. Col. (b) calculated as (line 7a, col.(d) + line 10a, col. (d)) / 2. Col. (c) calculated as (line 10a, col.(d) + line 13a, col. (d)) / 2. Col. (d) calculated as (line 13a, col.(d) + line 16a, col. (d)) / 2.				
3	Col. (a) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (b) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (c) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (d) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).				
4	Cols. (a), (b) and (d) from Ex. H1-1-1, Table 18, line 22, cols. (a), (b) and (d). Col. (c) from Ex. L-H1-Staff-260, Attachment 1, Table 18, line 22, col. (c). Represents the nuclear liabilities component of the revenue requirement impacts arising from the extension of station end-of-life dates for Pickering Units 1 and 4 to December 31, 2024, effective December 31, 2020. As the current approved ONFA Reference Plan reflects this change effective January 1, 2022, this impact is recorded in the Nuclear Liability Deferral Account beginning in 2022. Prior to 2022, the impact was recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account as this change in end-of-life dates was not yet reflected in the current approved ONFA Reference Plan.				
5	Values are calculated as the difference between: (A) the product of (i) corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding year in the EB-2020-0290 nuclear revenue requirements, and (B) the product of (i) the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs applicable following the changes in nuclear liabilities as a result of the extension of station end-of-life dates for Pickering Units 1 and 4 effective December 31, 2020, and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding years in the EB-2020-0290 nuclear revenue requirements.				
6	Per EB-2020-0290, Ex. C2-1-1, Table 2, line 15, cols. (h) through (k).				
7	Cols (a), (b) and (d) from Ex. C2-1-1, Table 2, line 14, cols. (d), (e) and (g), respectively. Col. (c) from Ex. L-A1-CCC-001, Attachment 1, Table 12, line 14, col. (a).				

Numbers may not add due to rounding.

Table 18
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension¹
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Description	Note	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Cost of Capital					
1	Asset Retirement Cost ("ARC") Rate Base (Note 4, line 4h)		2.3	0.6	(0.3)	(0.2)
2	Non-ARC Rate Base (Note 5, line 5f)		3.1	1.0	0.0	0.0
3	Total Return on Rate Base Impact (line 1 + line 2)		5.5	1.6	(0.3)	(0.2)
	Depreciation Expense:					
4	Asset Retirement Costs (Note 2, col. (f))		29.7	29.7	(0.2)	(0.2)
5	Non-Asset Retirement Costs (Note 3, line 3c)		38.1	34.6	0.0	0.0
6	Total Depreciation Expense Impact (line 4 + line 5)		67.8	64.3	(0.2)	(0.2)
	Other Expenses:					
7	Used Fuel Storage and Disposal Variable Expenses	6	19.4	19.9	14.5	14.6
8	Low & Intermediate Level Waste Management Variable Expenses	6, 7	0.8	0.8	0.6	0.4
9	Total Variable Expenses Impact (line 7 + line 8)		20.2	20.7	15.1	15.1
	Income Taxes:					
10	Return on Rate Base - Non-ARC Impact - ROE Component (Note 5, line 5g x (25%/75%))		0.7	0.2	0.0	0.0
11	Depreciation Expense on Non-Asset Retirement Costs (line 5 x (25%/75%))		12.7	11.5	0.0	0.0
12	Total Non-ARC Income Tax Impact (line 10 + line 11)		13.4	11.8	0.0	0.0
13	Return on Rate Base - ARC Impact (Note 4, line 4k x (25%/75%))		0.5	0.1	(0.1)	(0.1)
14	Depreciation Expense on Asset Retirement Costs (line 4 x (25%/75%))		9.9	9.9	(0.1)	(0.1)
15	Used Fuel Storage and Disposal Variable Expenses (line 7 x (25%/75%))		6.5	6.6	4.8	4.9
16	Low & Intermediate Level Waste Management Variable Expenses (line 8 x (25%/75%))		0.3	0.3	0.2	0.1
17	Total Nuclear Liabilities Income Tax Impact (line 13 + line 14 + line 15 + line 16)		17.2	16.9	4.9	4.9
18	Total Income Tax Impact (line 12 + line 17)		30.5	28.7	4.9	4.9
19	Revenue Requirement Impact - Nuclear Liabilities (line 1 + line 4 + line 9 + line 17)		69.4	67.9	19.6	19.6
20	Revenue Requirement Impact - Non-ARC (line 2 + line 5 + line 12)		54.6	47.4	0.0	0.0
21	Total Revenue Requirement Impact (line 19 + line 20)		124.0	115.4	19.6	19.6
22	Less: Revenue Requirement Impact Recorded in Nuclear Liability Deferral Account Beginning Jan. 1, 2022 (line 19)	8	69.4	67.9	19.6	19.6
23	Total Addition to Deferral Account (line 21 - line 22)		54.6	47.4	0.0	0.0

For notes see Tables 18a and 18b.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 18a

Table 18a
Notes to Table 18

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension (\$M)

- 1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p.1. Amounts are as set out in EB-2020-0290 Ex. L-F-01-Staff-271, Att. 1, Table 2, other than those that reflect changes between the EB-2020-0290 proposed and OEB approved revenue requirement for the corresponding year, subject to rounding differences.
- 2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense (\$M)					(a)+(b)+(c)	ARC Depreciation per EB-2020-0290***	(d) - (e)
Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	Total		Impact of Year-End 2020 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)
2a	Asset Retirement Cost as at December 31, 2020 Before Pickering Units 1 & 4 End-of-Life Adjustment*	63.3	187.8	113.9	365.2		
2b	Asset Retirement Cost Adjustment as at December 31, 2020 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 7, cols. (a) through (d).)	50.4	5.6	(4.8)	51.1		
2c	Unamortized Asset Retirement Cost as at December 31, 2020 (line 2a + line 2b)	113.6	193.4	109.1	416.2		
2d	Remaining Useful Life as at December 31, 2020 (years)**	4.0	4.0	32.0			
2e	Annual Depreciation (line 2c / line 2d)	28.4	48.3	3.4	80.2	82.2	(2.0)
2f	Unamortized Asset Retirement Cost as at December 31, 2021 (line 2c - line 2e)	85.2	145.0	105.7	336.0		
2g	Remaining Useful Life as at December 31, 2021 (years)**	3.0	3.0	31.0			
2h	2022 Annual Depreciation (line 2f / line 2g)	28.4	48.3	3.4	80.2	82.2	(2.0)
2i	Unamortized Asset Retirement Cost as at December 31, 2022* (line 2f - line 2h)	56.8	96.7	102.3	255.8		
2j	Remaining Useful Life as at December 31, 2022 (years)**	2.0	2.0	30.0			
2k	2023 Annual Depreciation (line 2i / line 2j)	28.4	48.3	3.4	80.2	50.5	29.7
2l	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2i - line 2k)	28.4	48.3	98.9	175.7		
2m	Remaining Useful Life as at December 31, 2023 (years)**	1.0	1.0	29.0			
2n	2024 Annual Depreciation (line 2l / line 2m)	28.4	48.3	3.4	80.2	50.5	29.7
2o	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2l - line 2n)	0.0	0.0	95.5	95.5		
2p	Remaining Useful Life as at December 31, 2024 (years)**	0.0	0.0	28.0			
2q	2025 Annual Depreciation (line 2o / line 2p)	0.0	0.0	3.4	3.4	3.6	(0.2)
2r	Unamortized Asset Retirement Cost as at December 31, 2025 (line 2o - line 2q)	0.0	0.0	92.1	92.1		
2s	Remaining Useful Life as at December 31, 2025 (years)**	0.0	0.0	27.0			
2t	2026 Annual Depreciation (line 2r / line 2s)	0.0	0.0	3.4	3.4	3.6	(0.2)
2u	Unamortized Asset Retirement Cost as at December 31, 2026 (line 2r - line 2t)	0.0	0.0	88.7	88.7		

* From EB-2023-0336, Ex. H1-1-1, Table 19a, line 2a, cols. (a) to (d) (differences due to rounding).

** A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.

*** Per EB-2018-0002 OEB Staff Interrogatory #1, Schedule 1-Staff-1, Att. 1, Table 1a, line 1n, col. (d) for 2021 and EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 8, 17, 26, 35 and 44 for 2022 to 2026, respectively.

- 3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense (\$M)					Budget 2026
Line No.		Actual 2023	Actual 2024	Actual 2025	(d)
		(a)	(b)	(c)	
3a	Unadjusted Non-ARC Depreciation and Amortization Expense - December 31, 2022 Pickering Units 1 & 4 End-of-Life*	421.0	528.2	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 1 & 4 End-of-Life#	459.1	562.9	0.4	0.0
3c	Impact of Pickering Units 1 & 4 End-of-Life Extension (line 3b less line 3a)	38.1	34.6	0.0	0.0

+ Cols. (a) and (b) from EB-2020-0290 Ex. B3-4-1, Table 2, cols. (b) to (d), lines 30 and 38, respectively. Cols. (c) and (d) from EB-2020-0290 Ex. B3-4-1, Table 3, cols. (b) to (d), lines 4 and 12, respectively.

Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2023 to 2025) and holding all other variables constant, effective January 1, 2022 onwards.

- 4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base (\$M)					Budget 2026
Line No.		Actual 2023	Actual 2024	Actual 2025	(d)
		(a)	(b)	(c)	
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	215.7	135.6	93.8	90.4
4b	Average UNL****	(107.0)	(290.8)	(452.1)	(547.2)
4c	Weighted Average Accretion Rate*	4.86%	4.86%	4.86%	4.86%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)**	0.0	0.0	0.0	0.0
4e	Return on Rate Base at Weighted Average Cost of Capital (line 4a x WACC, as line 4b < 0)***	12.6	8.0	5.6	5.4
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate^	0.0	0.0	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital^^	10.2	7.4	5.8	5.6
4h	Impact of Pickering Units 1 & 4 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g))	2.3	0.6	(0.3)	(0.2)
4i	ROE Component of Line 4e Cost of Capital ((line 4a x 45% x 8.66%), as line 4b < 0)	8.4	5.3	3.7	3.5
4j	ROE Component of Line 4g Cost of Capital^^^	6.8	4.9	3.8	3.7
4k	Impact of Pickering Units 1 & 4 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4i - line 4j))	1.6	0.4	(0.2)	(0.2)

+ From EB-2020-0290, Ex. L-A1-2-Staff-002, Att. 1, Table 5, line 7, col. (c).

++ When UNL is a negative value, no return on rate base at weighted average accretion is recorded and the return at rate base is limited to average ARC at line 4a multiplied by the OEB-approved weighted average cost of capital (WACC), as shown in line 4e.

+++ Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (d) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

++++ From EB-2020-0290, Ex. L-F-01-Staff-271, Att. 1, Table 2b, line 4b, cols. (b)-(e) for the corresponding years.

^ EB-2020-0290 Payment Amounts Order, App. A: Table 12, line 7, col. (d) for 2023, Table 13, line 7, col. (d) for 2024, Table 14, line 7, col. (d) for 2025, Table 15, line 7, col. (d) for 2026.

^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) multiplied by WACC (see note +++).
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) multiplied by WACC (see note +++).
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) multiplied by WACC (see note +++).
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) multiplied by WACC (see note +++).

^^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 18b

Table 18b
Notes to Table 18 - Continued
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension (\$M)

5 Cost of Capital for Non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base (\$M)					
Line No.		Actual 2023	Actual 2024	Actual 2025	Budget 2026
		(a)	(b)	(c)	(d)
5a	Opening Non-ARC Net Plant Balance Impact ^{##}	72.7	34.6	0.0	0.0
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	(38.1)	(34.6)	0.0	0.0
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	34.6	0.0	0.0	0.0
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	53.7	17.3	0.0	0.0
5e	Weighted Average Cost of Capital ^{###}	5.83%	5.90%	5.92%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	3.1	1.0	0.0	0.0
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	2.1	0.7	0.0	0.0

- ^{##} Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 19b, line 5c., col. (b).
- ^{###} See Ex. H1-1-1, Table 18a, Note +++.
- 6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirements for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 2.01% discount rate used to determine the year-end 2020 ARO adjustment reflecting the Pickering Units 1 and 4 end-of-life extension, and (ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses included in the EB-2020-0290 nuclear revenue requirements.
- 7 Actual 2023, 2024 and 2025 amounts exclude \$1.3M, \$1.1M and \$0.4M respectively, of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2026 amount of \$0.1M is excluded for the same reason.
- 8 Cols. (a), (b) and (d), refer to Ex. H1-1-1, Table 17, Note 4. Col. (c) refer to Ex. L-H1-Staff-260, Attachment 1, Table 17, Note 4.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 19

Table 19
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension¹
Summary of Account Transactions - 2024 and 2025 (\$M)

Line No.	Description	Note	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)
	Cost of Capital:				
1	Asset Retirement Cost ("ARC") Rate Base (Note 4, line 4j)		18.5	17.4	17.1
2	Non-ARC Rate Base (Note 5, line 5f)		1.9	3.6	3.1
3	Total Return on Rate Base Impact (line 1 + line 2)		20.5	21.0	20.2
	Depreciation Expense:				
4	Asset Retirement Costs (Note 2, col. (h))		78.1	6.8	6.8
5	Non-Asset Retirement Costs (Note 3, line 3c)		(65.5)	8.9	8.7
6	Total Depreciation Expense Impact (line 4 + line 5)		12.6	15.7	15.6
	Other Expenses:				
7	Used Fuel Storage and Disposal Variable Expenses	6	(29.9)	(21.9)	(21.8)
8	Low & Intermediate Level Waste Management Variable Expenses	6,7	(5.8)	(4.4)	(3.1)
9	Total Variable Expenses Impact (line 7 + line 8)		(35.7)	(26.2)	(24.9)
	Income Taxes:				
10	Return on Rate Base - Non-ARC Impact - ROE Component (Note 5, line 5g x (25%/75%))		0.4	0.8	0.7
11	Depreciation Expense on Non-Asset Retirement Costs (line 5 x (25%/75%))		(21.8)	3.0	2.9
12	Total Non-ARC Income Tax Impact (line 10 + line 11)		(21.4)	3.7	3.6
13	Return on Rate Base - ARC Impact (Note 4, line 4o x (25%/75%))		7.6	6.6	6.5
14	Depreciation Expense on Asset Retirement Costs (line 4 x (25%/75%))		26.0	2.3	2.3
15	Used Fuel Storage and Disposal Variable Expenses (line 7 x (25%/75%))		(10.0)	(7.3)	(7.3)
16	Low & Intermediate Level Waste Management Variable Expenses (line 8 x (25%/75%))		(1.9)	(1.5)	(1.0)
17	Total Nuclear Liabilities Income Tax Impact (line 13 + line 14 + line 15 + line 16)		21.7	0.2	0.5
18	Total Income Tax Impact (line 12 + line 17)		0.3	3.9	4.1
19	Revenue Requirement Impact - Nuclear Liabilities (line 1 + line 4 + line 9 + line 17)		82.6	(1.9)	(0.4)
20	Revenue Requirement Impact - Non-ARC (line 2 + line 5 + line 12)		(84.9)	16.2	15.4
21	Total Addition to Deferral Account (line 19 + line 20)		(2.3)	14.4	15.0

For notes see Tables 19a and 19b.

Table 19a
Notes to Table 19
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension (\$M)

- 1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p. 1.
2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense (\$M)									
Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	(a)+(b)+(c) Total	ARC Depreciation per EB-2020-0290 *	Impact of Year-End 2020 Adjustment **	Impact of 2022 ONFA Reference Plan (Year-End 2021) Adjustment ***	(d) - (e) - (f) - (g) Impact of Year-End 2023 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2a	Asset Retirement Cost as at December 31, 2023 Before Pickering Units 5-8 End-of-Life Adjustment (Col. (d) from Ex. C2-1-1, Table 2, line 23, col. (d).)	113.1	42.7	130.9	286.7				
2b	Asset Retirement Cost Adjustment as at December 31, 2023 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 22, cols. (a) through (d).)	114.3	490.7	(130.9)	474.1				
2c	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2a + line 2b)	227.4	533.4	0.0	760.8				
2d	Remaining Useful Life as at December 31, 2023 (years) #	1.0	47.0	29.0					
2e	2024 Annual Depreciation (line 2c / line 2d) (Col. (d) from Ex. C2-1-1, Table 2, line 22, col. (e) and from Ex. F4-1-1, Table 2, line 9, col. (e).)	227.4	11.3	0.0	238.8	50.5	29.7	80.5	78.1
2f	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2c - line 2e)	0.0	522.0	0.0	522.0				
2g	Remaining Useful Life as at December 31, 2024 (years) #	0.0	46.0	28.0					
2h	2025 Annual Depreciation (line 2f / line 2g)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2i	Unamortized 2025 Asset Retirement Cost as at December 31, 2025 (line 2f - line 2h)	0.0	510.7	0.0	510.7				
2j	Remaining Useful Life as at December 31, 2025 (years) #	0.0	45.0	27.0					
2k	2026 Annual Depreciation (line 2i / line 2j)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2l	Unamortized 2026 Asset Retirement Cost as at December 31, 2026 (line 2i - line 2k)	0.0	499.3	0.0	499.3				

* Per EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 26, 35 and 44 for 2024 to 2026, respectively.
** From Ex. H1-1-1, Table 18, line 4, cols. (b) and (d) for 2024 and 2026, respectively.
From Ex. L-H1-Staff-260, Attachment 1, Table 18, line 4, col. (c) for 2025.
*** Ex. H1-1-1, Table 17, line 1, cols. (b) and (d) for 2024 and 2026, respectively.
From Ex. L-H1-Staff-260, Attachment 1, Table 17, line 1, col. (c) for 2025.
A common end of life date of December 31, 2024 is used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations. An end of life date of December 31, 2070 is used to depreciate ARC for Pickering Units 5-8.

- 3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense (\$M)				
Line No.		Actual 2024	Actual 2025	Budget 2026
		(a)	(b)	(c)
3a	Unadjusted non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 5-8 End of Life*	562.9	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2070 Pickering Units 5-8 End-of Life**	497.4	9.2	8.7
3c	Impact of Pickering End-of-Life Extension (line 3b less line 3a)	(65.5)	8.9	8.7

* Col. (a) from Ex. H1-1-1, Table 18a, line 3b, col. (b).
Col. (b) from Ex. L-H1-Staff-260, Attachment 1, Table 18a, line 3b, col. (c).
Col. (c) from Ex. H1-1-1, Table 18a, line 3b, col. (d).
** Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2024-2026) and holding all other variables constant, effective January 1, 2022.

Numbers may not add due to rounding.

Table 19b
Notes to Table 19 - Continued
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account (December 31, 2023 End-of-Life Extension) (\$M)

4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base (\$M)			
Line No.		Actual 2024	Actual 2025
		(a)	(b)
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	641.4	516.4
4b	Average UNL	774.0	640.3
4c	Weighted Average Accretion Rate (Ex. C1-1-1, Table 9, line 7, col. (c))	4.79%	4.79%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)	30.7	24.7
4e	Return on Rate Base at Weighted Average Cost of Capital ((line 4a - line 4b) x WACC), if line 4a > line 4b) [#]	0.0	0.0
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate (from L-H1-Staff-260, Attachment 1, Table 18a, line 4f)	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital (from L-H1-Staff-260, Attachment 1, Table 18a, line 4g)	7.4	5.8
4h	Impact of Year-End 2020 ARO Adjustment (from Ex. L-H1-Staff-260, Attachment 1, Table 18a, line 4h, cols. (b) to (d))	0.6	(0.3)
4i	Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment (from L-H1-Staff-260, Attachment 1, Table 17, line 4, cols. (b) to (d))	4.2	1.8
4j	Impact of Pickering Units 5-8 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g) - (line 4h + line 4i))	18.5	17.4
4k	ROE Component of Line 4e Cost of Capital (((line 4a-4b) x 45% x 8.66%), if line 4a > line 4b)	0.0	0.0
4l	ROE Component of Line 4g Cost of Capital (from L-H1-Staff-260, Attachment 1, Table 18a, line 4j, cols. (b) to (d))	4.9	3.8
4m	ROE Component of Impact of Year-End 2020 ARO Adjustment (from Ex. L-H1-Staff-260, Attachment 1, Table 18a, line 4k, cols. (b) to (d))	0.4	(0.2)
4n	ROE Component of Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment [^]	2.8	1.2
4o	Impact of Pickering Units 5-8 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4k - line 4l) - line 4m - line 4n)	22.7	19.9

[#] Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

[^] Col. (a) Ex. H1-1-1, Table 17, line 2, col. (b) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (b) Ex. L- H1-Staff-260, Att.1, Table 17, line 2, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (c) Ex. H1-1-1, Table 17, line 2, col. (d) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.

5 Cost of Capital for non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base (\$M)			
Line No.		Actual 2024	Actual 2025
		(a)	(b)
5a	Opening Non-ARC Net Plant Balance Impact	0.0	65.5
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	65.5	(8.9)
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	65.5	56.6
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	32.7	61.0
5e	Weighted Average Cost of Capital ⁺	5.90%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	1.9	3.6
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	1.3	2.4

⁺ For calculation of WACC, see note [#]

- 6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirement for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 3.93% discount rate used to determine the year-end 2023 ARO adjustment reflecting the Pickering Units 5-8 end-of-life extension, and (ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses reflecting the 2.45% discount rate used to record variable expenses during 2022 and 2023, following the year-end 2021 ARO adjustment reflecting the impact of the 2022 ONFA Reference Plan.
- 7 Actual 2024 and 2025 amounts exclude \$7.5M and \$1.7M of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2026 amount of \$0.2M is excluded for the same reason.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 20

Table 20
Nuclear Development Variance Account - Darlington New Nuclear Program
Summary of Account Transactions - 2023, 2024 and 2025 (\$M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)
	<u>Capital Addition to Variance Account:</u>				
	<u>Income Tax Impact:</u>				
1	Forecast Capital Cost Allowance Deduction		0.0	0.0	0.0
2	Actual Capital Cost Allowance Deduction	3	0.0	23.9	(3.4)
3	Actual SR&ED Qualifying Expenditures		21.1	56.0	44.5
4	Recapture on Transfer of Assets to DNNP LP	4	0.0	0.0	(20.5)
5	Transfer of Cumulative SR&ED Qualifying Expenditures to DNNP LP	5	0.0	0.0	(121.6)
6	Difference (line 1 - line 2 - line 3 - line 4 - line 5)		(21.1)	(79.9)	101.0
7	Net Increase (Decrease) Increase in Regulatory Taxable Income (line 6)		(21.1)	(79.9)	101.0
8	Income Tax Rate		25%	25%	25%
9	Income Tax Impact (line 7 x line 8/ (1 - line 8))		(7.0)	(26.6)	33.7
10	Capital Addition to Variance Account (line 9)		(7.0)	(26.6)	33.7
	<u>Non-Capital Addition to Variance Account:</u>				
11	Forecast Costs	1	2.2	2.3	2.3
12	Actual Costs	2	1.1	2.3	13.4
13	Difference (line 12 - line 11)		(1.1)	0.1	11.1
14	Non-Capital Addition to Variance Account (line 13)		(1.1)	0.1	11.1
15	Total Addition to Variance Account (line 10 + line 14)		(8.1)	(26.5)	44.8

Notes:

- 1 From EB-2020-0290 Payment Amounts Order, App. E, p.16.
- 2 Cols. (a) and (b) from Ex. F2-1-1, Table 1a, line 8, cols. (d) and (e). Col. (c) from Ex. L-A1-CCC-001, Attachment 1, Table 38, line 8, col. (f).
- 3 Col. (c) represents the adjustment to 2024 CCA - previously recorded based on the year's tax provision - to reflect the 2024 income tax return completed in June 2025.
- 4 As noted in Ex. L-A1-CCC-001, Attachment 1, Table 61, Note 5, the transfer of assets related to the DNNP facilities from OPG to DNNP LP resulted in income to OPG in the form of recapture of \$20.5M for CCA claimed previously (and credited in the Nuclear Development Variance Account; refer to line 2) for the DNNP facilities. As a result, the overall impact to the account from these deductions during 2023-2025 is nil. Refer to the sum of lines 2 and 4.
- 5 As noted at Ex. L-A1-CCC-001, Attachment 1, Table 59, Note 5, the transfer of assets related to the DNNP facilities from OPG to DNNP LP resulted in income to OPG in the form of recapture of \$121.6M for SR&ED Qualifying Expenditures claimed previously (and credited in the Nuclear Development Variance Account; refer to line 3) for the DNNP facilities. As a result, the overall impact to the account from these deductions over 2023- 2025 is nil. Refer to the sum of lines 3 and 5.

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 1
Table 21

Table 21
Capacity Refurbishment Variance Account - Nuclear - PRP
Summary of Account Transactions - 2025 (\$M)

Line No.	Particulars	Note	Actual 2025
			(a)
	<u>Capital Addition to Variance Account:</u>		
1	Forecast Cost of Capital Amount		0.0
2	Actual Net Plant Rate Base Amount		0.0
3	Weighted Average Cost of Capital	1	5.92%
4	Actual Cost of Capital Amount (line 2 x 3)		0.0
5	Cost of Capital Variance (line 4 - line 1)		0.0
6	Forecast Depreciation		0.0
7	Actual Depreciation		0.0
8	Depreciation Variance (line 7 - line 6)		0.0
	<u>Income Tax Impact:</u>		
9	Forecast Capital Cost Allowance Deduction		0.0
10	Actual Capital Cost Allowance Deduction		2.4
11	Actual SR&ED Qualifying Expenditures		35.8
12	Difference (line 9 - line 10 - line 11)		(38.2)
13	Net Decrease in Regulatory Taxable Income	2	(38.2)
14	Income Tax Rate		25%
15	Income Tax Impact (line 13 x line 14/ (1 - line 14))		(12.7)
16	Capital Addition to Variance Account - PRP (line 5 + line 8 + line 15)		(12.7)
	<u>Non-Capital Addition to Variance Account:</u>		
17	Forecast Costs		0.0
18	Actual Costs	3	0.0
19	Difference (line 18 - line 17)		0.0
20	Non-Capital Addition to Variance Account - PRP (line 19)		0.0
21	Total Addition to Variance Account - PRP (line 16 + line 20)		(12.7)

Notes:

- Col. (a) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 14: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
- The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2025.
- Col. (a) as presented in Ex. L-A1-CCC-001, Attachment 1, Table 46, line 2, col. (f).

Table 2
Deferral and Variance Accounts
Continuity of Account Balances - Actual 2025 and 2026 (\$M):

Line No.	Account	Note	Actual Year End Balance 2025	Projected 2026					(a)+(b)+(c)+(d)+(e)+(f)
				Transactions	Amortization EB-2020-0290	Amortization EB-2023-0336	Interest	Transfers	Projected Year End Balance 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 2		Note 3	Note 4	Note 5		
	Hydroelectric:								
1	Hydroelectric Water Conditions Variance		(118.9)	(9.7)	0.0	39.9	(2.6)	0.0	(91.5)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(60.7)	4.0	0.0	4.8	(1.4)	0.0	(53.3)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	0.0	(0.0)	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		214.3	26.0	0.0	(115.8)	4.3	0.0	128.9
5	Income and Other Taxes Variance - Hydroelectric		(15.5)	(2.1)	0.0	4.6	(0.4)	0.0	(13.3)
6	Capacity Refurbishment Variance - Hydroelectric		218.9	78.8	0.0	(20.7)	6.3	0.0	283.3
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.3	1.7	0.0	(2.2)	0.2	0.0	7.9
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		8.3	0.0	(8.3)	0.0	0.0	0.0	0.0
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		8.8	0.0	(8.8)	0.0	0.0	0.0	0.0
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		(25.4)	(3.0)	0.0	(11.2)	0.0	0.0	(39.7)
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(75.5)	(16.4)	0.0	20.5	(1.9)	0.0	(73.3)
14	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	6	(12.4)	(5.9)	0.0	0.8	0.0	0.0	(17.6)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		18.4	4.2	0.0	(5.5)	0.5	0.0	17.5
16	Regulated Hydroelectric Subtotal		168.6	77.5	(17.1)	(84.9)	5.0	0.0	149.1
	Nuclear:								
17	Nuclear Liability Deferral		454.1	22.6	0.0	(75.3)	0.0	0.0	401.4
18	Nuclear Development Variance - DNNP		63.9	(2.3)	0.0	(43.3)	1.0	0.0	19.3
19	Nuclear Development Variance - Non-DNNP		64.2	136.4	0.0	0.0	3.4	0.0	204.0
20	Ancillary Services Net Revenue Variance - Nuclear		(10.0)	(3.3)	0.0	4.5	(0.2)	0.0	(9.1)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project		188.5	97.9	0.0	0.0	6.1	0.0	292.5
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP		160.2	20.5	0.0	(44.7)	3.8	0.0	139.8
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(10.0)	0.0	0.0	7.2	(0.2)	0.0	(2.9)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		40.1	0.0	0.0	(31.7)	0.6	0.0	9.0
25	Capacity Refurbishment Variance - Nuclear - PRP		(12.9)	(7.2)	0.0	0.0	(0.4)	0.0	(20.5)
26	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved		21.1	0.0	(21.1)	0.0	0.0	0.0	0.0
27	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2017 Additions		(191.1)	(83.2)	0.0	(0.7)	(5.9)	0.0	(281.0)
28	Income and Other Taxes Variance - Nuclear		(5.9)	0.0	0.0	3.7	(0.1)	0.0	(2.4)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(393.9)	27.0	0.0	49.0	0.0	0.0	(317.9)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		53.2	0.0	(53.2)	0.0	0.0	0.0	0.0
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved		55.6	0.0	(55.6)	0.0	0.0	0.0	0.0
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved		65.9	0.0	0.0	(65.9)	0.0	0.0	0.0
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(142.1)	0.0	0.0	106.9	(2.3)	0.0	(37.4)
36	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	6	(58.4)	(27.1)	0.0	4.8	0.0	0.0	(80.7)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(102.1)	(131.1)	0.0	23.2	(4.0)	0.0	(213.9)
38	Fitness for Duty Deferral	9	3.4	4.7	0.0	0.0	0.1	0.0	8.2
39	SR&ED ITC Variance		(40.5)	0.9	0.0	0.2	(1.0)	0.0	(40.4)
40	Rate Smoothing Deferral	8	702.1	0.0	0.0	0.0	25.6	0.0	727.7
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		42.5	0.0	0.0	(42.5)	0.0	0.0	0.0
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		84.1	0.0	0.0	18.0	0.0	0.0	102.1
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		12.0	15.0	0.0	0.0	0.0	0.0	27.0
44	Pickering Closure Costs Deferral	9	8.7	0.3	0.0	0.0	0.2	0.0	9.3
45	Clarington Corporate Campus Deferral		7.9	0.0	0.0	0.0	0.2	0.0	8.1
46	Pickering B Variance		349.1	(471.8)	0.0	0.0	2.9	0.0	(119.8)
47	Pickering B Refurbishment Project Variance	10,12	0.0	120.6	0.0	0.0	2.2	0.0	122.8
48	Nuclear Subtotal		1,409.9	(280.1)	(129.9)	(86.8)	32.0	0.0	945.2
49	Sale of Unprescribed Kipling Site Deferral		(7.5)	0.0	0.0	5.1	0.0	0.0	(2.5)
50	Total (line 16 + line 48 + line 49)	7	1,571.0	(202.6)	(147.0)	(166.6)	37.0	0.0	1,091.8
	DNNLP LP:								
51	Darlington New Nuclear Project Variance Account Re Capital Cost Amounts	11,12	0.0	112.0	0.0	0.0	2.0	0.0	114.0
52	Darlington New Nuclear Project Variance Account Re Development	11	0.0	8.5	0.0	0.0	0.1	0.0	8.6
53	DNNP Generator Capital Structure Variance	11	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1 Based on 2026 forecasts reflected in OPG's 2025-2031 Business Plan that underpins EB-2025-0297 pre-filed evidence.

2 From Ex. L-H1-Staff-260, Attachment 1, Table 1, col. (d).

3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (I) for Regulated Hydroelectric and App. D, Table 1, col. (I) for Nuclear.

4 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (i) for Regulated Hydroelectric and Table 2, col. (i) for Nuclear.

5 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account. For deferral and variance accounts that attract the OEB prescribed interest rate, a rate of 2.55% has been used, as published by the OEB as of Q2 2026.

6 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

7 The following accounts have a zero balance and no activity forecast during the period from January 1, 2023 to December 31, 2026 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, Earnings Sharing Deferral Account, and Darlington New Nuclear Project Variance Account.

8 Transactions in 2026 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

9 Account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements.

10 Established pursuant to amendment to *Ontario Regulation 53/05*, effective January 1, 2026.

11 Established pursuant to amendment to *Ontario Regulation 53/05*, subject to conditions set out in s.8 therein, effective January 1, 2026.

12 Transactions per Ex. I1-1-1, Table 6, line 7, col. (a) for line 51 and as per Ex. I1-1-1, Table 7, line 7, col. (a) for line 47.

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2022, 2023, 2024, 2025 and 2026 (\$M)¹

Line No.	Account	Note	Actual Year End Balance 2022	Actual Year End Balance 2023	Actual Year End Balance 2024	Actual Year End Balance 2025	Projected Year End Balance 2026
			(a)	(b)	(c)	(d)	(e)
			Note 2	Note 3	Note 4	Note 5	Note 6
	Regulated Hydroelectric:						
1	Hydroelectric Water Conditions Variance		(172.4)	(185.6)	(172.6)	(118.9)	(91.5)
2	Ancillary Services Net Revenue Variance - Hydroelectric		(34.3)	(31.5)	(22.2)	(60.7)	(53.3)
3	Hydroelectric Incentive Mechanism Variance		0.0	0.0	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance		401.8	393.3	305.6	214.3	128.9
5	Income and Other Taxes Variance - Hydroelectric		(13.3)	(17.3)	(17.3)	(15.5)	(13.3)
6	Capacity Refurbishment Variance - Hydroelectric		80.4	95.7	162.1	218.9	283.3
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance		8.0	8.8	8.6	8.3	7.9
8	Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)		2.1	1.1	0.0	0.0	0.0
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved		33.0	24.8	16.5	8.3	0.0
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved		14.0	7.0	0.0	0.0	0.0
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved		35.3	26.5	17.7	8.8	0.0
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions		28.1	8.4	(8.0)	(25.4)	(39.7)
13	Pension & OPEB Cash Payment Variance - Hydroelectric		(77.0)	(83.5)	(76.3)	(75.5)	(73.3)
14	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric	7	(2.0)	(4.9)	(8.5)	(12.4)	(17.6)
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance		16.1	17.3	16.7	18.4	17.5
16	Regulated Hydroelectric Subtotal		319.9	260.0	222.3	168.5	149.1
	Nuclear:						
17	Nuclear Liability Deferral		188.3	377.5	527.3	454.1	401.4
18	Nuclear Development Variance - DNNP		110.9	106.7	61.8	63.9	19.3
19	Nuclear Development Variance - Non-DNNP		0.0	7.8	23.5	64.2	204.0
20	Ancillary Services Net Revenue Variance - Nuclear		(13.6)	(15.1)	(13.5)	(10.0)	(9.1)
21	Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project		(47.6)	121.4	170.2	188.5	292.5
22	Capacity Refurbishment Variance - Nuclear - Non-DRP/Non-PRP		49.7	146.5	173.7	160.2	139.8
23	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved		(30.9)	(25.8)	(16.8)	(10.0)	(2.9)
24	Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved		79.4	83.3	70.1	40.1	9.0
25	Capacity Refurbishment Variance - Nuclear - PRP		0.0	0.0	0.0	(12.9)	(20.5)
26	Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved		84.2	63.2	42.1	21.1	0.0
27	Bruce Lease Net Revenues Variance - Post 2017 Additions		17.1	(4.2)	(102.0)	(191.1)	(281.0)
28	Income and Other Taxes Variance - Nuclear		(18.8)	(15.6)	(9.5)	(5.9)	(2.4)
29	Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)		42.9	21.5	0.0	0.0	0.0
30	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions		(122.6)	(341.3)	(411.1)	(393.9)	(317.9)
31	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved		212.8	159.6	106.4	53.2	0.0
32	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved		88.2	44.1	0.0	0.0	0.0
33	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290		222.5	166.9	111.3	55.6	0.0
34	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336		164.8	164.8	131.9	65.9	0.0
35	Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved		(383.4)	(342.1)	(244.4)	(142.1)	(37.4)
36	Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear	7	(12.3)	(26.9)	(42.1)	(58.4)	(80.7)
37	Nuclear Deferral and Variance Over/Under Recovery Variance		(74.7)	(76.5)	(61.5)	(102.1)	(213.9)
38	Fitness for Duty Deferral		1.6	2.0	2.5	3.4	8.2
39	SR&ED ITC Variance		(8.6)	(23.3)	(25.7)	(40.5)	(40.4)
40	Rate Smoothing Deferral		568.9	653.8	677.4	702.1	727.7
41	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved		(57.5)	24.4	85.1	42.5	0.0
42	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020		(45.0)	9.6	66.1	84.1	102.1
43	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023		0.0	0.0	(2.3)	12.0	27.0
44	Pickering Closure Costs Deferral		2.8	6.4	7.6	8.7	9.3
45	Clarington Corporate Campus Deferral		0.0	7.3	7.7	7.9	8.1
46	Pickering B Variance	8	0.0	26.5	131.1	349.1	(119.8)
47	Pickering B Refurbishment Project Variance	10	0.0	0.0	0.0	0.0	122.8
48	Nuclear Subtotal		1,019.1	1,322.3	1,466.8	1,409.9	945.2
49	Sale of Unprescribed Kipling Site Deferral		0.0	(15.1)	(12.6)	(7.5)	(2.5)
50	Total (line 16 + line 48 + line 49)	9	1,338.9	1,567.1	1,676.5	1,570.9	1,091.8
	DNNLP LP:						
51	Darlington New Nuclear Project Variance Account Re Capital Cost Amounts	11	0.0	0.0	0.0	0.0	114.0
52	Darlington New Nuclear Project Variance Account Re Development	11	0.0	0.0	0.0	0.0	8.6
53	DNNP Generator Capital Structure Variance	11	0.0	0.0	0.0	0.0	0.0

Notes:

1 Based on 2026 forecasts reflected in the 2025-2031 Business Plan that underpins EB-2025-0297 pre-filed evidence.

2 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.

3 From Ex. H1-1-1, Table 1a, col. (h).

4 From Ex. H1-1-1, Table 1b, col. (g).

5 From Ex. L-H1-Staff-260, Attachment 1, Table 1c, col. (g).

6 From Ex. L-H1-Staff-260, Attachment 2, Table 2, col. (g).

7 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

8 Established by *Ontario Regulation 53/05*, effective January 1, 2023 and as amended effective July 1, 2025.

9 The following accounts have a zero balance and no activity forecast during the period from January 1, 2023 to December 31, 2026 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, Earnings Sharing Deferral Account, and Darlington New Nuclear Project Variance Account.

10 Established pursuant to amendment to *Ontario Regulation 53/05*, effective January 1, 2026.

11 Established pursuant to amendment to *Ontario Regulation 53/05*, subject to conditions set out in s.8 therein, effective January 1, 2026.

Numbers may not add due to rounding.

Filed: 2026-05-20
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 3
Table 1

Table 1
Capacity Refurbishment Variance Account - Hydroelectric - Capital Projects In-service Prior to June 1, 2017 and Non-Capital Portion
Summary of Account Transactions - 2022, 2023, 2024, 2025 and 2026 (\$M)

Line No.	Particulars	Notes	Actual 2022	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)
	<u>Capital Addition to Variance Account:</u>						
1	Forecast Cost of Capital Amount	1	4.0	4.0	4.0	4.0	4.0
2	Actual Net Plant Rate Base Amount	2	104.9	102.9	100.8	98.8	96.7
3	Weighted Average Cost of Capital	3	6.85%	6.85%	6.85%	6.85%	6.85%
4	Actual Cost of Capital Amount (line 2 x line 3)		7.2	7.0	6.9	6.8	6.6
5	Cost of Capital Variance (line 4 - line 1)		3.2	3.0	2.9	2.8	2.6
6	Forecast Depreciation	1	1.2	1.2	1.2	1.2	1.2
7	Actual Depreciation	2	2.1	2.1	2.1	2.1	2.1
8	Depreciation Variance (line 7 - line 6)		0.9	0.9	0.9	0.9	0.9
	Income Tax Impact						
9	Forecast Capital Cost Allowance Deduction	1	3.5	3.5	3.5	3.5	3.5
10	Actual Capital Cost Allowance Deduction		4.0	3.7	3.5	3.3	3.2
11	Difference (line 9 - line 10)		(0.4)	(0.2)	0.0	0.2	0.4
12	Net Increase in Regulatory Taxable Income	4	2.4	2.6	2.7	2.8	2.9
13	Income Tax Rate		25.0%	25.0%	25.0%	25.0%	25.0%
14	Income Tax Impact (line 12 x line 13 / (1 - line 13))		0.8	0.9	0.9	0.9	1.0
15	Addition to Variance Account - Capital Portion - Projects In-service Prior to June 1, 2017 (line 5 + line 8 + line 14)		4.9	4.8	4.7	4.6	4.5
	<u>Non-Capital Addition to Variance Account:</u>						
16	Forecast Non-Capital Costs	5	0.1	0.1	0.1	0.1	0.1
17	Actual Non-Capital Costs	6	5.6	3.6	4.9	14.8	9.4
18	Total Addition to Variance Account - Non-Capital Portion (line 17 - line 16)		5.5	3.5	4.8	14.8	9.4

For notes see Table 1a.

Numbers may not add due to rounding.

Filed: 2026-05-20
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 3
Table 1a

Table 1a
Notes to Table 1

Capacity Refurbishment Variance Account - Hydroelectric - Capital Projects In-service Prior to June 1, 2017 and Non-Capital Portion (\$M)

Notes:

- 1 From EB-2023-0336, Ex. H1-1-1, Table 7a, Note 1, col. (c), lines 3a, 5a, and 6a for forecast cost of capital, depreciation and capital cost allowance deduction, respectively.
- 2 For cols. (a) to (e), the amounts are calculated as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for Hydroelectric Projects In-Service Prior to June 1, 2017 (\$M)					
Line No.		2022 Actual	2023 Actual	2024 Actual	2025 Actual
		(a)	(b)	(c)	(d)
1b	Gross Plant Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 7a, line 4b, col. (h))	123.1	123.1	123.1	123.1
2b	In-service Additions	0.0	0.0	0.0	0.0
3b	Gross Plant Closing Balance (line 1b + 2b)	123.1	123.1	123.1	123.1
4b	Gross Plant Rate Base Amount (line 1b + 3b)/2	123.1	123.1	123.1	123.1
5b	Accumulated Depreciation Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 7a, line 8b, col. (h))	17.2	19.2	21.3	23.3
6b	Depreciation	2.1	2.1	2.1	2.1
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b)	19.2	21.3	23.3	25.4
8b	Accumulated Depreciation Rate Base Amount ((line 5b + 7b)/2)	18.2	20.2	22.3	24.3
9b	Net Plant Rate Base Amount (line 4b - line 8b)	104.9	102.9	100.8	98.8

- 3 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).
- 4 The change in regulatory taxable income is calculated as the sum of lines 8 and 11, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to the difference between (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 9.30%, and (ii) EB-2023-0336, Ex. H1-1-1, Table 7a, line 4a, col. (c).
- 5 EB-2016-0152, Ex. J20.6.
- 6 The actual non-capital amounts in cols. (a) to (e) comprise the following:

Table to Note 6 - Capacity Refurbishment Variance Account - Actual Non-Capital Costs for Hydroelectric Projects (\$M)						
Line No.	Project Number	Project Name	2022 Actual	2023 Actual	2024 Actual	2025 Actual
			(a)	(b)	(c)	(d)
1c	82986	R.H. Saunders Generating Station – Replacement of Westinghouse Excitation	0.2	0.2	0.1	
2c	83155	Abitibi Canyon Generating Station – G2 Capital Upgrades/HG	0.6			
3c	80980	Barrett Chute Generating Station – Rewind Generators & Reinsulate Field Poles (G1-4) First Unit (G3)	0.1			
4c	82246	Otter Rapids Generating Station – Sluice Gate Upgrades	0.3	0.2	0.2	
5c	82372	Silver Falls Generating Station – Exciter Replacement	0.1			
6c	82385	Silver Falls Generating Station – G1 Rewind and New Core	1.1			
7c	84385	Otto Holden Generating Station – Capital Project Scope G7 1st Unit	0.2			
8c	82392	Silver Falls Generating Station – Turbine Upgrade	0.1			
9c	82089	Calabogie Generating Station Redevelopment	1.7			
10c	84286	Abitibi Canyon Generating Station – G3 Stator Winding		0.7		
11c	84285	Abitibi Canyon Generating Station – G4 Stator Winding		0.7		
12c	84558	DeCew Falls II Generating Station – G1 Runner Shaft Replacement		0.4	0.7	
13c	86480	Otto Holden Generating Station – G5 Refurbishment - Turbine & Generator		0.2		
14c	84494	Chenaux Generating Station – Limerick Isl. Spr Structure Sluice Gate Hoist	1.1	1.1		
15c	84587	Barrett Chute Generating Station – Capital Refurb Rewind Generators & Reinsulate Field Poles (G1-4) Second Unit (G4)	0.1			
16c	83194	Frederick House Lake Dam Upgrades		0.0	1.4	0.1
17c	87192	Abitibi Canyon Generating Station – Canyon Dam Downstream Concrete Rehab			0.0	0.0
18c	86082	Barrett Chute Generating Station – Capital Refurb Rewind Generators & Reinsulate Field Poles (G1)			0.1	
19c	82543	Otter Rapids Generating Station – G2 Capital Upgrade			1.0	
20c	83495	R.H. Saunders Generating Station – G9 Capital Refurbishment			0.7	0.3
21c	82087	Coniston/Stinson Generating Station Redevelopment				3.4
22c	86077	Barrett Chute Generating Station – Capital Refurb Rewind Generators & Reinsulate Field Poles (G2)				0.1
23c	86383	Aguasabon Generating Station – G2 Rewind & Core Replacement				0.1
24c	86477	Otto Holden Generating Station – G8 Refurb - Turbine & Generator				0.2
25c	86386	Kakabeka Falls Generating Station Redevelopment				4.7
26c	86387	Matabitchuan Generating Station Redevelopment				0.2
27c	86478	Otto Holden Generating Station - G6 Refurb - Turbine & Generator				
28c	82542	Otter Rapids Generating Station - G1 Capital Upgrade				
29c	83104	R.H. Saunders Generating Station – Runner Replacement				
30c	86587	R.H. Saunders Generating Station – G12 Capital Refurbishment				
31c	89505	Abitibi Canyon Generating Station – Abitibi Canyon Concrete Repair Zone 7				
32c	83257	Cameron Falls Generating Station - G7 Capital Refurb				
33c		Small Hydro Redevelopment			0.6	5.5
34c		Total*	5.6	3.6	4.9	14.8

*Where applicable, reflects life to date non-capital costs incurred prior to 2022 in connection with the identified projects.

Table 1b
Capacity Refurbishment Variance Account - Hydroelectric - Projects In-service from June 1, 2017 to December 31, 2021
Summary of Account Transactions - 2022, 2023, 2024, 2025 and 2026 (\$M)

Line No.	Particulars	Note	Actual 2022	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)
1	Actual Net Plant Rate Base Amount	1	174.9	170.2	165.5	160.8	156.1
2	Weighted Average Cost of Capital	2	6.85%	6.85%	6.85%	6.85%	6.85%
3	Cost of Capital (line 1 x line 2)		12.0	11.7	11.3	11.0	10.7
4	Actual Depreciation	1	4.7	4.7	4.7	4.7	4.7
	Income Tax Impact						
5	Actual Capital Cost Allowance Deduction	3	10.1	8.6	7.6	6.8	6.1
6	Actual SR&ED Qualifying Capital Expenditures		4.3	0.0	0.0	0.0	0.0
7	Net (Decrease) Increase in Regulatory Taxable Income	4	(2.4)	3.2	4.0	4.7	5.1
8	Income Tax Rate		25.0%	25.0%	25.0%	25.0%	25.0%
9	Income Tax Impact (line 7 x line 8 / (1 - line 8))		(0.8)	1.1	1.3	1.6	1.7
10	Addition to Variance Account - Capital Portion - Projects In-service from June 1, 2017 to December 31, 2021 (line 3 + line 4 + line 9)		15.9	17.4	17.4	17.3	17.1

Notes:
1 For cols. (a) to (e), the amounts are calculated as follows:

Line No.		2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget
		(a)	(b)	(c)	(d)	(e)
1a	Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 7c, line 4a, col. (e))	177.2	172.5	167.8	163.1	158.4
2a	In-service additions	0.0	0.0	0.0	0.0	0.0
3a	Depreciation*	4.7	4.7	4.7	4.7	4.7
4a	Closing Balance (line 1a + line 2a - line 3a)	172.5	167.8	163.1	158.4	153.7
5a	Net Plant Rate Base Amount (line 1a + line 4a)/2	174.9	170.2	165.5	160.8	156.1

*

Represents the ongoing depreciation impact of recoverable amounts in respect of the EB-2023-0336 CRVA approved projects, determined in a manner consistent with EB-2023-0336, Ex. H1-1-1, Table 7c, line 7.

2 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).

3 Represents the ongoing CCA impact of recoverable amounts in respect of the EB-2023-0336 CRVA approved projects, determined in a manner consistent with EB-2023-0336, Ex. H1-1-1, Table 7c, line 8.

4 The change in regulatory taxable income is calculated as line 4, less the sum of lines 5 and 6, plus the ROE component of the cost of capital at line 3. The ROE component is equal to line 1 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 9.30%.

Numbers may not add due to rounding.

Table 1c
Capacity Refurbishment Variance Account - Hydroelectric - Projects In-service from January 1, 2022 - December 31, 2026
Summary of Account Transactions Before Application of Recoverability Threshold - 2022, 2023, 2024, 2025 and 2026 (\$M)

Line No.	Particulars	Note	Actual 2022	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)
1	Actual Net Plant Rate Base	4	161.4	404.1	494.5	623.7	886.4
2	Weighted Average Cost of Capital	1	6.85%	6.85%	6.85%	6.85%	6.85%
3	Cost of Capital (line 1 x line 2)		11.1	27.7	33.9	42.7	60.7
4	Actual Depreciation	4	3.0	7.9	9.5	12.0	15.8
	Income Tax Impact						
5	Actual Capital Cost Allowance Deduction		43.3	141.4	21.4	44.4	113.5
6	Actual SR&ED Qualifying Capital Expenditures		19.3	18.6	3.4	36.7	22.4
7	Net (Decrease) Increase in Regulatory Taxable Income	3	(52.8)	(135.2)	5.4	(43.0)	(83.0)
8	Income Tax Rate		25.0%	25.0%	25.0%	25.0%	25.0%
9	Income Tax Impact (line 7 x line 8 / (1 - line 8))		(17.6)	(45.1)	1.8	(14.3)	(27.7)
10	Total Capital-Related Revenue Requirement (line 3 + line 4 + line 9)		(3.5)	(9.5)	45.2	40.4	48.8
11	Less: EB-2020-0290 Reference Amount	2	1.0	1.0	1.0	1.0	1.0
12	Total Capital Addition to Variance Account - Capital Portion - Projects In-service from January 1, 2022 to December 31, 2026, Before Application of Recoverability Threshold (line 10- line 11)	5	(4.5)	(10.5)	44.2	39.4	47.9

- Notes:
- 1 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).
 - 2 Per EB-2020-0290 Payment Amounts Order, App. E, pp. 8-9.
 - 3 The change in regulatory taxable income is calculated as line 4, less the sum of 5 and 6, plus the ROE component of the cost of capital at line 3. The ROE component is equal to line 1 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 9.30%.
 - 4 For cols. (a) to (d), the amounts are calculated as follows:

Table to Note 4 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for Hydroelectric Projects In-Service from Jan 1, 2022 to Dec 31, 2025 (\$M)						
Line No.		Actual 2022	Actual 2023	Actual 2024	Actual 2025	
		(a)	(b)	(c)	(d)	
1a	Gross Plant Opening Balance	0.0	364.1	458.1	562.2	
2a	In-service Additions**	364.1	94.0	104.0	229.9	
3a	Gross Plant Closing Balance (line 1a + line 2a)	364.1	458.1	562.2	792.1	
4a	Gross Plant Rate Base Amount (line 1a + line 3a)/2*	163.0	411.1	510.2	650.1	
5a	Accumulated Depreciation Opening Balance	0.0	3.0	10.9	20.4	
6a	Depreciation	3.0	7.9	9.5	12.0	
7a	Accumulated Depreciation Closing Balance (line 5a + line 6a)	3.0	10.9	20.4	32.4	
8a	Accumulated Depreciation Rate Base Amount (line 5a + line 7a)/2	1.5	7.0	15.7	26.4	
9a	Net Plant Rate Base Amount (line 4a - line 8a)	161.4	404.1	494.5	623.7	

* Total in-service additions include the following amounts over \$50M: 2022 - \$76.4M for Calabogie GS - Redevelopment as per Ex. B2-3-1, Table 2a, Note 1 and 2025 - \$59.0M for Otter G2 Capital Upgrade as per Ex. L-A1-CCC-001, Att. 1, Table 3, Note 1. For these in-service additions, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

** The following projects comprise the actual in-service additions from 2022-2025.

Table to Note ** - Capacity Refurbishment Variance Account - Hydroelectric - In-Service Capital Project Listing from January 1, 2022 to December 31, 2025 (\$M)						
Line No.	Project Number	Project Name	Actual In-Service 2022	Actual In-Service 2023	Actual In-Service 2024	Actual In-Service 2025
			(a)	(b)	(c)	(d)
1b	83155	Abitibi Canyon Generating Station – G2 Capital Upgrades/HG	29.2			0.3
2b	80980	Barrett Chute Generating Station – Rewind Generators & Reinsulate Field Poles (G1-4) First Unit (G3)	13.3	0.3	0.0	
3b	82385	Silver Falls Generating Station – G1 Rewind and New Core	20.0		0.3	
4b	84385	Otto Holden Generating Station – Capital Project Scope G7 1st Unit	11.7	0.5	0.1	
5b	82392	Silver Falls Turbine Upgrade	8.6			0.0
6b	82986	R.H. Saunders Generating Station – Replacement of Westinghouse Excitation*	4.2	2.2	0.7	
7b	83610	Aguasabon Generating Station – Surge Tank Replacement*	1.3	0.1		
8b	84185	Sir Adam Beck I Generating Station – Units G1, G2 Replacement*	98.3	2.9		
9b	80581	Ranney Falls Generating Station G3*	18.5	2.3		
10b	82089	Calabogie Generating Station Redevelopment	133.1	30.8	1.8	(0.1)
11b	82246	Otter Rapids Generating Station – Sluice Gate Upgrades	11.6	7.1	3.5	
12b	82372	Silver Falls Generating Station – Exciter Replacement	1.7		(0.0)	
13b	84494	Chenault Generating Station – Limerick Island Superstructure Sluice Gate Hoist	12.3	12.5		
14b	84285	Abitibi Canyon Generating Station – G4 Stator Winding		8.2		
15b	86480	Otto Holden Generating Station – G5 Refurb - Turbine & Generator		7.7	1.2	
16b	82543	Otter Rapids Generating Station – G2 Capital Upgrade		6.1	1.3	59.0
17b	84587	Barrett Chute Generating Station – Capital Refurb Rewind Generators & Reinsulate Field Poles (G1-4) Second Unit (G4)		11.7	0.1	
18b	83194	Frederick House Lake Dam Upgrades			35.3	39.1
19b	87192	Abitibi Canyon Generating Station – Canyon Dam Downstream Concrete Rehab			21.1	3.0
20b	89505	Abitibi Canyon Generating Station – Concrete Repair Zone 7			1.4	21.5
21b	84286	Abitibi Canyon Generating Station – G3 Stator Winding			8.4	0.3
22b	84558	DeCew Falls II Generating Station – G1 Runner Shaft Replacement			17.4	1.3
23b	86082	Barrett Chute Generating Station – Capital Refurb Rewind Generators & Reinsulate Field Poles (G1)			10.6	
24b	80684	Otter Rapids Generating Station – Runner Purchase				4.2
25b	83104	R.H. Saunders Generating Station – Runner Replacement				10.0
26b	83495	R.H. Saunders Generating Station – G9 Capital Refurbishment				35.1
27b	86383	Aguasabon Generating Station – G2 Rewind & Core Replacement				16.2
28b	86477	Otto Holden Generating Station – G8 Refurb - Turbine & Generator				12.0
29b	86077	Barrett Chute Generating Station – G2 Capital Refurb Rewind Generators & Reinsulate Field Poles				10.5
30b	86386	Kakabeka Falls Generating Station Redevelopment				12.5
31b	86387	Matabitchuan Generating Station Redevelopment				4.2
32b		EB-2023-0336 CRVA Approved Projects - Close Out Costs	0.3	1.5	0.8	0.9
33b		Total	364.1	94.0	104.0	229.9

- + Project was partially placed into service between June 1, 2017 to December 31, 2021 and formed part of the hydroelectric CRVA balance approved for recovery in EB-2023-0336.
- 5 The minor differences between the account transactions presented in EB-2023-0336, Ex. H1-1-1, Table 1c for 2022 and in Ex. L-H1-Staff-260, Attachment 1, Tables 1a, 1b and 1c for each of 2023, 2024 and 2025, and the total annual transactions for the respective years per Ex. L-H1-Staff-260, Attachment 3 reflect self-correcting interperiod adjustments that offset to nil as of year-end 2025.

Table 1d
Capacity Refurbishment Variance Account - Hydroelectric - Projects In-service from January 1, 2022 to December 31, 2026
Revenue Requirement Impact of Differences Between Total In-Service Additions and Capital Funding Implicit in Payment Amounts (\$M)

Line No.	Particulars	Note	Actual 2022	Actual 2023	Actual 2024	Actual 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)
1	Capital Funding Implicit in Payment Amounts	3	153.0	153.0	153.0	153.0	153.0
2	Total Actual In-Service Additions	6	524.8	269.4	349.0	392.7	532.9
3	Difference Between Total Actual In-Service Additions and Capital Funding Implicit in Payment Amounts (line 2 - line 1)		371.8	116.4	196.0	239.7	379.9
4	Actual Net Plant Rate Base Amount	2	184.3	423.2	569.7	772.8	1,062.1
5	Weighted Average Cost of Capital	1	6.85%	6.85%	6.85%	6.85%	6.85%
6	Cost of Capital (line 4 x line 5)		12.6	29.0	39.0	52.9	72.8
7	Actual Depreciation	2	3.2	7.1	12.2	17.5	23.4
	Income Tax Impact						
8	Actual Capital Cost Allowance Deduction	5	130.8	62.2	46.6	71.5	153.7
9	Actual SR&ED Qualifying Capital Expenditures	5	18.2	5.8	14.0	15.3	17.8
10	Net (Decrease) Increase in Regulatory Taxable Income	4	(138.0)	(43.2)	(24.6)	(37.0)	(103.7)
11	Income Tax Rate		25.0%	25.0%	25.0%	25.0%	25.0%
12	Income Tax Impact (line 10 x line 11 / (1 - line 11))		(46.0)	(14.4)	(8.2)	(12.3)	(34.6)
13	Revenue Requirement Impact of Difference Between Total Actual In-Service Additions and Capital Funding Implicit in Payment Amounts (line 6 + line 7 + line 12)		(30.2)	21.7	43.0	58.1	61.6

- Notes:
- 1 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).
- 2 For cols. (a) to (e), the amounts are calculated as follows:

Table to Note 2 - Net Plant Rate Base Amounts for Differences Between Total In-Service Additions And Capital Funding Implicit in Payment Amounts for Regulated Hydroelectric Projects (\$M)							Budget 2026
Line No.		Actual 2022	Actual 2023	Actual 2024	Actual 2025		
		(a)	(b)	(c)	(d)		(e)
1a	Opening Balance	0.0	368.6	477.8	661.7		883.9
2a	In-service additions (line 3)	371.8	116.4	196.0	239.7		379.9
3a	Depreciation*	3.2	7.1	12.2	17.5		23.4
4a	Closing Balance (line 1a + line 2a - line 3a)	368.6	477.8	661.7	883.9		1,240.4
5a	Net Plant Rate Base Amount (line 1a + line 4a)/2	184.3	423.2	569.7	772.8		1,062.1

* Calculated as the difference between: (i) actual/budget depreciation of total regulated hydroelectric in-service additions each year, and (ii) estimated depreciation of capital funding implicit in payment amounts each year. The amount in (ii) is calculated as follows: a proportion of the corresponding year's amount in (i) multiplied by the ratio of the implicit funding (line 1) to the total in-service additions (line 2), plus the amount in (ii) for the preceding year.

3 Per EB-2020-0290 Payment Amounts Order, App. E, pp. 8-9.

4 The change in regulatory taxable income is calculated as line 7, less the sum of lines 8 and 9, plus the ROE component of the cost of capital at line 6. The ROE component is equal to line 4 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 9.30%.

5 Calculated as the difference between: (i) actual CCA deductions and SR&ED qualifying capital expenditures for total cumulative regulated hydroelectric in-service additions for the 2022-2026 period, and (ii) estimated CCA deductions and SR&ED qualifying capital expenditures related to the cumulative capital funding implicit in payment amounts for the 2022-2026 period. The amount in (ii) is calculated based on the corresponding year's average CCA and SR&ED qualifying capital expenditure rates derived as a proportion of (i) to the underlying tax balances for the total in-service additions.

6 Cols. (a), (b), and (c) per Ex. B2-3-1, Table 2, col. (b), lines 12, 16, and 20. Col. (d) per Ex. L-A1-CCC-001, Att. 1, Table 3, line 4, col. (b). Col. (e) per Ex. B2-3-1, Table 3, line 8, col. (b).

Numbers may not add due to rounding.

Filed: 2026-05-20
EB-2025-0297
Exhibit L
H1-Staff-260
Attachment 3
Table 1e

Table 1e
Capacity Refurbishment Variance Account - Hydroelectric - Projects In-service from January 1, 2022 to December 31, 2026
Summary of Account Transactions - 2022, 2023, 2024, 2025 and 2026 (\$M)

Line No.	Particulars	Note	Actual 2022	Actual 2023	Actual 2024	Actual 2025
			(a)	(b)	(c)	(d)
	<u>Capital Addition to Variance Account:</u>					
1	Capital Addition to Variance Account Before Application of Recoverability Threshold	1	(4.5)	(10.5)	44.2	39.4
2	Revenue Requirement Impact of Difference Between Total Actual In-Service Additions and Capital Funding Implicit in Payment Amounts	2	(30.2)	21.7	43.0	58.1
3	Total Addition to Variance Account - Capital Portion - Projects In-Service from January 1, 2022 to December 31, 2026 (col. (f): lesser of line 1 and line 2; cols. (a) - (e): line 1 or line 2 corresponding to col.(f))		(4.5)	(10.5)	44.2	39.4

Budget 2026	(a)+(b)+(c)+(d)+(e) Total
(e)	(f)
47.9	116.4
61.6	154.2
47.9	116.4

Notes:
1 From Attachment 3, Table 1c, line 12.
2 From Attachment 3, Table 1d, line 13.

Board Staff Interrogatory #261

Interrogatory

Reference:

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 51, 52, and 70

Ref 2: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement, Exhibit 0 / Tab 1 / Schedule 1 / p. 29, July 16, 2021

Preamble:

OPG stated that the Impact for International Financial Reporting Standard (IFRS) Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record financial impacts of transition to and implementation of IFRS from US Generally Accepted Accounting Principles (GAAP) in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the *Securities Act* (Ontario). To date, no entries have been recorded in this account as OPG has continued to apply US GAAP to report its consolidated financial statements.

OPG stated that it proposes to continue the deferral account as of the effective date of the payment amounts order in this proceeding and as necessary to reassess this matter in the next payment amounts proceeding.

OPG noted that no interest is recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

A similar Impact for IFRS Deferral Account is also being proposed for DNNP LP. DNNP LP proposes to record no interest on the balance of such account.

Question(s):

- a) Please confirm that OPG and DNNP LP will record the revenue requirement impacts of the transition to and implementation of IFRS from US GAAP, and not solely the “financial impacts”. If this is not the case, please explain.
- b) Please provide more detail as to what OPG and DNNP LP propose to record in the Impact for IFRS Deferral Accounts, for example, capitalization impacts, pension and Other-Post Employment Benefits (OPEB) impacts, and decommissioning liabilities impacts.

Response

a) The Applicants' proposal with respect to the scope of the respective Impact for IFRS Deferral Accounts is for the accounts to have the same scope as approved by the OEB for OPG through the EB-2020-0290 settlement proposal. That scope was established by reference to "financial impacts of transition and implementation of IFRS from US GAAP"¹ and is consistent with the scope of OPG's analogous account, the Impact for US GAAP Deferral Account, approved by the OEB in EB-2011-0432 in view of OPG's then upcoming adoption of US GAAP from the legacy Canadian GAAP.²

The use of the term "financial impacts" is deliberate, as it was in EB-2011-0432. Specifically, the transition to a new set of accounting standards, whether from legacy Canadian GAAP to US GAAP, or from US GAAP to IFRS, typically entails some form of retrospective application such that there are opening balance sheet adjustments recorded directly to retained earnings or accumulated other comprehensive income that would have otherwise been charged through the income statement, and if applicable captured in the revenue requirement, over future periods. To have the ability to evaluate the appropriate regulatory treatment of any such transition adjustments, they need to be captured in a deferral account in order to avoid the risk of being considered an out-of-period item. In establishing the Impact for US GAAP Deferral Account in EB-2011-0432 prior to OPG having actually incurred the impacts of the transition to US GAAP, the OEB recognized this risk and agreed that it was appropriate to make provisions addressing it:

If the proposed deferral account is not approved, the financial impact could be characterized as an out-of-period cost. In order to make provision so that any balances arising from the transition and implementation of USGAAP may be eligible for recovery, it is appropriate to approve the establishment of the account at this time, even though there is no immediate rate impact.³

Whether the disposition of any opening balance sheet adjustments recorded in the account would ultimately give rise to revenue requirement impacts will be dependent on the OEB's decision with respect to such disposition. Therefore, to ensure that the account is able to capture the transition adjustments, the Applicants believe it is appropriate to refer to the amounts recordable in the account as "financial impacts" rather than "revenue requirements impacts." For clarity, the account would capture, as applicable, not only these transition impacts but any

¹ EB-2020-0290 Decision and Order, November 15, 2021, Schedule A, p. 29.

² EB-2011-0432, Decision and Order, March 2, 2012, p. 5.

³ *Ibid.*

1 ongoing variances resulting from these opening balance sheet adjustments, all for
2 future review and disposition by the OEB.

3
4 b) The Applicants have not evaluated a list of potential impacts that they may record
5 in the respective Impact for IFRS Deferral Account in the event they transition to
6 IFRS during the IR term. However, OPG generally expects that the most significant
7 impacts for recording in the account would be consistent with the areas previously
8 identified by OPG in EB-2012-0002, which includes:

- 9 • the treatment of actuarial gains and losses and past service costs associated
10 with OPG's pension and other post-employment benefit ("OPEB") plans; and
- 11 • the treatment of OPG's nuclear facilities decommissioning and nuclear
12 waste management liabilities, including differences arising upon accounting
13 recognition of changes in the estimates for these liabilities.

Board Staff Interrogatory #262

Interrogatory

Reference:

Ref 1: EB-2024-0136, OEB Letter, Updated Filing Requirements for Ontario Power Generation Inc., September 17, 2024

Ref 2: Exhibit D4 / Tab 1 / Schedule 1 / p. 1

Preamble:

The OEB noted that at the time of issuing its September 17, 2024 letter, OPG is required by regulation to do its financial reporting under US Generally Accepted Accounting Principles (GAAP).

The OEB also stated that while there is no corresponding requirement for the OEB to set OPG's payments based on US GAAP, to do otherwise would be a significant administrative burden.

The OEB said that it will set payments based on US GAAP, but will consider the appropriate approach to capitalizing indirect overheads that would not be permitted to be capitalized under International Financial Reporting Standard (IFRS).

The final Filing Requirements removed the proposed reference to a transition to IFRS and included the requirement for OPG to file a plan for transitioning away from capitalizing indirect overheads or provide a justification for maintaining current practice. Depending on the OEB's determination on the capitalization of indirect overheads, the OEB noted that this issue could persist beyond the next payments application.

In the current application, OPG stated that "overhead costs that are only directly attributable to the acquisition or construction of a capital asset are capitalized."

Question(s):

- a) Please confirm that OPG does not capitalize indirect overheads and no such amounts are included in OPG's requested rate base amounts.
- b) If OPG does capitalize indirect overheads, please quantify and explain.
- c) Please provide a justification for OPG to maintain its current practice of using US GAAP for regulatory purposes, also given that there could be other impacts between US GAAP and IFRS (and not solely indirect overhead differences).

Response

a) Confirmed.

b) Not applicable.

c) OPG's use of US GAAP for regulatory purposes in this proceeding is consistent with the OEB's approval for OPG to use US GAAP for regulatory accounting, reporting and rate-making purposes in EB-2012-0002¹ and the OEB's continued acceptance thereof in all subsequent OPG proceedings, and accords to the OEB's current filing requirements. As noted by the OEB (see below), this also avoids a significant administrative burden of using IFRS for regulatory purposes while using US GAAP for financial reporting.

Specifically, the OEB's current filing requirements state that OPG's "filing should be made in accordance with United States Generally Accepted Accounting Principles". (Filing Requirements for Ontario Power Generation Inc., September 17, 2024, p. 6). This reflects the following findings by the OEB in the EB-2024-0136 consultation that determined these requirements (OEB Letter, September 17, 2024, pp. 3-4):

Staff had proposed a new section to the Filing Requirements on the transition to IFRS and the approach to capitalizing overheads. At this time, OPG is required by regulation to do its financial reporting under United States Generally Accepted Accounting Principles (USGAAP). While there is no corresponding requirement for the OEB to set OPG's payments based on USGAAP, to do otherwise would be a significant administrative burden. The OEB will therefore set payments based on USGAAP but will consider the appropriate approach to capitalizing indirect overheads that would not be permitted to be capitalized under International Financial Reporting Standards (IFRS).

OPG has not otherwise reevaluated the justification for using US GAAP for regulatory purposes.

¹ EB-2012-0002, Tr. Vol 1 Settlement Proposal, p. 25, lines 22-26.

Board Staff Interrogatory #263

Interrogatory

Reference:

Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / pp. 1 & 2

Preamble:

OPG stated that as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario) (O. Reg. 395/11), its consolidated financial statements are prepared in accordance with US Generally Accepted Accounting Principles (GAAP).

OPG stated that since January 1, 2012, OPG has sought and received exemptive relief from the Ontario Securities Commission (OSC) and other provincial securities regulators from the requirements of *National Instrument 52-107* (NI 52-107) that allows OPG to file its financial statements using US GAAP instead of International Financial Reporting Standard (IFRS) for continuous disclosure purposes.

OPG stated that the term of the most recent exemption expires on January 1, 2027, subject to certain conditions. In October 2025, OPG filed an application with the OSC requesting the extension of the exemption to the earlier of the effective date of a mandatory IFRS standard for rate-regulated entities (expected to be January 1, 2029) and January 1, 2032.

The application says that the IFRS standard for rate-regulated entities is expected to be finalized in the second quarter of 2026. <https://www.ifrs.org/projects/work-plan/rate-regulated-activities/>

Question(s):

- a) Please provide an update on OPG's October 2025 application with the OSC, including whether OPG has received an exemption to January 1, 2032.
- b) Would the OSC exemption also apply to DNNP LP?
- c) Please elaborate on the expected implications of the mandatory IFRS standard for rate-regulated entities for both OPG and DNNP LP. Is it anticipated that OPG and/or DNNP LP may move from US GAAP to IFRS before the end of the proposed five-year payment amount term?

Response

a) In December 2025, the Ontario Securities Commission ("OSC") issued its final decision in connection with OPG's October 2025 application for an exemption from the requirements of section 3.2 of National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards, enabling OPG to continue to file its financial statements using US GAAP instead of International Financial Reporting Standard (IFRS) for continuous disclosure purposes.

The exemption granted will terminate on the earliest of the following:

- (i) January 1, 2032;
- (ii) if OPG ceases to have rate-regulated activities, the first day of OPG's financial year that commences after OPG ceases to have rate-regulated activities; and
- (iii) the first day of OPG's financial year that commences on or following the later of:
 - 1. the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory rate-regulated standard; and
 - 2. four years after the IASB publishes the final version of a mandatory rate-regulated standard.

The above update is as set out in OPG's 2025 Audited Consolidated Financial Statements and Management Discussion and Analysis at Ex. L-A2-Staff-010, Attachment 1, p. 58.

If the IASB publishes the final mandatory rate-regulated standard in 2026 as expected, the above terms would result in the exemption terminating effective January 1, 2031.

b) As DNNP LP is not a reporting issuer registered with the OSC, it is not subject to the regulatory requirements established by the OSC. However, as an entity consolidated in OPG's consolidated financial statements, DNNP LP's financial reporting is expected to be in accordance with the same accounting standards as applied by OPG. For clarity, US GAAP is the current financial reporting framework for DNNP LP.

c) As OPG's evidence at Ex. A2-1-1, p. 2, lines 11-17 states,

OPG is not currently planning for adoption of IFRS for continuous disclosure purposes. As further discussed in Ex. C1-1-2, OPG is planning to register with the U.S. Securities and Exchange Commission ("SEC") as a

1 Foreign Private Issuer to facilitate access to U.S. debt
2 capital markets. As an SEC registered issuer, OPG would
3 retain the ability to meet its continuous disclosure
4 requirements in Canada by continuing to file its financial
5 statements using US GAAP as permitted under the
6 ongoing exemptions in NI 52-107 available for SEC
7 registered issuers.
8

9 As discussed in Ex. L-C1-Staff-034, there has been no change in OPG's
10 expectations in the above respect and, as such, notwithstanding the expected
11 publication of the IFRS rate-regulated standard, the Applicants do not presently
12 anticipate that either OPG or DNNP LP will transition from US GAAP to IFRS for
13 continuous disclosure purposes before the end of the 2027-2031 IR term.
14

15 For clarity, as discussed in Ex. A2-1-1, Section 2.0, OPG is required to prepare its
16 consolidated financial statements in accordance with US GAAP by Ontario
17 Regulation 395/11 ("O. Reg. 395/11") under the *Financial Administration Act*
18 (Ontario). While these requirements take precedence over the *Securities Act*
19 (Ontario) (and other Ontario legislation), they do not take precedence over the
20 equivalent continuous disclosure requirements of other provincial securities
21 regulators. The requirements of these other securities regulators apply to OPG as
22 it is a reporting issuer in those jurisdictions by virtue of its Medium-Term Notes
23 issued pursuant to a short form base shelf prospectus filed in these jurisdictions
24 and subject to the requirements of *National Instrument 44-101 – Short Form*
25 *Prospectus Distributions*. Accordingly, should OPG ultimately be required to file its
26 consolidated financial statements using IFRS to meet the continuous disclosure
27 requirements of the other provincial securities regulators, it would continue to be
28 legally required to prepare consolidated financial statements in accordance with US
29 GAAP in Ontario.
30

31 Given that the process for OPG to achieve SEC registration will not be concluded
32 in the course of this proceeding and is expected to continue into the IR term, at Ex.
33 H1-1-1, Sections 5.27 and 8.5, the Applicants have proposed to continue the
34 Impacts for IFRS Deferral Account (OPG) for OPG and to establish an equivalent
35 Impacts for IFRS Deferral Account (DNNP) for DNNP LP, and to reassess the
36 matter in the next payment amounts proceeding when the SEC registration process
37 is expected to have been concluded (taking into account as applicable the
38 implications of the O. Reg. 395/11 requirements at the time).

Board Staff Interrogatory #264

Interrogatory

Reference:

Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / pp. 1 & 2

Ref 2: EB-2012-0002, Settlement Agreement, March 14, 2013, pp. 3 & 25 (revised March 22, 2013)

Ref 3: EB-2012-0002, Payment Amounts Order, April 18, 2013, p. 2

Ref 4: EB-2021-0110, Hydro One Networks Inc., Decision and Order on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants, November 29, 2022; Settlement Proposal, October 24, 2022, pp. 54 & 107

Preamble:

OPG stated that as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario) (O. Reg. 395/11), its consolidated financial statements are prepared in accordance with US Generally Accepted Accounting Principles (GAAP).

In 2012, OPG filed an application regarding the adoption of US GAAP for regulatory purposes. In the settlement agreement in that proceeding, the Parties agreed that OPG's adoption of US GAAP for regulatory accounting, reporting and rate-making purposes effective January 1, 2012 was appropriate. The settlement agreement was approved by the OEB.

Hydro One Networks Inc. (Hydro One) filed an application for the period January 1, 2023 to December 31, 2027. A settlement proposal for Hydro One was approved by the OEB on November 29, 2022, including the following terms:

...the Parties agree that subject to the accounting system limitations identified by Hydro One during the proceeding and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will in its next cost-based rate application provide, on a best efforts basis, estimated impacts of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. Hydro One will also, on a best efforts and without prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes...

...to the extent reasonably possible, the impacts will be broken down based on the areas of potential revenue requirement impacts identified in the PwC US

GAAP to IFRS Conversion Impact Review Report (Exhibit A/Tab 6/Schedule 1/Attachment 1/p. 9)...

Question(s):

- a) Please explain whether OPG would see any barriers to performing the tasks agreed to by Hydro One in Hydro One's settlement agreement for 2023-2027 rates and present the results of such tasks in OPG's next payment amounts application (for payment amounts beginning in 2032).

Response

The Applicants do not see material barriers to performing the tasks of the type referenced in the question, should they be required to do so by the OEB. The Applicants note that carrying out the analysis referenced in the question would result in incremental OM&A costs that are not contemplated in their proposed revenue requirements.

The Applicants also observe that, as discussed in Ex. A2-1-1, Section 2.0 and Ex. L-H1-Staff-263, OPG is not currently planning for adoption of IFRS for continuous disclosure purposes in Canada, is required to prepare its consolidated financial statements in accordance with US GAAP by Ontario Regulation 395/11 under the *Financial Administration Act* (Ontario) in Ontario and has received an exemption from the Ontario Securities Commission effectively enabling the company to continue filing its financial statements using US GAAP instead of IFRS for continuous disclosure purposes until January 1, 2031 at the earliest. As discussed in Ex. L-H1-Staff-262, OPG's current filing requirements with the OEB require it to submit payment amounts applications based on US GAAP and, as discussed in Ex. L-C1-Staff-034, once it becomes an SEC registrant, OPG plans to continue using US GAAP for continuous disclosure purposes in Canada and not to seek moving to IFRS for regulatory purposes. In view of the above, the Applicants would disagree with the utility of a blanket requirement for the referenced analysis and believe it would be more practical for the requirement to apply only if OPG were no longer able to use US GAAP for continuous disclosure purposes in Canada.

The Applicants also believe that, if applicable, the referenced analysis should be performed as of the transition date that amounts are recorded in the Impact for IFRS Deferral Accounts proposed in this Application (which for example could be January 1, 2031), rather than as of a fixed date such as the beginning of the next IR term. This would allow the analysis to be reflective of the actual financial impacts of moving to IFRS, should this occur, and to support any balances recorded in such accounts, rather

1 than being a separate hypothetical calculation as of a date that may not be meaningful
2 in those circumstances.
3
4 Finally, to facilitate efficiencies in evidence preparation and regulatory review, the
5 Applicants are of the view that the referenced analysis should be limited to areas with
6 material financial impact and/or revenue requirement impact (see Ex. L-H1-Staff-261).

VECC Interrogatory #015

Interrogatory

Reference:

Exhibits A1-3-2, pg. 35 / H1-1-1, pg.50

Preamble:

“The Earnings Sharing Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record 50% of any regulated earnings for OPG’s combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative 5-year period from January 1, 2022 to December 31, 2026. No entries will be recorded in this account until following the completion of the above five-year period, if applicable.”

Question(s):

- a) Does OPG propose to dispose of any amounts related to earning sharing in this application?
- b) Please provide the annual 2022 to 2025 recordings in the earning sharing deferral account that will be considered with 2026 results to determine the post 2026 disposition.

Response

a) and b)

Any amounts related to earnings sharing for OPG are recorded in the Earnings Sharing Deferral Account, as described in Ex. H1-1-1, Section 5.26. As discussed in that evidence, pursuant to the EB-2020-0290 Payment Amounts Order, the account operates to assess 50% of regulated earnings for OPG’s combined prescribed facilities that exceed 100 basis points above the OEB-approved ROE, if any, on a cumulative 5-year basis for January 1, 2022 to December 31, 2026. Therefore, no entries are recorded in the account until the completion of this current IR term and there are no amounts to consider for disposal in this proceeding.

Refer to Ex. L-H1-SEC-212 for a discussion of the amount projected to be recorded in the Earnings Sharing Deferral Account in respect of the above period.