ONTARIO POWER GENERATION

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BY RESS

November 29, 2021

Ms. Christine Long
Registrar
Ontario Energy Board
27th Floor - 2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Long:

Re: EB-2020-0290 Ontario Power Generation Inc.
Draft Order for Payment Amounts

Attached are a draft payment amounts order and supporting schedules for payment amounts for Ontario Power Generation's prescribed facilities.

The draft payment amounts order reflects the Ontario Energy Board's November 15, 2021 Decision and Order in the EB-2020-0290 proceeding.

If you have any questions regarding this submission, please contact me at evelyn.wong@opg.com.

Respectfully submitted,

Evelyn Wong

cc: Aimee Collier, OPG
Crawford Smith, Lax O'Sullivan Lisus Gottlieb LLP
Charles Keizer, Torys LLP
Intervenors of Record

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2022.

BEFORE: Allison Duff
Presiding Member and Commissioner

Michael Janigan
Commissioner

Pankaj Sardana
Commissioner

DRAFT PAYMENT AMOUNTS ORDER

November 29, 2021

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board ("OEB") on December 31, 2020 (the "Application"). The Application was filed under section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act") seeking approval of the following payment amounts and payment riders:

- a payment amount for hydroelectric generating facilities ("regulated hydroelectric facilities") prescribed under *Ontario Regulation 53/05* of the Act, as amended, ("O. Reg. 53/05"), for the period from January 1, 2022 through December 31, 2026;
- a payment rider for the regulated hydroelectric facilities for the period from January 1, 2022 through December 31, 2026;

- payment amounts for nuclear generating facilities ("nuclear facilities") prescribed under O. Reg. 53/05, for the period from January 1, 2022 through December 31, 2026 ("IR Term"); and
- a payment rider for the nuclear facilities for the period from January 1, 2022 through December 31, 2026.

A full listing of approvals sought by OPG was filed as Ex. A1-2-2.

The OEB issued and published a Notice of Hearing on January 14, 2021 and Procedural Order No. 1 on February 17, 2021. Pursuant to Procedural Order No. 1, the Interrogatories process took place between March and April, 2021. Between May 3-10, 2021, the parties engaged in a four-day Technical Conference, where OPG put forth three witness panels. On May 13, 2021, following the Interrogatories and the Technical Conference, OEB staff filed a letter with the OEB indicating that the parties had reached agreement on a partial proposed issues list for the proceeding. Following an issues list hearing on May 18, 2021, the OEB issued its Decision on Issues List on May 20, 2021, which was amended on May 27, 2021 through the OEB's Decision on Motions. The final approved issues list is attached as Schedule A to the Decision on Motions (the "Issues List").

On June 7, 2021, a settlement conference was held and a comprehensive settlement was achieved by intervenors and OPG with respect to all issues on the Issues List with the exception of the following:

- the in-service additions related to OPG's Heavy Water Storage and Drum Handling Facility ("D2O Storage Project") and associated deferral and variance account balances;
- matters related to small modular reactors ("SMRs") (specifically, the recording of SMR related costs in the Nuclear Development Variance Account in the context of the issue identified by the OEB in its Decision on Issues List, dated May 20, 2021[1], consideration of SMRs as a component of OPG's customer engagement process and SMR-related reporting and record keeping requirements); and
- the appropriate payment amount smoothing

[1] The OEB defined the issue in this proceeding with respect to SMRs as: "The OEB will consider the narrow issue of whether OPG's SMR-related costs are consistent with the purpose of the NDVA [Nuclear Development Variance Account] and thereby appropriate to be booked in the account", Decision on Issues List, p. 9.

(collectively, the “Outstanding Issues”). The Settlement Proposal was filed with the OEB on July 16, 2021 as Exhibit O.

In conjunction with the Settlement Proposal, OPG filed a draft payment amounts order (“Settlement Draft Order”) on July 16, 2021 based on the Settlement Proposal and OPG’s proposed in-service additions for the D2O Storage Project. The Settlement Draft Order included a revised Revenue Requirement Work Form (Appendix H to the Settlement Draft Order). OPG also filed a revised payment amount smoothing proposal to reflect the impact of the Settlement Proposal on revenue requirement, production, and payment amount riders. With the exception of the impacts of the Outstanding Issues, the Settlement Draft Order had been reviewed and agreed to by the parties to the Settlement Proposal.

An oral hearing on the Outstanding Issues other than rate smoothing was held between August 4, 2021 and August 6, 2021. On August 6, 2021, the OEB issued an oral decision approving the Settlement Proposal.

The OEB issued a Decision and Order on the Outstanding Issues other than payment amount smoothing on November 15, 2021 (the “Decision”). A copy of the OEB-approved settlement proposal was attached as Schedule A of the Decision. In the Decision, the OEB directed OPG to file a draft payment amounts order (“Draft Order”) that “reflects the OEB’s findings in the Decision, the 2022 ROE rate as specified by the OEB in its cost of capital report, and OPG’s rate smoothing proposal (including alternatives to its proposal)” (Decision, p. 55). The OEB also directed OPG to “provide a detailed calculation of the impact of the OEB’s findings regarding the D2O [Storage] Project permanent rate base disallowance comprised of $94 million and the carrying costs incurred from May 2017 to March 2020, and the approved change to a March 2020 in-service date, on both the [Capacity Refurbishment Variance Account] balance and rate base in its draft payment amounts order” (Decision, p. 52).

With respect to payment amount smoothing, the Decision directed OPG to include the following alternatives, at minimum, in the Draft Order:

- OPG’s preferred rate smoothing option;
- An illustrative example of an alternative that recovers the entire proposed nuclear revenue requirement for the 2022-2026 period absent any rate smoothing for analysis and comparison purposes only;

- An alternative that recovers less revenue requirement in 2022 compared to OPG's preferred option;
- An alternative that recovers more revenue requirement in 2022 compared to OPG's preferred option; and
- A ranking of the "best" credit metrics alternative, from OPG's perspective.

OPG filed a Draft Order on November 29, 2021, including a revised Revenue Requirement Work Form (filed as Appendix G). The Draft Order included OPG's payment amount smoothing proposal and alternative smoothing scenarios reflecting the Settlement Proposal and the impacts resulting from the Decision, which was filed as Appendix H. OPG proposed to defer recovery of $177.3M of nuclear revenue requirement over the IR Term, which OPG estimated would produce an average year-over-year impact on monthly residential customer bills of $0.19 (or 0.17%) during the IR Term. The Draft Order also included a detailed calculation of the impact of the OEB's findings regarding the D2O Storage Project on both the Capacity Refurbishment Variance Account balance (filed as Appendix D, Table 2) and rate base (filed as Appendix A, Table 9a, Note 3 and Table 10a, Note 4).

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Nuclear Revenue Requirement: The IR term nuclear revenue requirements, net of stretch factor adjustments, are $3,515.5M in 2022, $3,430.0M in 2023, $3,518.3M in 2024, $3,197.6M in 2025, and $2,439.5M in 2026. These amounts are set out in Appendix A, Tables 1 to 5, col. (c), line 26.

2. Nuclear Production Forecast ("NPF"): The production forecast for the nuclear facilities is 33.6 TWh in 2022, 31.2 TWh in 2023, 34.0 TWh in 2024, 31.1 TWh in 2025 and 21.9 TWh in 2026, as set out in Appendix B, Table 1, line 2.

3. Hydroelectric Payment Amounts ("HPA"): As required under s. 6(2)(13)(i) of O. Reg. 53/05*,* commencing on the effective date of January 1, 2022, the payment amount for the regulated hydroelectric facilities is $43.88/MWh, being the amount previously established effective January 1, 2021 in EB-2020-0210. The HPA will apply to the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given month (the "average hourly volume") for each hour of that month. Where the actual net energy

production in MWh from the regulated hydroelectric facilities that is supplied into the IESO-administered energy market in a given hour is greater or less than the average hourly volume, OPG's revenues will be adjusted under the hydroelectric incentive mechanism previously approved by the OEB's Payment Amounts Order in EB-2013-0321. The HPA will continue to apply to 50% of the output of OPG's Chats Falls Generating Station.

4. Nuclear Payment Amounts ("NPA"): Effective January 1 of each year, the NPA over the IR Term is as follows: $102.64/MWh in 2022, $106.30/MWh in 2023, $103.48/MWh in 2024, $102.85/MWh in 2025, and $111.33/MWh in 2026, as set out in Appendix B, Table 1, line 3. These payment amounts reflect the payment amount smoothing proposal in Appendix H and the resulting nuclear rate smoothing deferral amounts approved below.

5. Nuclear Rate Smoothing Deferral Amounts: The nuclear deferral amounts to be recorded in the Rate Smoothing Deferral Account are $66.7M in 2022 and $110.5M in 2023, for a total of $177.3M of deferred revenue. There will be no additions to the RSDA for 2024, 2025 and 2026. The annual deferral amounts are set out in Appendix B, Table 1, line 5.

6. Recovery of Balances in Deferral and Variance Accounts: OPG shall recover the December 31, 2019 audited balances in the following deferral and variance accounts in accordance with Appendix C and Appendix D, effective January 1, 2022:

    - Hydroelectric Water Conditions Variance Account;
    - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
    - Hydroelectric Incentive Mechanism Variance Account;
    - Hydroelectric Surplus Baseload Generation Variance Account[2];
    - Income and Other Taxes Variance Account;
    - Capacity Refurbishment Variance Account[3];
    - Niagara Tunnel Project pre-December 2008 Disallowance Variance Account;

[2] Clearance of a portion equal to $40.0M of the total debit balance in the Hydroelectric Surplus Baseload Generation Variance Account is deferred until the proceeding addressing any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the Independent Electricity System Operator's Market Renewal Program, in accordance with the Settlement Proposal.

[3] OPG shall clear portions of the Capacity Refurbishment Variance Account for the following balances: (1) Non-Darlington Refurbishment Program ("DRP") nuclear variances; (2) Accelerated Investment Incentive Capital Cost Allowance variances for DRP; and (3) the D2O Storage Project. Clearance of the portion of the account balance for all other DRP variances, and for the regulated hydroelectric facilities is deferred to a future application.

- Pension and OPEB Cost Variance Account;
- Pension & OPEB Cash Payment Variance Account;
- Pension & OPEB Cash Versus Accrual Differential Deferral Account;
- Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account;
- Nuclear Liability Deferral Account;
- Nuclear Development Variance Account[4];
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts[5];
- SR&ED ITC Variance Account;
- Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account;
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account; and
- Nuclear Deferral and Variance Over/Under Recovery Variance Account.

7. Continuing Deferral and Variance Accounts: OPG shall continue the following deferral and variance accounts in accordance with Appendix E, effective January 1, 2022:
   - Hydroelectric Water Conditions Variance Account;
   - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
   - Hydroelectric Incentive Mechanism Variance Account;
   - Hydroelectric Surplus Baseload Generation Variance Account;
   - Income and Other Taxes Variance Account;
   - Capacity Refurbishment Variance Account;
   - Pension and OPEB Cost Variance Account;
   - Pension & OPEB Cash Versus Accrual Differential Deferral Account;
   - Pension & OPEB Cash Payment Variance Account;
   - Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account;
   - Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account;

[4] Clearance of the portion of the Nuclear Development Variance Account related to small modular reactors is deferred to a future application.
[5] As set out in Appendix E, OPG shall terminate the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account effective January 1, 2022 by transferring the remaining balance and associated amortization to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

- Gross Revenue Charge Variance Account;
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account;
- Nuclear Liability Deferral Account;
- Nuclear Development Variance Account;
- Bruce Lease Net Revenues Variance Account;
- Nuclear Deferral and Variance Over/Under Recovery Variance Account;
- Impact Resulting from Changes in Station End-of-life Dates (December 31, 2017) Deferral Account;
- SR&ED ITC Variance Account;
- Fitness for Duty Deferral Account; and
- Rate Smoothing Deferral Account

OPG shall also maintain the Pickering Closure Cost Deferral Account established pursuant to s. 5.6(1) of O. Reg. 53/05.

8. New and Terminated Deferral and Variance Accounts: OPG shall establish the following deferral and variance accounts in accordance with Appendix F, effective January 1, 2022, unless otherwise noted:
   - Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, effective January 1, 2021[6];
   - Impact for IFRS Deferral Account;
   - Clarington Corporate Campus Deferral Account;
   - Sale of Unprescribed Kipling Site Deferral Account; and
   - Earnings Sharing Deferral Account.

   OPG shall terminate the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account, effective January 1, 2022, and the Impacts Arising from the COVID-19 Emergency Deferral Account, effective on the date of the OEB's approval of the Settlement Proposal.

9. Hydroelectric Payment Rider ("HPR"): Effective January 1, 2022 to December 31, 2024, the HPR for the recovery of the approved deferral and variance account balances for the

[6] Pursuant to the OEB's Interim Order dated January 20, 2021, this account was established on an interim basis effective January 1, 2021, pending the OEB's final determination in this proceeding.

regulated hydroelectric facilities, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and other adjustments, is $1.03/MWh (Appendix C, Table 1, line 23, cols. (h) to (j)). Effective January 1, 2025 to December 31, 2026, the HPR for the recovery of the approved deferral and variance account balances for the regulated hydroelectric facilities is $0.69/MWh (Appendix C, Table 1, line 23, cols. (k) to (l)). The approved disposition amount for this proceeding is a debit of $101.3M (Appendix C, Table 1, col. (m), line 16) related to hydroelectric deferral and variance accounts, reflecting recovery of audited December 31, 2019 balances in deferral and variance accounts less amortization amounts approved in EB-2016-0152 and EB-2018-0243 for 2020 and 2021 and less amounts deferred to future applications. The HPR will apply to 50% of the output of OPG's Chats Falls Generating Station.

10. <u>Nuclear Payment Rider ("NPR")</u>: The NPR for the recovery of the approved deferral and variance account balances for the nuclear facilities, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and other adjustments, shall be $1.16/MWh for January 1, 2022 to December 31, 2022, $1.25/MWh for January 1, 2023 to December 31, 2023, $1.15/MWh for January 1, 2024 to December 31, 2024, $5.34/MWh for January 1, 2025 to December 31, 2025, and $7.58/MWh for January 1, 2026 to December 31, 2026 (Appendix D, Table 1, line 32). The approved disposition amount for this proceeding is a debit of $281.8M (Appendix D, Table 1, col. (m), line 25) related to nuclear deferral and variance accounts, reflecting recovery of audited December 31, 2019 balances in deferral and variance accounts, less amortization amounts approved in EB-2016-0152 and EB-2018-0243 for 2020 and 2021 and less amounts deferred to future applications, as adjusted for the impact of the OEB's findings regarding the D2O Storage Project.

11. The IESO shall make payments to OPG in accordance with this order as of January 1, 2022.

12. OPG shall file an accounting order application with the OEB and provide notice to intervenors of record in EB-2020-0290 if:
    i. OPG proposes an accounting change impacting the calculation of its nuclear liabilities, other than as a result of an Ontario Nuclear Funds Agreement Reference

Plan update, which results in a material revenue requirement impact for the prescribed facilities; or

ii. OPG proposes to change the end-of-life dates of its prescribed nuclear facilities for depreciation and amortization purposes that results in a material non-asset retirement cost revenue requirement impact.

An accounting order application shall only be required if the revenue requirement impact is neither reflected in current or proposed payment amounts nor recorded in an authorized deferral or variance account and the annualized revenue requirement impact for the prescribed facilities is $10M or greater.

DATED at Toronto _________________, 2021

ONTARIO ENERGY BOARD

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Christine Long
Registrar

EB-2020-0290 PAYMENT AMOUNTS ORDER – APPENDICES

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Table 1

2022 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	8,030.7	(118.7)	7,912.0
2	**Working Capital**		726.0	0.0	726.0
3	**Cash Working Capital**		(37.8)	0.0	(37.8)
4	**Total Rate Base**		8,719.0	(118.7)	8,600.3
	Capitalization				
5	**Short-term Debt**	3	51.1	(0.3)	50.8
6	**Long-Term Debt**	3	4,271.6	367.3	4,638.9
7	**Common Equity at ROE Rate**	3	4,322.7	(614.5)	3,708.2
7a	**Common Equity at Long-Term Debt Rate**	3, 4	0.0	128.8	128.8
8	**Adjustment for Lesser of UNL or ARC**		73.6	0.0	73.6
9	**Total Capital**		8,719.0	(118.7)	8,600.3
	Cost of Capital				
10	**Short-term Debt**	3	2.9	(0.0)	2.9
11	**Long-Term Debt**	3	154.0	13.2	167.2
12	**Return on Equity at ROE Rate**	3	360.5	(39.4)	321.1
12a	**Return on Equity at Long-Term Debt Rate**	3, 4	0.0	4.6	4.6
13	**Adjustment for Lesser of UNL or ARC**		3.6	0.0	3.6
14	**Total Cost of Capital**		521.0	(21.5)	499.5
	Expenses:				
15	**OM&A**	5	2,340.7	(64.5)	2,276.2
16	**Fuel**	6	178.3	(1.0)	177.3
17	**Depreciation & Amortization**	2	551.5	(4.3)	547.2
18	**Property Tax**		12.9	0.0	12.9
19	**Total Expenses**		3,083.4	(69.9)	3,013.5
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**		(45.6)	0.0	(45.6)
21	**Ancillary and Other Revenue**	7	24.2	2.4	26.6
22	**Total Other Revenues**		(21.4)	2.4	(19.0)
23	**Income Tax**	8	(16.5)	0.0	(16.5)
24	**Revenue Requirement Before Stretch Factor**		3,609.3	(93.8)	3,515.5
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	0.0	0.0	0.0
26	**Revenue Requirement Net of Stretch Factor**		3,609.3	(93.8)	3,515.5
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(38.5)	39.1
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,686.9	(132.3)	3,554.6

For notes see Table 1a.

Table 1a
Notes to Table 1
2022 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (a).
2 Adjusted to reflect the OEB approved settlement proposal reduction (Decision and Order, Schedule A, P. 21) of 13% per year to forecasted capital in-service additions for Nuclear Operations and 5% per year to forecasted capital in-service additions for Corporate Support Services. Adjusted also to reflect the rate base impacts resulting from the OEB Decision and Order, PP.33,52 on D2O Storage Project.

Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.
3 Adjusted to reflect the capital structure per the OEB approved settlement proposal of 45% Equity : 55% Debt (Decision and Order, Schedule A, P. 24) and OEB approved 2022 ROE rate. See PAO App. A, Table 11 for supporting details.
4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). See PAO App. A, Table 11 for supporting details.
5 Adjusted to reflect the OEB approved settlement proposal for removal of asset service fees relating to the Clarington Corporate Campus, adjustment to asset service fees for revised capital structure, and a 3% reduction to Nuclear Operations OM&A, Allocation of Corporate Costs OM&A, and Asset Service Fees (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2022
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,340.7
(b)	Removal of Clarington Coprorate Campus asset service fees (Ex. F3-2-1, Table 2, line 4)	$ -
(c)	Adjustment to Reflect Revised Capital Structure within Asset Service Fees (see JT2.31 less Clarington Corporate Campus amounts)	$ (0.6)
(d)	Nuclear Operations OM&A from Ex. F2-1-1 Table 1, line 4	$ 1,690.9
(e)	3% reduction to Nuclear Operations OM&A (d)	$ (50.7)
(f)	Allocation of Corporate Costs, per Ex. F2-1-1 Table 1, line 7, plus PAO App. A, Table 6a, Note 3, lines (b) and (d).	$ 387.6
(g)	3% reduction to Corporate Costs (f)	$ (11.6)
(h)	Asset Service Fees (PAO App. A. Table 7a. Note 9, lines (h) and (m)	$ 50.7
(i)	3% reduction to Asset Service Fees (h)	$ (1.5)
(j)	Settlement Adjusted OM&A Expenses (a) + (b) + (c) + (e) +(g) + (i)	$ 2,276.2

6 Adjusted to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2022
(a)	OPG Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	3.83
(b)	Settlement Adjusted Fuel Bundle Unit Cost ($/MWh) (Decision and Order, Schedule A, P. 26)	3.76
(c)	OPG Proposed Forecast Production (TWh) (Ex. E2-1-1 Table 1, line 3)	33.2
(d)	Settlement Adjusted Forecast Production (TWh) (Decision and Order, Schedule A, P. 25)	33.6
(e)	OPG Proposed Fuel Bundle Cost ($ million) (a) * (c)	127.3
(f)	Settlement Adjusted Fuel Bundle Cost ($ million) (b) * (d)	126.2
(g)	Total Fuel Bundle Cost Adjustment ($ million) (f) - (e)	(1.0)

7 Adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 27).

8 Adjusted to reflect the impacts of the OEB approved settlement proposal as outlined above per PAO App. A, Table 17.
9 Per the OEB approved settlement proposal, adjusted to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Decision and Order, Schedule A, P. 18), expand the scope of the stretch factor to include asset service fees (Decision and Order, Schedule A, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding Darlington Refurbishment Program (Decision and Order, Schedule A, P. 18). Supporting calculation is provided in PAO App. A, Table 7.
10 Adjusted to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 19) and the Capacity Refurbishment Variance Account impacts resulting from the OEB Decision and Order, PP. 35,52 on D2O Storage Project. See PAO App. D, Table 1, line 29.

Table 2

2023 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	8,103.2	(173.9)	7,929.4
2	**Working Capital**		723.3	0.0	723.3
3	**Cash Working Capital**		(37.8)	0.0	(37.8)
4	**Total Rate Base**		8,788.8	(173.9)	8,615.0
	Capitalization				
5	**Short-term Debt**	3	50.9	(0.5)	50.4
6	**Long-Term Debt**	3	4,343.6	344.3	4,687.8
7	**Common Equity at ROE Rate**	3	4,394.4	(630.7)	3,763.7
7a	**Common Equity at Long-Term Debt Rate**	3, 4	0.0	113.0	113.0
8	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
9	**Total Capital**		8,788.8	(173.9)	8,615.0
	Cost of Capital				
10	**Short-term Debt**	3	3.0	(0.0)	3.0
11	**Long-Term Debt**	3	151.4	12.0	163.4
12	**Return on Equity at ROE Rate**	3	366.5	(40.6)	325.9
12a	**Return on Equity at Long-Term Debt Rate**	3, 4	0.0	3.9	3.9
13	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
14	**Total Cost of Capital**		520.9	(24.6)	496.3
	Expenses:				
15	**OM&A**	5	2,381.5	(66.5)	2,315.0
16	**Fuel**	6	182.1	(0.9)	181.2
17	**Depreciation & Amortization**	2	470.0	(7.1)	462.9
18	**Property Tax**		13.2	0.0	13.2
19	**Total Expenses**		3,047.0	(74.5)	2,972.5
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	7	(38.7)	0.0	(38.7)
21	**Ancillary and Other Revenue**		41.9	4.2	46.1
22	**Total Other Revenues**		3.2	4.2	7.4
23	**Income Tax**	8	(16.3)	0.0	(16.3)
24	**Revenue Requirement Before Stretch Factor**		3,548.4	(103.4)	3,445.0
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	9.5	5.4	15.0
26	**Revenue Requirement Net of Stretch Factor**		3,538.8	(108.8)	3,430.0
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(38.5)	39.1
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,616.5	(147.3)	3,469.2

For notes see Table 2a.

Table 2a
Notes to Table 2
2023 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (b).

2 Adjusted to reflect the OEB approved settlement proposal reduction (Decision and Order, Schedule A, P. 21) of 13% per year to forecasted capital in-service additions for Nuclear Operations and 5% per year to forecasted capital in-service additions for Corporate Support Services. Adjusted also to reflect the rate base impacts resulting from the OEB Decision and Order, PP.33,52 on D2O Storage Project.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Adjusted to reflect the capital structure per the OEB approved settlement proposal of 45% Equity : 55% Debt (Decision and Order, Schedule A, P. 24) and OEB approved 2022 ROE rate. See PAO App. A, Table 12 for supporting details.

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). See PAO App. A, Table 12 for supporting details.

5 Adjusted to reflect the OEB approved settlement proposal for removal of asset service fees relating to the Clarington Corporate Campus, adjustment to asset service fees for revised capital structure, and a 3% reduction to Nuclear Operations OM&A, Allocation of Corporate Costs OM&A, and Asset Service Fees (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	**2023**
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,381.5
(b)	Removal of Clarington Coprorate Campus asset service fees (Ex. F3-2-1, Table 2, line 4)	$ -
(c)	Adjustment to Reflect Revised Capital Structure within Asset Service Fees (see JT2.31 less Clarington Corporate Campus amounts)	$ (0.7)
(d)	Nuclear Operations OM&A from Ex. F2-1-1 Table 1, line 4	$ 1,759.5
(e)	3% reduction to Nuclear Operations OM&A (d)	$ (52.8)
(f)	Allocation of Corporate Costs, per Ex. F2-1-1 Table 1, line 7, plus PAO App. A, Table 6a, Note 3, lines (b) and (d).	$ 379.7
(g)	3% reduction to Corporate Costs (f)	$ (11.4)
(h)	Asset Service Fees (PAO App. A. Table 7a. Note 9, lines (h) and (m)	$ 54.3
(i)	3% reduction to Asset Service Fees (h)	$ (1.6)
(j)	Settlement Adjusted OM&A Expenses (a) + (b) + (c) + (e) +(g) + (i)	$ 2,315.0

6 Adjusted to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	**2023**
(a)	OPG Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	3.96
(b)	Settlement Adjusted Fuel Bundle Unit Cost ($/MWh) (Decision and Order, Schedule A, P. 26)	3.88
(c)	OPG Proposed Forecast Production (TWh) (Ex. E2-1-1 Table 1, line 3)	30.8
(d)	Settlement Adjusted Forecast Production (TWh) (Decision and Order, Schedule A, P. 25)	31.2
(e)	OPG Proposed Fuel Bundle Cost ($ million) (a) * (c)	122.0
(f)	Settlement Adjusted Fuel Bundle Cost ($ million) (b) * (d)	121.1
(g)	Total Fuel Bundle Cost Adjustment ($ million) (f) - (e)	(0.9)

7 Adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 27).

8 Adjusted to reflect the impacts of the OEB approved settlement proposal as outlined above per PAO App. A, Table 18.

9 Per the OEB approved settlement proposal, adjusted to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Decision and Order, Schedule A, P. 18), expand the scope of the stretch factor to include asset service fees (Decision and Order, Schedule A, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding Darlington Refurbishment Program (Decision and Order, Schedule A, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Adjusted to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 19) and the Capacity Refurbishment Variance Account impacts resulting from the OEB Decision and Order, PP. 35,52 on D2O Storage Project. See PAO App. D, Table 1, line 29.

Table 3
2024 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	10,624.7	(229.0)	10,395.7
2	**Working Capital**		675.4	0.0	675.4
3	**Cash Working Capital**		(37.8)	0.0	(37.8)
4	**Total Rate Base**		11,262.4	(229.0)	11,033.4
	Capitalization				
5	**Short-term Debt**	3	56.4	(0.5)	55.9
6	**Long-Term Debt**	3	5,574.8	437.7	6,012.4
7	**Common Equity at ROE Rate**	3	5,631.2	(763.8)	4,867.4
7a	**Common Equity at Long-Term Debt Rate**	3, 4	0.0	97.6	97.6
8	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
9	**Total Capital**		11,262.4	(229.0)	11,033.4
	Cost of Capital				
10	**Short-term Debt**	3	3.6	(0.0)	3.6
11	**Long-Term Debt**	3	201.5	15.8	217.3
12	**Return on Equity at ROE Rate**	3	469.6	(48.1)	421.5
12a	**Return on Equity at Long-Term Debt Rate**	3, 4	0.0	3.5	3.5
13	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
14	**Total Cost of Capital**		674.7	(28.8)	645.9
	Expenses:				
15	**OM&A**	5	2,206.3	(69.3)	2,137.0
16	**Fuel**	6	209.4	0.1	209.5
17	**Depreciation & Amortization**	2	577.2	(9.9)	567.4
18	**Property Tax**		13.6	0.0	13.6
19	**Total Expenses**		3,006.5	(79.1)	2,927.5
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	7	(48.1)	0.0	(48.1)
21	**Ancillary and Other Revenue**		52.3	5.2	57.5
22	**Total Other Revenues**		4.2	5.2	9.4
23	**Income Tax**	8	(16.4)	0.0	(16.4)
24	**Revenue Requirement Before Stretch Factor**		3,660.7	(113.1)	3,547.6
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	18.6	10.6	29.3
26	**Revenue Requirement Net of Stretch Factor**		3,642.0	(123.7)	3,518.3
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(38.5)	39.1
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,719.6	(162.2)	3,557.4

For notes see Table 3a.

Table 3a
Notes to Table 3
2024 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (c).

2 Adjusted to reflect the OEB approved settlement proposal reduction (Decision and Order, Schedule A, P. 21) of 13% per year to forecasted capital in-service additions for Nuclear Operations and 5% per year to forecasted capital in-service additions for Corporate Support Services. Adjusted also to reflect the rate base impacts resulting from the OEB Decision and Order, PP.33,52 on D2O Storage Project.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Adjusted to reflect the capital structure per the OEB approved settlement proposal of 45% Equity : 55% Debt (Decision and Order, Schedule A, P. 24) and OEB approved 2022 ROE rate. See PAO App. A, Table 13 for supporting details.

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). See PAO App. A, Table 13 for supporting details.

5 Adjusted to reflect the OEB approved settlement proposal for removal of asset service fees relating to the Clarington Corporate Campus, adjustment to asset service fees for revised capital structure, and a 3% reduction to Nuclear Operations OM&A, Allocation of Corporate Costs OM&A, and Asset Service Fees (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2024
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,206.3
(b)	Removal of Clarington Coprorate Campus asset service fees (Ex. F3-2-1, Table 2, line 4)	$ (8.0)
(c)	Adjustment to Reflect Revised Capital Structure within Asset Service Fees (see JT2.31 less Clarington Corporate Campus amounts)	$ (0.6)
(d)	Nuclear Operations OM&A from Ex. F2-1-1 Table 1, line 4	$ 1,591.2
(e)	3% reduction to Nuclear Operations OM&A (d)	$ (47.7)
(f)	Allocation of Corporate Costs, per Ex. F2-1-1 Table 1, line 7, plus PAO App. A, Table 6a, Note 3, lines (b) and (d).	$ 374.7
(g)	3% reduction to Corporate Costs (f)	$ (11.2)
(h)	Asset Service Fees (PAO App. A. Table 7a. Note 9, lines (h) and (m)	$ 56.3
(i)	3% reduction to Asset Service Fees (h)	$ (1.7)
(j)	Settlement Adjusted OM&A Expenses (a) + (b) + (c) + (e) +(g) + (i)	$ 2,137.0

6 Adjusted to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2024
(a)	OPG Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	4.37
(b)	Settlement Adjusted Fuel Bundle Unit Cost ($/MWh) (Decision and Order, Schedule A, P. 26)	4.28
(c)	OPG Proposed Forecast Production (TWh) (Ex. E2-1-1 Table 1, line 3)	33.3
(d)	Settlement Adjusted Forecast Production (TWh) (Decision and Order, Schedule A, P. 25)	34.0
(e)	OPG Proposed Fuel Bundle Cost ($ million) (a) * (c)	145.5
(f)	Settlement Adjusted Fuel Bundle Cost ($ million) (b) * (d)	145.6
(g)	Total Fuel Bundle Cost Adjustment ($ million) (f) - (e)	0.1

7 Adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 27).

8 Adjusted to reflect the impacts of the OEB approved settlement proposal as outlined above per PAO App. A, Table 19.

9 Per the OEB approved settlement proposal, adjusted to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Decision and Order, Schedule A, P. 18), expand the scope of the stretch factor to include asset service fees (Decision and Order, Schedule A, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding Darlington Refurbishment Program (Decision and Order, Schedule A, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Adjusted to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 19) and the Capacity Refurbishment Variance Account impacts resulting from the OEB Decision and Order, PP. 35,52 on D2O Storage Project. See PAO App. D, Table 1, line 29.

Numbers may not add due to rounding.

Table 4
2025 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	11,887.5	(282.7)	11,604.8
2	**Working Capital**		621.8	0.0	621.8
3	**Cash Working Capital**		(37.8)	0.0	(37.8)
4	**Total Rate Base**		12,471.6	(282.7)	12,188.8
	Capitalization				
5	**Short-term Debt**	3	57.9	(0.5)	57.3
6	**Long-Term Debt**	3	6,177.9	468.6	6,646.5
7	**Common Equity at ROE Rate**	3	6,235.8	(834.9)	5,400.9
7a	**Common Equity at Long-Term Debt Rate**	3, 4	0.0	84.1	84.1
8	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
9	**Total Capital**		12,471.6	(282.7)	12,188.8
	Cost of Capital				
10	**Short-term Debt**	3	4.0	(0.0)	3.9
11	**Long-Term Debt**	3	225.7	17.1	242.8
12	**Return on Equity at ROE Rate**	3	520.1	(52.3)	467.7
12a	**Return on Equity at Long-Term Debt Rate**	3, 4	0.0	3.1	3.1
13	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
14	**Total Cost of Capital**		749.7	(32.2)	717.5
	Expenses:				
15	**OM&A**	5	1,871.6	(68.4)	1,803.3
16	**Fuel**	6	188.6	1.3	189.9
17	**Depreciation & Amortization**	2	520.1	(12.3)	507.8
18	**Property Tax**		12.7	0.0	12.7
19	**Total Expenses**		2,593.0	(79.4)	2,513.6
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**		(46.5)	0.0	(46.5)
21	**Ancillary and Other Revenue**	7	21.8	2.2	24.0
22	**Total Other Revenues**		(24.7)	2.2	(22.5)
23	**Income Tax**	8	(16.1)	0.0	(16.1)
24	**Revenue Requirement Before Stretch Factor**		3,351.4	(113.8)	3,237.6
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	25.5	14.4	40.0
26	**Revenue Requirement Net of Stretch Factor**		3,325.8	(128.2)	3,197.6
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**		166.2	0.0	166.2
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,492.0	(128.2)	3,363.7

For notes see Table 4a.

Table 4a
Notes to Table 4
2025 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (d).

2 Adjusted to reflect the OEB approved settlement proposal reduction (Decision and Order, Schedule A, P. 21) of 13% per year to forecasted capital in-service additions for Nuclear Operations and 5% per year to forecasted capital in-service additions for Corporate Support Services. Adjusted also to reflect the rate base impacts resulting from the OEB Decision and Order, PP.33,52 on D2O Storage Project.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Adjusted to reflect the capital structure per the OEB approved settlement proposal of 45% Equity : 55% Debt (Decision and Order, Schedule A, P. 24) and OEB approved 2022 ROE rate. See PAO App. A, Table 14 for supporting details.

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). See PAO App. A, Table 14 for supporting details.

5 Adjusted to reflect the OEB approved settlement proposal for removal of asset service fees relating to the Clarington Corporate Campus, adjustment to asset service fees for revised capital structure, and a 3% reduction to Nuclear Operations OM&A, Allocation of Corporate Costs OM&A, and Asset Service Fees (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2025
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 1,871.6
(b)	Removal of Clarington Coprorate Campus asset service fees (Ex. F3-2-1, Table 2, line 4)	$ (16.0)
(c)	Adjustment to Reflect Revised Capital Structure within Asset Service Fees (see JT2.31 less Clarington Corporate Campus amounts)	$ (0.6)
(d)	Nuclear Operations OM&A from Ex. F2-1-1 Table 1, line 4	$ 1,338.8
(e)	3% reduction to Nuclear Operations OM&A (d)	$ (40.2)
(f)	Allocation of Corporate Costs, per Ex. F2-1-1 Table 1, line 7, plus PAO App. A, Table 6a, Note 3, lines (b) and (d).	$ 337.1
(g)	3% reduction to Corporate Costs (f)	$ (10.1)
(h)	Asset Service Fees (PAO App. A. Table 7a. Note 9, lines (h) and (m)	$ 53.0
(i)	3% reduction to Asset Service Fees (h)	$ (1.6)
(j)	Settlement Adjusted OM&A Expenses (a) + (b) + (c) + (e) +(g) + (i)	$ 1,803.3

6 Adjusted to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2025
(a)	OPG Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	4.61
(b)	Settlement Adjusted Fuel Bundle Unit Cost ($/MWh) (Decision and Order, Schedule A, P. 26)	4.52
(c)	OPG Proposed Forecast Production (TWh) (Ex. E2-1-1 Table 1, line 3)	30.2
(d)	Settlement Adjusted Forecast Production (TWh) (Decision and Order, Schedule A, P. 25)	31.1
(e)	OPG Proposed Fuel Bundle Cost ($ million) (a) * (c)	139.2
(f)	Settlement Adjusted Fuel Bundle Cost ($ million) (b) * (d)	140.4
(g)	Total Fuel Bundle Cost Adjustment ($ million) (f) - (e)	1.3

7 Adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 27).

8 Adjusted to reflect the impacts of the OEB approved settlement proposal as outlined above per PAO App. A, Table 20.

9 Per the OEB approved settlement proposal, adjusted to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Decision and Order, Schedule A, P. 18), expand the scope of the stretch factor to include asset service fees (Decision and Order, Schedule A, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding Darlington Refurbishment Program (Decision and Order, Schedule A, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

Numbers may not add due to rounding.

Table 5
2026 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	12,783.5	(324.8)	12,458.6
2	**Working Capital**		570.9	0.0	570.9
3	**Cash Working Capital**		(37.8)	0.0	(37.8)
4	**Total Rate Base**		13,316.6	(324.8)	12,991.8
	Capitalization				
5	**Short-term Debt**	3	58.4	(0.6)	57.9
6	**Long-Term Debt**	3	6,599.9	487.7	7,087.6
7	**Common Equity at ROE Rate**	3	6,658.3	(885.0)	5,773.4
7a	**Common Equity at Long-Term Debt Rate**	3, 4	0.0	73.0	73.0
8	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
9	**Total Capital**		13,316.6	(324.8)	12,991.8
	Cost of Capital				
10	**Short-term Debt**	3	4.3	(0.0)	4.3
11	**Long-Term Debt**	3	241.2	17.8	259.0
12	**Return on Equity at ROE Rate**	3	555.3	(55.3)	500.0
12a	**Return on Equity at Long-Term Debt Rate**	3, 4	0.0	2.7	2.7
13	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
14	**Total Cost of Capital**		800.8	(34.9)	765.9
	Expenses:				
15	**OM&A**	5	1,086.0	(47.1)	1,038.9
16	**Fuel**	6	148.2	(0.2)	148.0
17	**Depreciation & Amortization**	2	567.1	(14.7)	552.4
18	**Property Tax**		9.8	0.0	9.8
19	**Total Expenses**		1,811.0	(62.0)	1,749.0
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**		(38.3)	0.0	(38.3)
21	**Ancillary and Other Revenue**	7	63.8	6.4	70.2
22	**Total Other Revenues**		25.5	6.4	31.9
23	**Income Tax**	8	(15.9)	0.0	(15.9)
24	**Revenue Requirement Before Stretch Factor**		2,570.4	(103.3)	2,467.2
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	18.0	9.6	27.7
26	**Revenue Requirement Net of Stretch Factor**		2,552.4	(112.9)	2,439.5
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**		166.2	0.0	166.2
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		2,718.6	(112.9)	2,605.6

For notes see Table 5a.

Table 5a
Notes to Table 5
2026 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (e).

2 Adjusted to reflect the OEB approved settlement proposal reduction (Decision and Order, Schedule A, P. 21) of 13% per year to forecasted capital in-service additions for Nuclear Operations and 5% per year to forecasted capital in-service additions for Corporate Support Services. Adjusted also to reflect the rate base impacts resulting from the OEB Decision and Order, PP.33,52 on D2O Storage Project.

Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Adjusted to reflect the capital structure per the OEB approved settlement proposal of 45% Equity : 55% Debt (Decision and Order, Schedule A, P. 24) and OEB approved 2022 ROE rate. See PAO App. A, Table 15 for supporting details.

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). See PAO App. A, Table 15 for supporting details.

5 Adjusted to reflect the OEB approved settlement proposal for removal of asset service fees relating to the Clarington Corporate Campus, adjustment to asset service fees for revised capital structure, and a 3% reduction to Nuclear Operations OM&A, Allocation of Corporate Costs OM&A, and Asset Service Fees (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2026
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 1,086.0
(b)	Removal of Clarington Coprorate Campus asset service fees (Ex. F3-2-1, Table 2, line 4)	$ (15.3)
(c)	Adjustment to Reflect Revised Capital Structure within Asset Service Fees (see JT2.31 less Clarington Corporate Campus amounts)	$ (0.5)
(d)	Nuclear Operations OM&A from Ex. F2-1-1 Table 1, line 4	$ 739.7
(e)	3% reduction to Nuclear Operations OM&A (d)	$ (22.2)
(f)	Allocation of Corporate Costs, per Ex. F2-1-1 Table 1, line 7, plus PAO App. A, Table 6a, Note 3, lines (b) and (d).	$ 255.8
(g)	3% reduction to Corporate Costs (f)	$ (7.7)
(h)	Asset Service Fees (PAO App. A. Table 7a. Note 9, lines (h) and (m)	$ 49.3
(i)	3% reduction to Asset Service Fees (h)	$ (1.5)
(j)	Settlement Adjusted OM&A Expenses (a) + (b) + (c) + (e) +(g) + (i)	$ 1,038.9

6 Adjusted to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 25), calculated as follows:

	Description	2026
(a)	OPG Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	4.82
(b)	Settlement Adjusted Fuel Bundle Unit Cost ($/MWh) (Decision and Order, Schedule A, P. 26)	4.73
(c)	OPG Proposed Forecast Production (TWh) (Ex. E2-1-1 Table 1, line 3)	21.5
(d)	Settlement Adjusted Forecast Production (TWh) (Decision and Order, Schedule A, P. 25)	21.9
(e)	OPG Proposed Fuel Bundle Cost ($ million) (a) * (c)	103.7
(f)	Settlement Adjusted Fuel Bundle Cost ($ million) (b) * (d)	103.5
(g)	Total Fuel Bundle Cost Adjustment ($ million) (f) - (e)	(0.2)

7 Adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 27).

8 Adjusted to reflect the impacts of the OEB approved settlement proposal as outlined above per PAO App. A, Table 21.

9 Per the OEB approved settlement proposal, adjusted to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Decision and Order, Schedule A, P. 18), expand the scope of the stretch factor to include asset service fees (Decision and Order, Schedule A, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding Darlington Refurbishment Program (Decision and Order, Schedule A, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

Table 6

2022 to 2026 Summary of Proposed Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)
			Note 1	Note 1	Note 1	Note 1	Note 1
	Rate Base						
1	**Net Fixed Assets**	2	8,030.7	8,103.2	10,624.7	11,887.5	12,783.5
2	**Working Capital**		726.0	723.3	675.4	621.8	570.9
3	**Cash Working Capital**		(37.8)	(37.8)	(37.8)	(37.8)	(37.8)
4	**Total Rate Base**		8,719.0	8,788.8	11,262.4	12,471.6	13,316.6
	Capitalization						
5	**Short-term Debt**	2	51.1	50.9	56.4	57.9	58.4
6	**Long-Term Debt**	2	4,271.6	4,343.6	5,574.8	6,177.9	6,599.9
7	**Common Equity**	2	4,322.7	4,394.4	5,631.2	6,235.8	6,658.3
8	**Adjustment for Lesser of UNL or ARC**		73.6	0.0	0.0	0.0	0.0
9	**Total Capital**		8,719.0	8,788.8	11,262.4	12,471.6	13,316.6
	Cost of Capital						
10	**Short-term Debt**	2	2.9	3.0	3.6	4.0	4.3
11	**Long-Term Debt**	2	154.0	151.4	201.5	225.7	241.2
12	**Return on Equity at ROE Rate**	2	360.5	366.5	469.6	520.1	555.3
13	**Adjustment for Lesser of UNL or ARC**		3.6	0.0	0.0	0.0	0.0
14	**Total Cost of Capital**		521.0	520.9	674.7	749.7	800.8
	Expenses:						
15	**OM&A**	3	2,340.7	2,381.5	2,206.3	1,871.6	1,086.0
16	**Fuel**		178.3	182.1	209.4	188.6	148.2
17	**Depreciation & Amortization**	4	551.5	470.0	577.2	520.1	567.1
18	**Property Tax**		12.9	13.2	13.6	12.7	9.8
19	**Total Expenses**		3,083.4	3,047.0	3,006.5	2,593.0	1,811.0
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**		(45.6)	(38.7)	(48.1)	(46.5)	(38.3)
21	**Ancillary and Other Revenue**		24.2	41.9	52.3	21.8	63.8
22	**Total Other Revenues**		(21.4)	3.2	4.2	(24.7)	25.5
23	**Income Tax**		(16.5)	(16.3)	(16.4)	(16.1)	(15.9)
24	**Revenue Requirement Before Stretch Factor**		3,609.3	3,548.4	3,660.7	3,351.4	2,570.4
	(line 14 + line 19 - line 22 + line 23)						
25	**Cumulative Nuclear Stretch Dollars**		0.0	9.5	18.6	25.5	18.0
26	**Revenue Requirement Net of Stretch Factor**		3,609.3	3,538.8	3,642.0	3,325.8	2,552.4
	(line 24 - line 25)						
27	**Amortization of Deferral & Variance Account Amounts**		77.6	77.6	77.6	166.2	166.2
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,686.9	3,616.5	3,719.6	3,492.0	2,718.6

For notes see Table 6a.

Table 6a
Notes to Table 6
2022 to 2026 Summary of Proposed Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 1 unless otherwise noted.

2 Revised from Ex. I1-1-1, Table 1 to reflect adjustments identified at Ex. L-B1-01-Staff-024 and Ex. L-F4-01-Staff-269.
Line 1 (2022): PAO, App. A, Table 9, line 9, col. (f), less PAO, App. A, Table 9, line 6, col. (f), less PAO, App. A, Table 9, line 3, col. (f), plus Ex. B3-3-1, Table 2, line 3, col. (f), less App. A, Table 10 line 9, col. (e), plus PAO, App. A, Table 10, line 6, col. (e), plus PAO, App. A, Table 10, line 3, col. (e), less Ex. B3-4-1, Table 2, line 19, col. (f).
Line 1 (2023): PAO, App. A, Table 9, line 18, col. (f), less PAO, App. A, Table 9, line 15, col. (f), less PAO, App. A, Table 9, line 12, col. (f), plus Ex. B3-3-1, Table 2, line 11, col. (f), less App. A, Table 10, line 18, col. (e), plus PAO, App. A, Table 10, line 15, col. (e), plus PAO, App. A, Table 10, line 12, col. (e), less Ex. B3-4-1, Table 2, line 27, col. (f).
Line 1 (2024): PAO, App. A, Table 9, line 27 col. (f), less PAO, App. A, Table 9, line 24, col. (f), less PAO, App. A, Table 9, line 21, col. (f), plus Ex. B3-3-1, Table 2, line 19, col. (f), less App. A, Table 10, line 27, col. (e), plus PAO, App. A, Table 10, line 24, col. (e), plus PAO, App. A, Table 10, line 21, col. (e), less Ex. B3-4-1, Table 2, line 35, col. (f).
Line 1 (2025): PAO, App. A, Table 9, line 36, col. (f), less PAO, App. A, Table 9, line 33, col. (f), less PAO, App. A, Table 9, line 30, col. (f), plus Ex. B3-3-1, Table 2, line 27, col. (f), less App. A, Table 10, line 36, col. (e), plus PAO, App. A, Table 10, line 33, col. (e), plus PAO, App. A, Table 10, line 30, col. (e), less Ex. B3-4-1, Table 3, line 3, col. (f).
Line 1 (2026): PAO, App. A, Table 9, line 45, col. (f), less PAO, App. A, Table 9, line 42, col. (f), less PAO, App. A, Table 9, line 39, col. (f), plus Ex. B3-3-1, Table 2, line 35, col. (f), less App. A, Table 10, line 45, col. (e), plus PAO, App. A, Table 10, line 42, col. (e), plus PAO, App. A, Table 10, line 39, col. (e), less Ex. B3-4-1, Table 3, line 11, col. (f).

3 Revised from Ex. I1-1-1, Table 1 to reflect adjustments identified at Ex. L-D3-1-SEC-110, Ex. L-F3-02-Staff-264, and Ex. JT2.30, as follows:

	Description	**2022**	**2023**	**2024**	**2025**	**2026**
(a)	Per Ex. I1-1-1 Table 1, line 15	2,341.2	2,382.0	2,207.1	1,869.0	1,083.3
(b)	Adjustment per Ex. L-D3-1-SEC-110	-0.9	-0.9	-0.9	-0.9	-0.9
(c)	Adjustment per Ex. L-F3-02-Staff-264	-0.2	-0.2	-0.2	-0.2	-0.2
(d)	Adjustment per Ex. JT2.30	0.6	0.6	0.3	3.7	3.8
(e)	Per. PAO App. A, Table 6, line 15	2,340.7	2,381.5	2,206.3	1,871.6	1,086.0

4 Revised from Ex. I1-1-1, Table 1 to reflect a reduction in the annual depreciation expense of $1.5M identified in Ex. L-F4-01-Staff-269.

Table 7
Calculation of Nuclear Stretch Factor
January 1, 2022 to December 31, 2026 ($M)

Line No.	Description	Note	2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
	Darlington Nuclear OM&A Expenses						
1	Base OM&A	1		576.2	582.8	578.6	616.3
2	Project OM&A	2		74.0	70.6	70.9	62.0
3	Outage OM&A	3		187.2	94.7	192.6	61.3
4	Allocation of Corporate Costs	4		198.8	199.6	201.5	255.8
5	Asset Service Fees	9		25.4	26.8	29.1	49.3
6	Darlington Total OM&A Expenses Subject to Stretch Factor (sum of lines 1 to 5)			1,061.5	974.5	1,072.6	1,044.8
	Pickering Total Nuclear OM&A Expenses						
7	Base OM&A	5		730.1	709.8	490.5	-
8	Project OM&A	6		11.0	10.0	5.8	-
9	Outage OM&A	7		157.4	104.0	-	-
10	Allocation of Corporate Costs	8		180.9	175.1	135.7	-
11	Asset Service Fees	9		28.9	29.5	23.9	-
12	Pickering Total OM&A Expenses Subject to Stretch Factor (sum of lines 7 to 11)			1,108.3	1,028.3	655.9	-
13	3% OM&A Reduction Settlement Adjustment	10		(65.1)	(60.1)	(51.9)	(31.3)
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington and Operations & Project Support Capital Related Revenue Requirement						
14	Cost of Capital	11		136.1	156.6	170.2	183.1
15	Depreciation Expense	11		159.0	178.5	192.9	202.2
16	Income Tax Expense on Cost of Capital and Depreciation Expense	11		82.7	93.4	101.2	107.1
17	Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor (line 14 + line 15 + line 16)			377.7	428.5	464.4	492.5
	Pickering Capital Related Revenue Requirement						
18	Cost of Capital	12		8.7	4.5	2.3	0.0
19	Depreciation Expense	12		78.1	76.5	0.4	0.0
20	Income Tax Expense on Cost of Capital and Depreciation Expense	12		27.9	26.5	0.6	0.0
21	Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor (line 18 + line 19 + line 20)			114.7	107.4	3.3	0.0
22	Income Tax Expense- Capital Cost Allowance	13		(101.9)	(92.1)	(100.1)	(95.9)
23	Total Revenue Requirement Amount Subject to Stretch Factor (line 6 + line 12 + line 13 + line 17 + line 21 + line 22)			2,495.3	2,386.6	2,044.2	1,410.0
24	Nuclear Stretch Factor	14		0.60%	0.60%	0.60%	0.30%
25	**Nuclear Stretch Factor Revenue Requirement Adjustment**	15		**15.0**	**29.3**	**40.0**	**27.7**

Notes:
Refer to Table 7a

Table 7a
Notes to Table 7

Notes:
1 From Ex. F2-2-1, Table 1, line 1, col. (h)-(k) for 2023-2026, plus Ex. F2-2-1, Table 10-13, line 8, col. (a), respectively, for 2023-2026.
2 Ex. F2-3-1, Table 1, line 1, plus Darlington lines of Ex. F2-3-1, Table 1, Note 4.
3 From Ex. F2-4-1, Table 1, line 3.
4 From Ex. F3-1-1, Table 3a, line 11, cols. (h)-(k), as adjusted per PAO App. A, Table 6a, Note 3, lines (b) and (d).
5 From Ex. F2-2-1, Table 1, line 2, cols. (h)-(k) for 2023-2026, plus Ex. F2-2-1, Tables 10-13, line 8, col. (b), respectively, for 2023-2026.
6 Ex. F2-3-1, Table 1, line 2, plus Pickering lines of Ex. F2-3-1, Table 1, Note 4.
7 From Ex. F2-4-1, Table 1, line 6.
8 From Ex. F3-1-1, Table 3b, line 11, cols. (h)-(k), as adjusted per PAO App. A, Table 6a, Note 3, lines (b) and (d).
9 Calculated as follows, including settlement adjustments for removal of asset service fees relating to Clarington Corporate Campus and the impact of revised capital structure (Decision and Order, Schedule A, P. 25):

		2022	2023	2024	2025	2026
(a)	OPG Proposed Asset Service Fees- Darlington	23.7	25.9	32.8	41.4	65.3
(b)	OPG Proposed Asset Service Fees- Pickering	27.8	29.3	32.3	28.3	-
(c)	OPG Proposed Nuclear Asset Service Fees- Ex. F2-1-1 Table 1, cols. (h)-(k), line 9	51.5	55.2	65.1	69.7	65.3
(d)	OPG Proposed Asset Service Fees- Darlington - line (a)	23.7	25.9	32.8	41.4	65.3
(e)	Adjustment per Ex. L-F3-02-Staff-264 (Darlington portion)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)
(f)	Removal of Clarington Coprorate Campus asset service fees	-	-	(5.6)	(11.9)	(15.3)
(g)	Adjustment to reflect OEB approved settlement proposal capital structure within the asset service fees	(0.3)	(0.3)	(0.3)	(0.3)	(0.5)
(h)	Revised Asset Service Fees- Darlington	23.3	25.4	26.8	29.1	49.3
(i)	OPG Proposed Asset Service Fees- Pickering - line (b)	27.8	29.3	32.3	28.3	-
(j)	Adjustment per Ex. L-F3-02-Staff-264 (Pickering portion)	(0.1)	(0.1)	(0.1)	(0.1)	-
(k)	Removal of Clarington Coprorate Campus asset service fees	-	-	(2.4)	(4.1)	-
(l)	Adjustment to reflect OEB approved settlement proposal capital structure within the asset service fees	(0.3)	(0.4)	(0.3)	(0.2)	-
(m)	Revised Asset Service Fees- Pickering	27.4	28.9	29.5	23.9	-

10 Calculated as -3% of lines 6 and 12 (Ex.O-1-1, P. 25).
11 Settlement adjusted cost of capital component of Darlington and Operations & Project Support Capital Related Revenue Requirement for 2023-2026 is calculated as follows:

		2023	2024	2025	2026
(a)	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2023: PAO App. A, Table 9, col. (f), lines 10, 14-15 less PAO App. A, Table 10, col. (e), lines 10, 14-15 less Line (b) below; 2024: PAO App. A, Table 9, col. (f), lines 19, 23-24 less PAO App. A Table 10, col. (e), lines 19, 23-24 less Line (b) below; 2025: PAO App. A, Table 9, col. (f), lines 28, 32-33 less PAO App. A, Table 10, col. (e), lines 28, 32-33 less Line (b) below; 2026: PAO App. A, Table 9, col. (f), lines 37, 41-42 less App. A Table 10, col. (e), lines 37, 41-42 less Line (b) below.	2,189.0	2,523.3	2,759.1	2,991.1
(b)	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which common equity is subject to return at long-term debt rate (PAO App. A, Table 16, col. (e), lines 33 and 37 less PAO App. A, Table 16c, col. (e), lines 9, 13, 17, 21, 25, 29, 33 and 37)	242.0	213.8	186.8	162.1
(c)	Return on Equity at ROE Rate (line (a) x 45% x 8.66%)	85.3	98.3	107.5	116.6
(d)	Return on Equity at Long-Term Debt Rate (line (b) x 45% x PAO App. A., Tables 12-15, col. (c), line 5)	3.8	3.5	3.1	2.7
(e)	Cost of Debt ((line (a) + line (b)) x 55% x PAO App. A, Tables 12-15, col. (c), line 4)	47.0	54.8	59.6	63.9
(f)	Total Cost of Capital (lines (c) + (d) + (e))	**136.1**	**156.6**	**170.2**	**183.1**
(g)	Depreciation Expense 2023: PAO App. A, Table 10, col. (b), lines 10, 14-15; 2024: PAO App. A Table 10, col. (b), lines 19, 23-24; 2025: PAO App. A, Table 10, col. (b), lines 28, 32-33; 2026: PAO App. A Table 10, col. (b), lines 37, 41-42	**159.0**	**178.5**	**192.9**	**202.2**
(h)	Net Regulatory Taxable Income Increase / (Decrease) (line (c) + line (d) + line (g))	248.1	280.3	303.5	321.4
(i)	Income Tax Expense (line (h) x 25% / (1 - 25%))	**82.7**	**93.4**	**101.2**	**107.1**

12 Settlement adjusted cost of capital component of Pickering Capital Related Revenue Requirement for 2023-2026 is calculated as follows:

		2023	2024	2025	2026
(a)	Pickering GS Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2023: PAO App. A, Table 9, col. (f), line 13 less PAO App. A, Table 10, col. (e), line 13 less Line (b) below; 2024: PAO App. A, Table 9, col. (f), line 22 less PAO App. A Table 10, col. (e), line 22 less Line (b) below; 2025: PAO App. A, Table 9, col. (f), line 31 less PAO App. A, Table 10, col. (e), line 31 less Line (b) below; 2026: PAO App. A, Table 9, col. (f), line 40 less PAO App. A Table 10, col. (e), line 40 less Line (b) below.	143.8	73.7	38.7	-
(b)	Pickering GS Net Fixed Asset Rate Base for which Common Equity is Subject to Return at Long-Term Debt Rate (PAO App. A, Table 16, col. (e), line 36 less PAO App. A, Table 16c, col. (e), lines 12, 20, 28, 36)	9.1	3.0	-	-
(c)	Return on Equity at ROE Rate (line (a) x 45% x 8.66%)	5.6	2.9	1.5	-
(d)	Return on Equity at Long-Term Debt Rate (line (b) x 45% x PAO App. A., Tables 12-15, col. (c), line 5)	0.1	0.0	-	-
(e)	Cost of Debt ((line (a) + line (b)) x 55% x PAO App. A, Tables 12-15, col. (c), line 4)	3.0	1.5	0.8	-
(f)	Total Cost of Capital (lines (c) + (d) + (e))	**8.7**	**4.5**	**2.3**	**-**
(g)	Depreciation Expense PAO App. A, Table 10, col. (b), lines 13, 22, 31 and 40	**78.1**	**76.5**	**0.4**	**-**
(h)	Net Regulatory Taxable Income Increase / (Decrease) (line (c) + line (d) + line (g))	83.8	79.4	1.9	-
(i)	Income Tax Expense (line (h) x 25% / (1 - 25%))	**27.9**	**26.5**	**0.6**	**-**

13 Settlement adjusted income tax component of CCA-related revenue requirement for 2023-2026 is calculated as follows:

		2023	2024	2025	2026
(a)	Capital Cost Allowance & Other Deductions (PAO App. A, Tables 18-21, col. (c), line 14 less Darlington Refurbishment Program CCA per Ex. F4-2-1 Table 3c, note 3 plus adjustment for the impact of the OEB Decision and Order on D2O Storage Project) plus other deductions	(305.7)	(276.3)	(300.2)	(287.7)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))	**(101.9)**	**(92.1)**	**(100.1)**	**(95.9)**

14 Per OEB approved settlement proposal (Decision and Order, Schedule A, P. 19.)
15 The nuclear stretch factor revenue requirement adjustment can be further broken down as follows:

		2023	2024	2025	2026
(a)	Darlington OM&A Stretch Factor Adjustment (line 6 x line 24) + Prior Year	6.4	12.2	18.7	21.8
(b)	Pickering OM&A Stretch Factor Adjustment (line 12 x line 24) + Prior Year +	6.7	12.8	15.2	
(c)	3% OM&A Reduction Settlement Adjustment Stretch Factor Impact (line 13 x line 24) + Prior Year	(0.4)	(0.8)	(1.1)	(1.2)
(d)	OM&A Stretch Factor Adjustment (a) + (b) + (c)	12.6	24.3	32.8	20.6
(e)	Darlington GS and Operations & Project Support Capital Stretch Factor Adj. Before CCA (line 17 x line 24) + Prior Year	2.3	4.8	7.6	9.1
(f)	Pickering GS Capital Stretch Factor Adjustment Before CCA (line 21 x line 24) + Prior Year ++	0.7	1.3	1.4	-
(g)	Income Tax Expense- Capital Cost Allowance (line 22 x line 24) + Prior Year	(0.6)	(1.2)	(1.8)	(2.1)
(h)	Total Nuclear Stretch Factor Revenue Requirement Adjustment (sum of lines (d) to (g))	15.0	29.3	40.0	27.7

+ 2025 adjusted for removal of Pickering Units 1 & 4. 2026 adjusted for removal of Pickering Units 5-8.
++ 2026 adjusted for removal of Pickering Units.

Table 8
Summary of Revenue Deficiency - Nuclear
January 1, 2022 to December 31, 2026

Line No.	Description	Note	Nuclear 2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	33.6	31.2	34.0	31.1	21.9
2	**2021 Payment Amount per EB-2016-0152 ($/MWh)**	2	89.70	89.70	89.70	89.70	89.70
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		3,013.9	2,801.1	3,049.8	2,788.7	1,965.4
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		501.5	628.9	468.5	408.9	474.0

Notes:
1 Production forecast per OEB approved settlement proposal (Decision and Order, Schedule A, P. 25)
2 EB-2016-0152 Payment Amounts Order, App. C, Table 1, line 3, col. (e).
3 PAO App. A, Tables 1-5, line 26, col. (c).

Table 9
Continuity of Property, Plant and Equipment - Nuclear ($M)
Years Ending December 31, 2022 to 2026

Line No.	Prescribed Facility	Note	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)
		1						
	2022:							
1	**Darlington NGS**		2,517.0	457.6	0.0	457.6	2,974.7	2,692.2
2	**Darlington Refurbishment Program - Excluding D2O**		5,592.2	0.0	(134.6)	(134.6)	5,457.6	5,457.6
3	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	3	395.6	0.0	0.0	0.0	395.6	395.6
4	**Pickering NGS**		2,657.5	12.0	0.0	12.0	2,669.5	2,663.5
5	**Operations and Project Support**		551.8	32.9	0.0	32.9	584.8	568.3
6	**Settlement Adjustment**	2	0.0	(59.9)	0.0	(59.9)	(59.9)	(29.9)
7	**Nuclear - Excluding Asset Retirement Costs**		11,714.3	442.7	(134.6)	308.1	12,022.3	11,747.3
8	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
9	**Total**		14,021.2	442.7	(134.6)	308.1	14,329.3	14,054.3
	2023:							
10	**Darlington NGS**		2,974.7	382.8	0.0	382.8	3,357.5	3,166.1
11	**Darlington Refurbishment Program - Excluding D2O**		5,457.6	1.4	0.0	1.4	5,459.1	5,458.3
12	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	3	395.6	0.0	0.0	0.0	395.6	395.6
13	**Pickering NGS**		2,669.5	2.0	0.0	2.0	2,671.4	2,670.5
14	**Operations and Project Support**		584.8	114.8	0.0	114.8	699.6	670.1
15	**Settlement Adjustment**	2	(59.9)	(61.9)	0.0	(61.9)	(121.8)	(90.8)
16	**Nuclear - Excluding Asset Retirement Costs**		12,022.3	439.1	0.0	439.1	12,461.4	12,269.8
17	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
18	**Total**		14,329.3	439.1	0.0	439.1	14,768.4	14,576.7
	2024:							
19	**Darlington NGS**		3,357.5	493.8	0.0	493.8	3,851.3	3,660.4
20	**Darlington Refurbishment Program - Excluding D2O**		5,459.1	2,505.5	0.0	2,505.5	7,964.6	7,963.8
21	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	3	395.6	0.0	0.0	0.0	395.6	395.6
22	**Pickering NGS**		2,671.4	0.4	0.0	0.4	2,671.8	2,671.6
23	**Operations and Project Support**		699.6	29.2	0.0	29.2	728.8	714.2
24	**Settlement Adjustment**	2	(121.8)	(65.3)	0.0	(65.3)	(187.1)	(154.4)
25	**Nuclear - Excluding Asset Retirement Costs**		12,461.4	2,963.6	0.0	2,963.6	15,425.1	15,251.2
26	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
27	**Total**		14,768.4	2,963.6	0.0	2,963.6	17,732.0	17,558.2
	2025:							
28	**Darlington NGS**		3,851.3	476.6	0.0	476.6	4,327.9	4,081.1
29	**Darlington Refurbishment Program - Excluding D2O**		7,964.6	1,907.3	0.0	1,907.3	9,871.9	9,315.6
30	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	3	395.6	0.0	0.0	0.0	395.6	395.6
31	**Pickering NGS**		2,671.8	0.4	0.0	0.4	2,672.1	2,672.0
32	**Operations and Project Support**		728.8	48.2	0.0	48.2	777.0	752.9
33	**Settlement Adjustment**	2	(187.1)	(64.4)	0.0	(64.4)	(251.5)	(219.3)
34	**Nuclear - Excluding Asset Retirement Costs**		15,425.1	2,368.0	0.0	2,368.0	17,793.1	16,997.9
35	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
36	**Total**		17,732.0	2,368.0	0.0	2,368.0	20,100.1	19,304.9
	2026:							
37	**Darlington NGS**		4,327.9	367.8	0.0	367.8	4,695.7	4,511.8
38	**Darlington Refurbishment Program - Excluding D2O**		9,871.9	2,028.3	0.0	2,028.3	11,900.2	10,294.5
39	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	3	395.6	0.0	0.0	0.0	395.6	395.6
40	**Pickering NGS**		2,672.1	0.0	0.0	0.0	2,672.1	2,672.1
41	**Operations and Project Support**		777.0	11.4	0.0	11.4	788.4	782.7
42	**Settlement Adjustment**	2	(251.5)	(46.8)	0.0	(46.8)	(298.3)	(274.9)
43	**Nuclear - Excluding Asset Retirement Costs**		17,793.1	2,360.7	0.0	2,360.7	20,153.7	18,381.8
44	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
45	**Total**		20,100.1	2,360.7	0.0	2,360.7	22,460.7	20,688.8

For notes see Table 9a.

Table 9a
Notes to Table 9
Continuity of Property, Plant and Equipment - Nuclear ($M)

Notes:
1 Lines 1-2, 4-5, 8, 10-11, 13-14, 17, 19-20, 22-23, 26, 28-29, 31-32, 35, 37-38 and 40-41, 44 per Ex. B3-3-1, Table 2.
2 The 13% reduction to the Nuclear Operations forecasted in-service capital additions and the 5% reduction to Corporate Support Services forecasted in-service capital additions per OEB-approved settlement proposal (Decision and Order, Schedule A, P. 21) is calculated as:

		2022	2023	2024	2025	2026
(a)	Nuclear Operations (Ex. D2-1-3, Table 4b, cols. c, e, g, i, k, lines 14 and 26) x 13%	56.5	60.0	63.6	62.1	45.3
(b)	Corporate Support Services (Ex. D3-1-2, Table 5b, cols. c, e, g, i, k, lines 17, 19, 25 and 27) x 5%	3.4	1.9	1.7	2.4	1.5
(c)	Total (a) + (b)	59.9	61.9	65.3	64.4	46.8

3 Gross plant rate base amount of $395.6M for the D2O Storage Project is per line 3a below and reflects adjustments for the OEB Decision and Order findings as follows: disallowance of $94M in costs incurred as of October 2014, disallowance of carrying costs incurred from May 2017 to March 2020, and a March 2020 in-service date for the full amount of the approved costs (Decision and Order, PP. 35,52).

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
3a	Gross Plant Opening Balance (col. (a) per Ex. B3-3-1, Table 1, line 3, col. (a))	14.6	14.6	14.6	14.6	14.6	395.6	395.6	395.6	395.6	395.6	395.6
3b	In-Service Additions Using Approved In-Service Date, Prior to Disallowance (col. (e) is the sum of Ex. B3-3-1, Table 1, col. (b): line 3 + line 27 + line 35)	0.0	0.0	0.0	0.0	494.7	0.0	0.0	0.0	0.0	0.0	0.0
3c	Disallowance of $94M (per Decision and Order, p. 52)					(94.0)						
3d	Disallowance of Carrying Costs Incurred From May 2017 to March 2020 (per Decision and Order, p. 52)					(19.7)						
3e	Gross Plant Closing Balance (line: 3a + 3b + 3c + 3d)	14.6	14.6	14.6	14.6	395.6	395.6	395.6	395.6	395.6	395.6	395.6
3f	Gross Plant Rate Base Amount (line 3a + 3e) / 2 (Note #)	14.6	14.6	14.6	14.6	300.4	395.6	395.6	395.6	395.6	395.6	395.6

Based on March 27, 2020 in-service date, the in-service additions at line 3b and the disallowances at lines 3c and 3d are assigned a weighting of 9 months for purposes of the 2020 rate base.

Numbers may not add due to rounding.

Table 10
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)
Years Ending December 31, 2022 to 2026

Line No.	Prescribed Facility	Note	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
			(a)	(b)	(c)	(d)	(e)
		1					
	2022:						
1	**Darlington NGS**		697.9	101.2	0.0	799.2	748.5
2	**Darlington Refurbishment Program - Excluding D2O**	2	432.8	163.4	(34.8)	561.3	479.6
3	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	4	23.2	12.0	0.0	35.2	29.2
4	**Pickering NGS**		2,326.8	151.7	0.0	2,478.5	2,402.7
5	**Operations and Project Support**		399.0	38.1	0.0	437.0	418.0
6	**Settlement Adjustment**	3	0.0	(1.4)	0.0	(1.4)	(0.7)
7	**Nuclear - Excluding Asset Retirement Costs**		3,879.7	465.0	(34.8)	4,309.8	4,077.3
8	**Asset Retirement Costs**		2,023.9	82.2	0.0	2,106.1	2,065.0
9	**Total**		5,903.6	547.2	(34.8)	6,415.9	6,142.3
	2023:						
10	**Darlington NGS**		799.2	122.0	0.0	921.1	860.1
11	**Darlington Refurbishment Program - Excluding D2O**	2	561.3	163.4	0.0	724.7	643.0
12	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	4	35.2	12.0	0.0	47.2	41.2
13	**Pickering NGS**		2,478.5	78.1	0.0	2,556.6	2,517.6
14	**Operations and Project Support**		437.0	41.2	0.0	478.2	457.6
15	**Settlement Adjustment**	3	(1.4)	(4.1)	0.0	(5.5)	(3.5)
16	**Nuclear - Excluding Asset Retirement Costs**		4,309.8	412.4	0.0	4,722.3	4,516.0
17	**Asset Retirement Costs**		2,106.1	50.5	0.0	2,156.6	2,131.3
18	**Total**		6,415.9	462.9	0.0	6,878.8	6,647.4
	2024:						
19	**Darlington NGS**		921.1	142.5	0.0	1,063.6	992.4
20	**Darlington Refurbishment Program - Excluding D2O**	2	724.7	249.8	0.0	974.5	849.6
21	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	4	47.2	12.0	0.0	59.2	53.2
22	**Pickering NGS**		2,556.6	76.5	0.0	2,633.1	2,594.8
23	**Operations and Project Support**		478.2	42.9	0.0	521.2	499.7
24	**Settlement Adjustment**	3	(5.5)	(6.9)	0.0	(12.5)	(9.0)
25	**Nuclear - Excluding Asset Retirement Costs**		4,722.3	516.9	0.0	5,239.1	4,980.7
26	**Asset Retirement Costs**		2,156.6	50.5	0.0	2,207.1	2,181.8
27	**Total**		6,878.8	567.4	0.0	7,446.2	7,162.5
	2025:						
28	**Darlington NGS**		1,063.6	160.7	0.0	1,224.3	1,144.0
29	**Darlington Refurbishment Program - Excluding D2O**	2	974.5	298.9	0.0	1,273.4	1,124.0
30	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	4	59.2	12.0	0.0	71.2	65.2
31	**Pickering NGS**		2,633.1	0.4	0.0	2,633.4	2,633.3
32	**Operations and Project Support**		521.2	41.7	0.0	562.8	542.0
33	**Settlement Adjustment**	3	(12.5)	(9.4)	0.0	(21.8)	(17.2)
34	**Nuclear - Excluding Asset Retirement Costs**		5,239.1	504.3	0.0	5,743.4	5,491.2
35	**Asset Retirement Costs**		2,207.1	3.6	0.0	2,210.6	2,208.9
36	**Total**		7,446.2	507.8	0.0	7,954.0	7,700.1
	2026:						
37	**Darlington NGS**		1,224.3	173.2	0.0	1,397.5	1,310.9
38	**Darlington Refurbishment Program - Excluding D2O**	2	1,273.4	334.6	0.0	1,608.0	1,440.7
39	**Heavy Water Storage Facility (D2O) - OEB Adjusted**	4	71.2	12.0	0.0	83.2	77.2
40	**Pickering NGS**		2,633.4	0.0	0.0	2,633.4	2,633.4
41	**Operations and Project Support**		562.8	40.8	0.0	603.6	583.2
42	**Settlement Adjustment**	3	(21.8)	(11.8)	0.0	(33.6)	(27.7)
43	**Nuclear - Excluding Asset Retirement Costs**		5,743.4	548.8	0.0	6,292.2	6,017.8
44	**Asset Retirement Costs**		2,210.6	3.6	0.0	2,214.2	2,212.4
45	**Total**		7,954.0	552.4	0.0	8,506.4	8,230.2

For notes see Table 10a.

Table 10a
Notes to Table 10
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)

Notes:

1 Lines 1-2, 4-5, 8, 10-11, 13-14, 17, 19-20, 22-23, 26 per Ex. B3-4-1, Table 2. Lines 28-29, 31-32, 35, 37-38, 40-41, 44 per Ex. B3-4-1, Table 3, subject to a $1.5M downward adjustment to depreciation expense for Darlington Refurbishment Program - Excluding D2O for each of 2021-2026 identified at Ex. L-F4-01-Staff-269 and the revised adjustment at line 2, col. (c) per Note 2. The 2021 downward adjustment to depreciation expense for Darlington Refurbishment Program - Excluding D2O is reflected in the 2022 opening accumulated depreciation and amortization amount at line 2.

2 A downward adjustment of $34.8M is calculated as follows and is assigned a 12/12 weighting: $36.3M per Ex. L-B1-01-Staff-024, Chart 1 less $1.5M downward adjustment to depreciation expense for 2021 that is refelcted in the 2022 opening accumulated depreciation and amortization amount per Note 1.

3 Represents the depreciation impact of the 13% reduction in Nuclear Operations and 5% reduction in Corporate Support Services forecast capital in-service additions at App. A, Table 9, lines 6, 15, 24, 33 and 42. The depreciation impact is calculated assuming the 13% in-service reduction is appiled to the Nuclear Operations component of each of Darlington NGS, Pickering NGS and Operations and Project Support and the 5% in-service reduction is applied to the Corporate Support Services component of each of Darlington NGS, Pickering NGS and Operations and Project Support.

4 Depreciation and amortization amounts at Lines 3, 12, 21, 30, and 39 are the sum of line 4b and line 4c, for each respective year, in the table below. These amounts reflect adjustments for the OEB Decision and Order findings as follows: disallowance of $94M in costs incurred as of October 2014, disallowance of carrying costs incurred from May 2017 to March 2020, and a March 2020 in-service date for the full amount of the approved costs (Decision and Order, PP. 35,52). Depreciation and amortization amounts are calculated over an average service life to December 31, 2052, consistent with OPG's application.

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
4a	Accumulated Depreciation and Amortization Opening Balance (col. (a) per Ex. B3-4-1, Table 1, line 3, col. (a))	0.5	0.9	1.3	1.7	2.0	11.2	23.2	35.2	47.2	59.2	71.2
4b	Depreciation and Amortization Using Approved In-Service Date, Prior to Disallowance (cols. (a) to (d) per Ex. B3-4-1, Table 1, line 3, col. (b). Cols. (e) to (k) per Note #)	0.4	0.4	0.4	0.4	11.7	15.5	15.5	15.5	15.5	15.5	15.5
4c	Depreciation and Amortization Adjustment for Project Cost Disallowance (Note &)	0.0	0.0	0.0	0.0	(2.6)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)
4d	Accumulated Depreciation and Amortization Closing Balance (line 4a + 4b + 4c)	0.9	1.3	1.7	2.0	11.2	23.2	35.2	47.2	59.2	71.2	83.2
4e	Accumulated Depreciation and Amortization Rate Base Amount (line 4a + line 4d)/2	0.7	1.1	1.5	1.9	6.6	17.2	29.2	41.2	53.2	65.2	77.2

Depreciation and amortiation amounts using approved in-service date of March 2020, prior to disallowance, are calculated on in-service additions of $494.7M in 2020 (PAO App. A, Table 9a, line 3b) and opening gross plant balance of $14.6M in 2020 (PAO App. A, Table 9a, line 3a), as follows:

1#	March 2020 In-service Amount Prior to Disallowance (PAO App. A, Table 9a, Note 3, line 3b)	494.7
2#	Annual Depreciation on 2020 In-service Amount Prior to Disallowance (line 1# / 32.75 yrs)	15.1
3#	Depreciation on Opening Balance (line 4b, col. (a))	0.4
4#	Total Annual Depreciation Prior to Disallowances (2021-2026) (line 2# + line 3#)	15.5
5#	Depreciation for 2020 Prior to Disallowance (line 2# * 9/12 mos + line 3#)	11.7

& The impact to depreciation and amortization amounts from disallowed project costs is calculated as follows:

1&	Disallowance of $94M (PAO App. A, Table 9a, Note 3, line 3c)	(94.0)
2&	Disallowance of Carrying Costs Incurred From May 2017 to March 2020 (PAO App. A, Table 9a, Note 3, line 3c)	(19.7)
3&	Annual Depreciation and Amortization Adjustment ((line 1& + line 2&) / 32.75 yrs)	(3.5)
4&	Depreciation and Amortization Adjustment for 2020 (line 3& * 9/12 mos.)	(2.6)

Table 11
Summary of Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2022

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	50.8	0.6%	0.47%	2.9
2	**Existing/Planned Long-Term Debt**	1, 2	2,000.0	23.5%	3.61%	72.1
3	**Other Long-Term Debt Provision**	1	2,638.9	30.9%	3.61%	95.1
4	**Total Debt**	3	4,689.7	55.0%	3.63%	170.1
5	**Common Equity at Long-Term Debt Rate**	1, 4	128.8	1.5%	3.61%	4.6
5a	**Common Equity at ROE Rate**	1, 8	3,708.2	43.5%	8.66%	321.1
5b	**Total Equity**	3	3,837.0	45.0%	8.49%	325.8
6	**Rate Base Financed by Capital Structure**	5	8,526.7	99.1%	5.82%	495.9
7	**Adjustment for Lesser of UNL or ARC**	1, 6	73.6	0.9%	4.89%	3.6
8	**Rate Base**	7	8,600.3	100%	5.81%	499.5

Notes:

1 Long- and short-term debt cost rates, return on equity rate and cost rate for adjustment for Lesser of UNL or ARC as proposed by OPG, per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6, Ex. JT3.6, Att. 1, Table 1, line 1, col. (f) and cash working capital amount and materials and supplies applicable to regulated hydroelectric facilities.

3 The Debt / Equity ratio of 55% debt, 45% equity as per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). Col. (a) is calculated as 45% of PAO App. A, Table 16, line 40, col. (e) less PAO App. A, Table 16c, line 8, col. (e).

5 Col. (a) is the sum of lines 4 (Total Debt) and 5b (Total Equity).

6 Col. (a) from Ex. C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Col. (a) is per PAO App. A, Table 1, line 4, col. (c).

8 The ROE rate of 8.66% in col. (c) is per the OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.

Table 12
Summary of Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2023

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	50.4	0.6%	0.78%	3.0
2	**Existing/Planned Long-Term Debt**	1, 2	2,089.8	24.3%	3.49%	72.8
3	**Other Long-Term Debt Provision**	1	2,598.1	30.2%	3.49%	90.5
4	**Total Debt**	3	4,738.2	55.0%	3.51%	166.4
5	**Common Equity at Long-Term Debt Rate**	1, 4	113.0	1.3%	3.49%	3.9
5a	**Common Equity at ROE Rate**	1, 8	3,763.7	43.7%	8.66%	325.9
5b	**Total Equity**	3	3,876.7	45%	8.51%	329.9
6	**Rate Base Financed by Capital Structure**	5	8,615.0	100.0%	5.76%	496.3
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	8,615.0	100%	5.76%	496.3

Notes:

1 Long- and short-term debt cost rates, return on equity rate and cost rate for adjustment for Lesser of UNL or ARC as proposed by OPG, per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6, Ex. JT3.6, Att. 1, Table 1, line 1, col. (f) and cash working capital amount and materials and supplies applicable to regulated hydroelectric facilities.

3 The Debt / Equity ratio of 55% debt, 45% equity as per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). Col. (a) is calculated as 45% of PAO App. A, Table 16, line 40, col. (e) less PAO App. A, Table 16c, line 16, col. (e).

5 Col. (a) is the sum of lines 4 (Total Debt) and 5b (Total Equity).

6 Principal from Ex. C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Col. (a) is per PAO App. A, Table 2, line 4, col. (c).

8 The ROE rate of 8.66% in col. (c) is per the OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.

Table 13
Summary of Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2024

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	55.9	0.5%	1.16%	3.6
2	**Existing/Planned Long-Term Debt**	1, 2	2,161.6	19.6%	3.61%	78.1
3	**Other Long-Term Debt Provision**	1	3,850.9	34.9%	3.61%	139.2
4	**Total Debt**	3	6,068.4	55.0%	3.64%	220.8
5	**Common Equity at Long-Term Debt Rate**	1, 4	97.6	0.9%	3.61%	3.5
5a	**Common Equity at ROE Rate**	1, 8	4,867.4	44.1%	8.66%	421.5
5b	**Total Equity**	3	4,965.0	45%	8.56%	425.0
6	**Rate Base Financed by Capital Structure**	5	11,033.4	100.0%	5.85%	645.9
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	11,033.4	100%	5.85%	645.9

Notes:

1 Long- and short-term debt cost rates, return on equity rate and cost rate for adjustment for Lesser of UNL or ARC as proposed by OPG, per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6, Ex. JT3.6, Att. 1, Table 1, line 1, col. (f) and cash working capital amount and materials and supplies applicable to regulated hydroelectric facilities.

3 The Debt / Equity ratio of 55% debt, 45% equity as per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). Col. (a) is calculated as 45% of PAO App. A, Table 16, line 40, col. (e) less PAO App. A, Table 16c, line 24, col. (e).

5 Col. (a) is the sum of lines 4 (Total Debt) and 5b (Total Equity).

6 Principal from Ex. C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Col. (a) is per PAO App. A, Table 3, line 4, col. (c).

8 The ROE rate of 8.66% in col. (c) is per the OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.

Table 14
Summary of Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2025

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	57.3	0.5%	1.66%	3.9
2	**Existing/Planned Long-Term Debt**	1, 2	2,170.4	17.8%	3.65%	79.3
3	**Other Long-Term Debt Provision**	1	4,476.1	36.7%	3.65%	163.5
4	**Total Debt**	3	6,703.8	55.0%	3.68%	246.8
5	**Common Equity at Long-Term Debt Rate**	1, 4	84.1	0.7%	3.65%	3.1
5a	**Common Equity at ROE Rate**	1, 8	5,400.9	44.3%	8.66%	467.7
5b	**Total Equity**	3	5,485.0	45%	8.58%	470.8
6	**Rate Base Financed by Capital Structure**	5	12,188.8	100.0%	5.89%	717.5
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	12,188.8	100%	5.89%	717.5

Notes:

1 Long- and short-term debt cost rates, return on equity rate and cost rate for adjustment for Lesser of UNL or ARC as proposed by OPG, per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6, Ex. JT3.6, Att. 1, Table 1, line 1, col. (f) and cash working capital amount and materials and supplies applicable to regulated hydroelectric facilities.

3 The Debt / Equity ratio of 55% debt, 45% equity as per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). Col. (a) is calculated as 45% of PAO App. A, Table 16, line 40, col. (e) less PAO App. A, Table 16c, line 32, col. (e).

5 Col. (a) is the sum of lines 4 (Total Debt) and 5b (Total Equity).

6 Principal from Ex. C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Col. (a) is per PAO App. A, Table 4, line 4, col. (c).

8 The ROE rate of 8.66% in col. (c) is per the OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.

Table 15
Summary of Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2026

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	57.9	0.4%	2.23%	4.3
2	**Existing/Planned Long-Term Debt**	1, 2	2,186.7	16.8%	3.65%	79.9
3	**Other Long-Term Debt Provision**	1	4,900.9	37.7%	3.65%	179.1
4	**Total Debt**	3	7,145.5	55.0%	3.68%	263.3
5	**Common Equity at Long-Term Debt Rate**	1, 4	73.0	0.6%	3.65%	2.7
5a	**Common Equity at ROE Rate**	1, 8	5,773.4	44.4%	8.66%	500.0
5b	**Total Equity**	3	5,846.3	45%	8.60%	502.6
6	**Rate Base Financed by Capital Structure**	5	12,991.8	100.0%	5.90%	765.9
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	12,991.8	100%	5.90%	765.9

Notes:

1 Long- and short-term debt cost rates, return on equity rate and cost rate for adjustment for Lesser of UNL or ARC as proposed by OPG, per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6, Ex. JT3.6, Att. 1, Table 1, line 1, col. (f) and cash working capital amount and materials and supplies applicable to regulated hydroelectric facilities.

3 The Debt / Equity ratio of 55% debt, 45% equity as per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 24)

4 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 23). Col. (a) is calculated as 45% of PAO App. A, Table 16, line 40, col. (e) less PAO App. A, Table 16c, line 40, col. (e).

5 Col. (a) is the sum of lines 4 (Total Debt) and 5b (Total Equity).

6 Principal from Ex. C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Col. (a) is per PAO App. A, Table 5, line 4, col. (c).

8 The ROE rate of 8.66% in col. (c) is per the OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.

Numbers may not add due to rounding.

Table 16
Continuity of Property, Plant and Equipment Subject to Long-Term Debt Rate- Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility Category	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
			Note 1				
	2017 Actual:						
1	**Darlington NGS**	0.0	(43.2)	0.0	(43.2)	(43.2)	(21.6)
2	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0	0.0
3	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Pickering NGS**	0.0	(12.7)	0.0	(12.7)	(12.7)	(6.4)
5	**Operations and Project Support**	0.0	44.9	0.0	44.9	44.9	22.5
6	**Nuclear - Excluding Asset Retirement Costs**	0.0	(11.0)	0.0	(11.0)	(11.0)	(5.5)
7	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0	0.0
8	**Total**	0.0	(11.0)	0.0	(11.0)	(11.0)	(5.5)
	2018 Actual:						
9	**Darlington NGS**	(43.2)	44.3	0.0	44.3	1.1	(21.1)
10	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0	0.0
11	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0	0.0
12	**Pickering NGS**	(12.7)	(12.3)	0.0	(12.3)	(25.0)	(18.9)
13	**Operations and Project Support**	44.9	38.0	0.0	38.0	82.9	63.9
14	**Nuclear - Excluding Asset Retirement Costs**	(11.0)	70.0	0.0	70.0	59.0	24.0
15	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total**	(11.0)	70.0	0.0	70.0	59.0	24.0
	2019 Actual:						
17	**Darlington NGS**	1.1	(36.8)	0.0	(36.8)	(35.8)	(17.3)
18	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0	0.0
19	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0	0.0
20	**Pickering NGS**	(25.0)	20.0	0.0	20.0	(5.0)	(15.0)
21	**Operations and Project Support**	82.9	11.7	0.0	11.7	94.6	88.8
22	**Nuclear - Excluding Asset Retirement Costs**	59.0	(5.1)	0.0	(5.1)	53.9	56.4
23	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0	0.0
24	**Total**	59.0	(5.1)	0.0	(5.1)	53.9	56.4
	2020 Budget:						
25	**Darlington NGS**	(35.8)	24.8	0.0	24.8	(10.9)	(23.3)
26	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0	0.0
27	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0	0.0
28	**Pickering NGS**	(5.0)	30.1	0.0	30.1	25.1	10.1
29	**Operations and Project Support**	94.6	34.2	0.0	34.2	128.8	111.7
30	**Nuclear - Excluding Asset Retirement Costs**	53.9	89.2	0.0	89.2	143.1	98.5
31	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0	0.0
32	**Total**	53.9	89.2	0.0	89.2	143.1	98.5
	2021 Budget:						
33	**Darlington NGS**	(10.9)	142.2	0.0	142.2	131.3	60.2
34	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0	0.0
35	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0	0.0
36	**Pickering NGS**	25.1	(2.4)	0.0	(2.4)	22.7	23.9
37	**Operations and Project Support**	128.8	75.2	0.0	75.2	204.0	166.4
38	**Nuclear - Excluding Asset Retirement Costs**	143.1	215.0	0.0	215.0	358.0	250.5
39	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total**	143.1	215.0	0.0	215.0	358.0	250.5

Notes: Refer to Table 16d

Numbers may not add due to rounding.

Table 16b
Continuity of Accumulated Depreciation and Amortization for In-service Amounts Subject to Long-Term Debt Rate- Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility Category	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
			Note 2			
	2017 Actual:					
1	**Darlington NGS**	0.0	(0.7)	0.0	(0.7)	(0.4)
2	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
3	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
4	**Pickering NGS**	0.0	(0.8)	0.0	(0.8)	(0.4)
5	**Operations and Project Support**	0.0	2.2	0.0	2.2	1.1
6	**Nuclear - Excluding Asset Retirement Costs**	0.0	0.7	0.0	0.7	0.3
7	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
8	**Total**	0.0	0.7	0.0	0.7	0.3
	2018 Actual:					
9	**Darlington NGS**	(0.7)	(0.7)	0.0	(1.4)	(1.1)
10	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
11	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
12	**Pickering NGS**	(0.8)	(2.6)	0.0	(3.5)	(2.2)
13	**Operations and Project Support**	2.2	6.6	0.0	8.9	5.6
14	**Nuclear - Excluding Asset Retirement Costs**	0.7	3.3	0.0	3.9	2.3
15	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
16	**Total**	0.7	3.3	0.0	3.9	2.3
	2019 Actual:					
17	**Darlington NGS**	(1.4)	(0.6)	0.0	(2.0)	(1.7)
18	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
19	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
20	**Pickering NGS**	(3.5)	(1.8)	0.0	(5.3)	(4.4)
21	**Operations and Project Support**	8.9	9.6	0.0	18.5	13.7
22	**Nuclear - Excluding Asset Retirement Costs**	3.9	7.3	0.0	11.2	7.6
23	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
24	**Total**	3.9	7.3	0.0	11.2	7.6
	2020 Budget:					
25	**Darlington NGS**	(2.0)	(0.8)	0.0	(2.8)	(2.4)
26	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
27	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
28	**Pickering NGS**	(5.3)	3.4	0.0	(1.9)	(3.6)
29	**Operations and Project Support**	18.5	12.3	0.0	30.8	24.6
30	**Nuclear - Excluding Asset Retirement Costs**	11.2	14.9	0.0	26.1	18.7
31	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
32	**Total**	11.2	14.9	0.0	26.1	18.7
	2021 Budget:					
33	**Darlington NGS**	(2.8)	2.0	0.0	(0.9)	(1.8)
34	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
35	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
36	**Pickering NGS**	(1.9)	6.4	0.0	4.5	1.3
37	**Operations and Project Support**	30.8	19.6	0.0	50.3	40.5
38	**Nuclear - Excluding Asset Retirement Costs**	26.1	27.9	0.0	54.0	40.0
39	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
40	**Total**	26.1	27.9	0.0	54.0	40.0

Notes: Refer to Table 16d

Numbers may not add due to rounding.

Table 16c
Continuity of Accumulated Depreciation and Amortization for In-service Amounts Subject to Long-Term Debt Rate- Nuclear ($M)
Years Ending December 31, 2022 to 2026

Line No.	Prescribed Facility Category	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
			Note 2			
	2022 Plan:					
1	**Darlington NGS**	(0.9)	4.3	0.0	3.4	1.3
2	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
3	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
4	**Pickering NGS**	4.5	6.1	0.0	10.6	7.6
5	**Operations and Project Support**	50.3	25.1	0.0	75.5	62.9
6	**Nuclear - Excluding Asset Retirement Costs**	54.0	35.5	0.0	89.5	71.7
7	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
8	**Total**	54.0	35.5	0.0	89.5	71.7
	2023 Plan:					
9	**Darlington NGS**	3.4	4.3	0.0	7.7	5.6
10	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
11	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
12	**Pickering NGS**	10.6	6.1	0.0	16.7	13.6
13	**Operations and Project Support**	75.5	24.6	0.0	100.1	87.8
14	**Nuclear - Excluding Asset Retirement Costs**	89.5	34.9	0.0	124.4	106.9
15	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
16	**Total**	89.5	34.9	0.0	124.4	106.9
	2024 Plan:					
17	**Darlington NGS**	7.7	4.3	0.0	12.0	9.8
18	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
19	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
20	**Pickering NGS**	16.7	6.1	0.0	22.7	19.7
21	**Operations and Project Support**	100.1	23.2	0.0	123.3	111.7
22	**Nuclear - Excluding Asset Retirement Costs**	124.4	33.5	0.0	157.9	141.2
23	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
24	**Total**	124.4	33.5	0.0	157.9	141.2
	2025 Plan:					
25	**Darlington NGS**	12.0	4.3	0.0	16.2	14.1
26	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
27	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
28	**Pickering NGS**	22.7	0.0	0.0	22.7	22.7
29	**Operations and Project Support**	123.3	22.3	0.0	145.5	134.4
30	**Nuclear - Excluding Asset Retirement Costs**	157.9	26.5	0.0	184.5	171.2
31	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
32	**Total**	157.9	26.5	0.0	184.5	171.2
	2026 Plan:					
33	**Darlington NGS**	16.2	4.3	0.0	20.5	18.4
34	**Darlington Refurbishment Program - Excluding D2O**	0.0	0.0	0.0	0.0	0.0
35	**Heavy Water Storage Facility (D2O)**	0.0	0.0	0.0	0.0	0.0
36	**Pickering NGS**	22.7	0.0	0.0	22.7	22.7
37	**Operations and Project Support**	145.5	18.6	0.0	164.2	154.9
38	**Nuclear - Excluding Asset Retirement Costs**	184.5	22.9	0.0	207.4	195.9
39	**Asset Retirement Costs**	0.0	0.0	0.0	0.0	0.0
40	**Total**	184.5	22.9	0.0	207.4	195.9

Notes: Refer to Table 16d

Table 16d
Notes to Table 16, 16b and 16c
Continuity of Property, Plant and Equipment Subject to Long-Term Debt Rate- Nuclear ($M)

Notes:
1 In-service capital additions for 2017-2021 forming part of the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 are calculated as follows per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 36):

Line no	Facility	Reference	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Plan	Total
	In-service Capital Additions Variance to EB-2016-0152, Ex. J21.1, Attachment 2:							
1	Darlington NGS	EB-2020-0290 Ex. B3-3-1, Table 1, col. (b), lines 9, 17, 25, 33, 41 less EB-2016-0152 PAO App. A, Table 9, col. (b), lines 1, 11, 21, 31, 41	(57.2)	31.1	(54.4)	14.8	135.0	69.3
2	Pickering NGS	EB-2020-0290 Ex. B3-3-1, Table 1, col. b) lines 12, 20, 28, 36, 44 less EB-2016-0152 PAO, App. A, Table 9 col. (b) lines 3, 13, 23, 33, 43	(23.4)	(17.2)	18.4	28.2	(4.0)	2.1
3	Operations and Project Support	EB-2020-0290 Ex. B3-3-1, Table 1, col. (b), lines 13, 21, 29, 37, 45 less EB-2016-0152 PAO, App. A, Table 9, col. (b), lines 4, 14, 24, 34, 44	44.1	37.5	11.2	33.8	74.7	201.2
4	Total		(36.5)	51.4	(24.8)	76.7	205.8	272.6
	50% of EB-2016-0152 Forecast In-service Additions Reduction:							
5	Darlington NGS	EB-2016-0152 PAO, App. A, Table 9, col. (b), lines 1, 11, 21, 31, 41 x 50%	14.0	13.2	17.6	10.1	7.2	62.0
6	Pickering NGS	EB-2016-0152 PAO, App. A, Table 9. col. (b), lines 3, 13, 23, 33, 43 x 50%	10.6	4.9	1.6	1.9	1.6	20.6
7	Operations and Project Support	EB-2016-0152 PAO, App. A, Table 9, col. (b), lines 4, 14, 24, 34, 44 x 50%	0.8	0.5	0.5	0.5	0.5	2.8
8	Total		25.4	18.6	19.7	12.5	9.2	85.4
	In-service Capital Additions Subject to Return on Equity at the Long-Term Debt Rate:							
9	Darlington NGS	Line 1 + Line 5	**(43.2)**	**44.3**	**(36.8)**	**24.8**	**142.2**	**131.3**
10	Pickering NGS	Line 2 + Line 6	**(12.7)**	**(12.3)**	**20.0**	**30.1**	**(2.4)**	**22.7**
11	Operations and Project Support	Line 3 + Line 7	**44.9**	**38.0**	**11.7**	**34.2**	**75.2**	**204.0**
12	**Total**		**(11.0)**	**70.0**	**(5.1)**	**89.2**	**215.0**	**358.0**

2 Represents the depreciation impact associated with in-service capital additions for 2017-2021 forming part of the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 (App. A, Table 16, col. (b)). The depreciation impact is calculated by applying the corresponding weighted average depreciation rates to each of Darlington NGS, Pickering NGS and Operations and Project Support, inclusive of Nuclear Operations and Corporate Support Services capital.

Table 17
2022 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	236.7	(34.8)	201.9
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	553.0	(5.8)	547.2
3	**Nuclear Waste Management Expenses**		57.3	0.0	57.3
4	**Receipts from Nuclear Segregated Funds**		82.5	0.0	82.5
5	**Pension and OPEB Accrual**		311.7	0.0	311.7
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		28.0	0.7	28.7
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Act**		152.9	0.0	152.9
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(1.6)	0.0	(1.6)
9	**Reversal of Niagara Tunnel Disallowance**		0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**		3.6	0.0	3.6
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		17.4	0.0	17.4
12	**Other**	5	73.2	(0.5)	72.6
13	**Total Additions**		1,278.0	(5.6)	1,272.3
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	839.5	(17.7)	821.8
15	**Cash Expenditures for Nuclear Waste & Decommissioning**		269.6	0.0	269.6
16	**Contributions to Nuclear Segregated Funds and Earnings**		244.4	0.0	244.4
17	**Pension Plan Contributions**		148.5	0.0	148.5
18	**OPEB Payments**		98.0	0.0	98.0
19	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
20	**Deductible SR&ED Qualifying Expenditures**		35.0	0.0	35.0
21	**Other**		0.0	0.0	0.0
22	**Total Deductions**		1,634.9	(17.7)	1,617.2
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		(120.3)	(22.7)	(143.0)
24	**Tax Loss Carry-Over / (Applied)**	7	120.3	22.7	143.0
25	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 23 + line 24)		0.0	0.0	0.0
26	**Regulatory Income Taxes - Federal** (line 24 x line 30)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Provincial** (line 24 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.5)	0.0	(16.5)
29	**Total Regulatory Income Taxes** (line 26 + line 27 + line 28)		(16.5)	0.0	(16.5)
	Income Tax Rate:				
30	**Federal Tax**		15.00%	0.00%	15.00%
31	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
32	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 17a.

Numbers may not add due to rounding.

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Draft Payment Amounts Order
Appendix A
Table 17a

Table 17a
Notes to Table 17
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities
Year Ending December 31, 2022

Notes:
1 As per Ex. F4-2-1, Table 3a, cols. (a) - (e) updated on March 12, 2021.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	PAO App. A, Table 1, line 12 and line 12a	360.6	(34.8)	325.8
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 1, line 20	(45.6)	0.0	(45.6)
3a		line 1a - line 2a	406.2	(34.8)	371.4
4a	Additions for Regulatory Tax Purposes	line 13	1,278.0	(5.6)	1,272.3
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	PAO App. D Table 1, Lines 15-17	152.9	0.0	152.9
6a	Deductions for Regulatory Tax Purposes	line 22	1,634.9	(17.7)	1,617.2
7a		line 3a + line 4a - line 5a - line 6a	(103.7)	(22.7)	(126.4)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	(18.0)	(3.4)	(21.4)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	(12.0)	(2.3)	(14.3)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.5)	0.0	(16.5)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(46.6)	(5.7)	(52.3)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	18.0	3.4	21.4
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	12.0	2.3	14.3
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	30.1	5.7	35.7
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	(0.0)	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	(0.0)	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.5)	0.0	(16.5)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.5)	0.0	(16.5)
19a	After Tax Return on Equity	line 1a	360.6	(34.8)	325.8
20a	Less: Bruce Lease Net Revenues	line 2a	(45.6)	0.0	(45.6)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	152.9	0.0	152.9
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(16.5)	0.0	(16.5)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	236.7	(34.8)	201.9

2a Amounts from Ex. F4-2-1, Table 3c, updated on March 12, 2021.
3 Adjustment to After Tax ROE for Prescribed Nuclear Facilities per PAO App. A, Table 1, col. (c), lines 12 and 12a.
4 OEB Approved is per PAO App. A, Table 1, col. (c), line 17.
5 Reflects the impact of adjusted fuel expense per PAO App. A, Table 1a, Note 6, line (g) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year.
6 Adjusted to reflect changes to Capital Cost Allowance resulting from adjustments to capital in-service additions included in the OEB approved settlement proposal (Decision and Order, Schedule A, P. 21) and the OEB's disallowance of D2O Storage Project costs (OEB Decision and Order, P.35).
7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR term, with any remaining tax losses carried forward to future test periods. See PAO App. A, Table 22, col. (a), line 4 for loss carryforward.

Numbers may not add due to rounding.

Table 18

2023 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	236.0	(36.6)	199.3
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	471.5	(8.6)	462.9
3	**Nuclear Waste Management Expenses**		68.9	0.0	68.9
4	**Receipts from Nuclear Segregated Funds**		104.3	0.0	104.3
5	**Pension and OPEB Accrual**		294.1	0.0	294.1
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		28.0	0.7	28.7
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Act**		152.9	0.0	152.9
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(1.6)	0.0	(1.6)
9	**Reversal of Niagara Tunnel Disallowance**		0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.5	0.0	16.5
12	**Other**	5	76.2	0.1	76.3
13	**Total Additions**		1,210.9	(7.8)	1,203.1
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	878.8	(22.4)	856.4
15	**Cash Expenditures for Nuclear Waste & Decommissioning**		262.7	0.0	262.7
16	**Contributions to Nuclear Segregated Funds and Earnings**		100.6	0.0	100.6
17	**Pension Plan Contributions**		151.5	0.0	151.5
18	**OPEB Payments**		101.4	0.0	101.4
19	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
20	**Deductible SR&ED Qualifying Expenditures**		34.2	0.0	34.2
21	**Other**		0.0	0.0	0.0
22	**Total Deductions**		1,529.2	(22.4)	1,506.8
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		(82.3)	(22.0)	(104.3)
24	**Tax Loss Carry-Over / (Applied)**	7	82.3	22.0	104.3
25	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 23 + line 24)		0.0	0.0	0.0
26	**Regulatory Income Taxes - Federal** (line 24 x line 30)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Provincial** (line 24 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.3)	0.0	(16.3)
29	**Total Regulatory Income Taxes** (line 26 + line 27 + line 28)		(16.3)	0.0	(16.3)
	Income Tax Rate:				
30	**Federal Tax**		15.00%	0.00%	15.00%
31	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
32	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 18a.

Table 18a
Notes to Table 18
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities
Year Ending December 31, 2023

Notes:
1 As per Ex. F4-2-1, Table 3a, col. (a) - (e) updated on March 12, 2021.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	PAO App. A, Table 2, line 12 and line 12a	366.5	(36.6)	329.9
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 2, line 20	(38.7)	0.0	(38.7)
3a		line 1a - line 2a	405.2	(36.6)	368.6
4a	Additions for Regulatory Tax Purposes	line 13	1,210.9	(7.8)	1,203.1
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	PAO App. D Table 1, Lines 15-17	152.9	0.0	152.9
6a	Deductions for Regulatory Tax Purposes	line 22	1,529.2	(22.4)	1,506.8
7a		line 3a + line 4a - line 5a - line 6a	(66.0)	(22.0)	(88.0)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	(12.3)	(3.3)	(15.6)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	(8.2)	(2.2)	(10.4)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.3)	0.0	(16.3)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(36.9)	(5.5)	(42.4)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	12.3	3.3	15.6
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	8.2	2.2	10.4
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	20.6	5.5	26.1
					0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.3)	0.0	(16.3)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.3)	0.0	(16.3)
19a	After Tax Return on Equity	line 1a	366.5	(36.6)	329.9
20a	Less: Bruce Lease Net Revenues	line 2a	(38.7)	0.0	(38.7)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	152.9	0.0	152.9
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(16.3)	0.0	(16.3)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	236.0	(36.6)	199.3

2a Amounts from Ex. F4-2-1, Table 3c, updated on March 12, 2021.
3 Adjustment to After Tax ROE for Prescribed Nuclear Facilities per PAO App. A, Table 2, col. (c), lines 12 and 12a.
4 OEB Approved is per PAO App. A, Table 2, col. (c), line 17.
5 Reflects the impact of adjusted fuel expense per PAO App. A, Table 2a, Note 6, line (g) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year.
6 Adjusted to reflect changes to Capital Cost Allowance resulting from adjustments to capital in-service additions included in the OEB approved settlement proposal (Decision and Order, Schedule A, P. 21) and the OEB's disallowance of D2O Storage Project costs (OEB Decision and Order, P.35).

7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR term, with any remaining tax losses carried forward to future test periods. See PAO App. A, Table 22, col. (b), line 4 for loss carryforward.

Table 19

2024 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	348.4	(44.5)	303.9
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	578.7	(11.4)	567.4
3	**Nuclear Waste Management Expenses**		72.3	0.0	72.3
4	**Receipts from Nuclear Segregated Funds**		136.4	0.0	136.4
5	**Pension and OPEB Accrual**		272.8	0.0	272.8
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		28.0	0.7	28.7
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Act**		152.9	0.0	152.9
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(1.6)	0.0	(1.6)
9	**Reversal of Niagara Tunnel Disallowance**		0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.3	0.0	16.3
12	**Other**	5	35.5	0.5	36.0
13	**Total Additions**		1,291.4	(10.2)	1,281.3
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	834.1	(23.7)	810.4
15	**Cash Expenditures for Nuclear Waste & Decommissioning**		306.1	0.0	306.1
16	**Contributions to Nuclear Segregated Funds and Earnings**		100.6	0.0	100.6
17	**Pension Plan Contributions**		152.1	0.0	152.1
18	**OPEB Payments**		103.2	0.0	103.2
19	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
20	**Deductible SR&ED Qualifying Expenditures**		34.4	0.0	34.4
21	**Other**		6.1	0.0	6.1
22	**Total Deductions**		1,536.7	(23.7)	1,513.0
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		103.2	(31.0)	72.1
24	**Tax Loss Carry-Over / (Applied)**	7	(103.2)	31.0	(72.1)
25	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 23 + line 24)		0.0	0.0	0.0
26	**Regulatory Income Taxes - Federal** (line 24 x line 30)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Provincial** (line 24 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.4)	0.0	(16.4)
29	**Total Regulatory Income Taxes** (line 26 + line 27 + line 28)		(16.4)	0.0	(16.4)
	Income Tax Rate:				
30	**Federal Tax**		15.00%	0.00%	15.00%
31	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
32	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 19a.

Table 19a
Notes to Table 19
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities
Year Ending December 31, 2024

Notes:
1 As per Ex. F4-2-1, Table 3a, col. (a) - (e) updated on March 12, 2021.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	PAO App. A, Table 3, line 12 and line 12a	469.6	(44.5)	425.0
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 3, line 20	(48.1)	0.0	(48.1)
3a		line 1a - line 2a	517.7	(44.5)	473.2
4a	Additions for Regulatory Tax Purposes	line 13	1,291.4	(10.2)	1,281.3
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	PAO App. D Table 1, Lines 15-17	152.9	0.0	152.9
6a	Deductions for Regulatory Tax Purposes	line 22	1,536.7	(23.7)	1,513.0
7a		line 3a + line 4a - line 5a - line 6a	119.6	(31.0)	88.5
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	15.5	(4.7)	10.8
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	10.3	(3.1)	7.2
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.4)	0.0	(16.4)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	9.4	(7.8)	1.6
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(15.5)	4.7	(10.8)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(10.3)	3.1	(7.2)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(25.8)	7.8	(18.0)
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	(0.0)	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	(0.0)	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.4)	0.0	(16.4)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.4)	0.0	(16.4)
19a	After Tax Return on Equity	line 1a	469.6	(44.5)	425.0
20a	Less: Bruce Lease Net Revenues	line 2a	(48.1)	0.0	(48.1)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	152.9	0.0	152.9
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(16.4)	0.0	(16.4)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	348.4	(44.5)	303.9

2a Amounts from Ex. F4-2-1, Table 3c, updated on March 12, 2021.
3 Adjustment to After Tax ROE for Prescribed Nuclear Facilities per PAO App. A, Table 3, col. (c), lines 12 and 12a.
4 OEB Approved is per PAO App. A, Table 3, col. (c), line 17.
5 Reflects the impact of adjusted fuel expense per PAO App. A, Table 3a, Note 6, line (g) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year.
6 Adjusted to reflect changes to Capital Cost Allowance resulting from adjustments to capital in-service additions included in the OEB approved settlement proposal (Decision and Order, Schedule A, P. 21) and the OEB's disallowance of D2O Storage Project costs (OEB Decision and Order, P.35).

7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR term, with any remaining tax losses carried forward to future test periods. See PAO App. A, Table 22, col. (c), line 3 for loss applied.

Table 20
2025 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	441.5	(49.1)	392.3
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	521.6	(13.8)	507.8
3	**Nuclear Waste Management Expenses**		52.1	0.0	52.1
4	**Receipts from Nuclear Segregated Funds**		284.2	0.0	284.2
5	**Pension and OPEB Accrual**		228.2	0.0	228.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		21.1	0.0	21.1
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Act**		108.8	0.0	108.8
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
9	**Reversal of Niagara Tunnel Disallowance**		0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.3	0.0	16.3
12	**Other**	5	4.4	0.6	5.0
13	**Total Additions**		1,236.7	(13.2)	1,223.5
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	860.2	(27.4)	832.8
15	**Cash Expenditures for Nuclear Waste & Decommissioning**		463.9	0.0	463.9
16	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
17	**Pension Plan Contributions**		151.7	0.0	151.7
18	**OPEB Payments**		103.8	0.0	103.8
19	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
20	**Deductible SR&ED Qualifying Expenditures**		33.1	0.0	33.1
21	**Other**		6.3	0.0	6.3
22	**Total Deductions**		1,619.2	(27.4)	1,591.7
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		59.0	(34.9)	24.1
24	**Tax Loss Carry-Over / (Applied)**	7	(59.0)	34.9	(24.1)
25	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 23 + line 24)		0.0	0.0	0.0
26	**Regulatory Income Taxes - Federal** (line 24 x line 30)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Provincial** (line 24 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.1)	0.0	(16.1)
29	**Total Regulatory Income Taxes** (line 26 + line 27 + line 28)		(16.1)	0.0	(16.1)
	Income Tax Rate:				
30	**Federal Tax**		15.00%	0.00%	15.00%
31	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
32	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 20a.

Table 20a
Notes to Table 20
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities
Year Ending December 31, 2025

Notes:
1 As per Ex. F4-2-1, Table 3a, col. (a) - (e) updated on March 12, 2021.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	PAO App. A, Table 4, line 12 and line 12a	519.9	(49.1)	470.8
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 4, line 20	(46.5)	0.0	(46.5)
3a		line 1a - line 2a	566.4	(49.1)	517.3
			0.0		
4a	Additions for Regulatory Tax Purposes	line 13	1,236.7	(13.2)	1,223.5
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	PAO App. D Table 1, Lines 15-17	108.8	0.0	108.8
6a	Deductions for Regulatory Tax Purposes	line 22	1,619.2	(27.4)	1,591.7
7a		line 3a + line 4a - line 5a - line 6a	75.2	(34.9)	40.2
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	8.9	(5.2)	3.6
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	5.9	(3.5)	2.4
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.1)	0.0	(16.1)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(1.3)	(8.7)	(10.1)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(8.9)	5.2	(3.6)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(5.9)	3.5	(2.4)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(14.8)	8.7	(6.0)
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(16.1)	0.0	(16.1)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.1)	0.0	(16.1)
19a	After Tax Return on Equity	line 1a	519.9	(49.1)	470.8
20a	Less: Bruce Lease Net Revenues	line 2a	(46.5)	0.0	(46.5)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	108.8	0.0	108.8
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(16.1)	0.0	(16.1)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	441.5	(49.1)	392.3

2a Amounts from Ex. F4-2-1, Table 3c, updated on March 12, 2021.
3 Adjustment to After Tax ROE for Prescribed Nuclear Facilities per PAO App. A, Table 4, col. (c), lines 12 and 12a.
4 OEB Approved is per PAO App. A, Table 4, col. (c), line 17.
5 Reflects the impact of adjusted fuel expense per PAO App. A, Table 4a, Note 6, line (g) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year.
6 Adjusted to reflect changes to Capital Cost Allowance resulting from adjustments to capital in-service additions included in the OEB approved settlement proposal (Decision and Order, Schedule A, P. 21) and the OEB's disallowance of D2O Storage Project costs (OEB Decision and Order, P.35).

7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR term, with any remaining tax losses carried forward to future test periods. See PAO App. A, Table 22, col. (d), line 3 for loss applied.

Table 21
2026 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	468.7	(52.5)	416.2
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	568.6	(16.2)	552.4
3	**Nuclear Waste Management Expenses**		47.1	0.0	47.1
4	**Receipts from Nuclear Segregated Funds**		529.3	0.0	529.3
5	**Pension and OPEB Accrual**		183.5	0.0	183.5
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		21.1	0.0	21.1
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Act**		108.8	0.0	108.8
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
9	**Reversal of Niagara Tunnel Disallowance**		0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.1	0.0	16.1
12	**Other**	5	(69.3)	(0.7)	(70.0)
13	**Total Additions**		1,405.3	(16.9)	1,388.3
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	828.5	(27.5)	801.0
15	**Cash Expenditures for Nuclear Waste & Decommissioning**		638.4	0.0	638.4
16	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
17	**Pension Plan Contributions**		123.0	0.0	123.0
18	**OPEB Payments**		104.2	0.0	104.2
19	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
20	**Deductible SR&ED Qualifying Expenditures**		32.3	0.0	32.3
21	**Other**		6.9	0.0	6.9
22	**Total Deductions**		1,733.2	(27.5)	1,705.7
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		140.7	(41.9)	98.8
24	**Tax Loss Carry-Over / (Applied)**	7	(140.7)	41.9	(98.8)
25	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 23 + line 24)		0.0	0.0	0.0
26	**Regulatory Income Taxes - Federal** (line 24 x line 30)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Provincial** (line 24 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(15.9)	0.0	(15.9)
29	**Total Regulatory Income Taxes** (line 26 + line 27 + line 28)		(15.9)	0.0	(15.9)
	Income Tax Rate:				
30	**Federal Tax**		15.00%	0.00%	15.00%
31	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
32	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 21a.

Table 21a
Notes to Table 21
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities
Year Ending December 31, 2026

Notes:
1 As per Ex. F4-2-1, Table 3a, col. (a) - (e) updated on March 12, 2021.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	PAO App. A, Table 5, line 12 and line 12a	555.1	(52.5)	502.6
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 5, line 20	(38.3)	0.0	(38.3)
3a		line 1a - line 2a	593.4	(52.5)	540.9
4a	Additions for Regulatory Tax Purposes	line 13	1,405.3	(16.9)	1,388.3
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	PAO App. D Table 1, Lines 15-17	108.8	0.0	108.8
6a	Deductions for Regulatory Tax Purposes	line 22	1,733.2	(27.5)	1,705.7
7a		line 3a + line 4a - line 5a - line 6a	156.6	(41.9)	114.7
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	21.1	(6.3)	14.8
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	14.1	(4.2)	9.9
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(15.9)	0.0	(15.9)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	19.3	(10.5)	8.8
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(21.1)	6.3	(14.8)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(14.1)	4.2	(9.9)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(35.2)	10.5	(24.7)
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 28	(15.9)	0.0	(15.9)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(15.9)	0.0	(15.9)
19a	After Tax Return on Equity	line 1a	555.1	(52.5)	502.6
20a	Less: Bruce Lease Net Revenues	line 2a	(38.3)	0.0	(38.3)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	108.8	0.0	108.8
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(15.9)	0.0	(15.9)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	468.7	(52.5)	416.2

2a Amounts from Ex. F4-2-1, Table 3c, updated on March 12, 2021.
3 Adjustment to After Tax ROE for Prescribed Nuclear Facilities per PAO App. A, Table 5, col. (c), lines 12 and 12a.
4 OEB Approved is per PAO App. A, Table 5, col. (c), line 17.
5 Reflects the impact of adjusted fuel expense per PAO App. A, Table 5a, Note 6, line (g) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year.
6 Adjusted to reflect changes to Capital Cost Allowance resulting from adjustments to capital in-service additions included in the OEB approved settlement proposal (Decision and Order, Schedule A, P. 21) and the OEB's disallowance of D2O Storage Project costs (OEB Decision and Order, P.35).
7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR term, with any remaining tax losses carried forward to future test periods. See PAO App. A, Table 22, col. (e), line 3 for loss applied.

Table 22
2022 - 2026 Summary of Nuclear Regulatory Tax Losses ($M)

Line No.	Particulars	Note	2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**	1	(321.1)	(464.1)	(568.4)	(496.2)	(472.1)
2	**Income/(Loss) for the Year**	2	(143.0)	(104.3)	0.0	0.0	0.0
3	**Tax Loss Applied**	2	0.0	0.0	72.1	24.1	98.8
4	**Loss Carried Forward** (line 1 + line 2 + line 3)		(464.1)	(568.4)	(496.2)	(472.1)	(373.4)

Notes:
1 2022: Loss Carried Forward per EB-2016-0152 PAO App. A, Table 22, line 4, col. (e).
2 PAO App. A, Table 17, line 23, col. (c) for 2022; Table 18, line 23, col. (c) for 2023; Table 19, line 23, col. (c) for 2024; Table 20, line 23, col. (c) for 2025; Table 21, line 23, col. (c) for 2026.

Numbers may not add due to rounding.

Table 1
Payment Amounts - Nuclear
January 1, 2022 to December 31, 2026

Line No.	Description	Note	2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)
	PAYMENT AMOUNT:						
1	**Revenue Requirement Net of Stretch Factor ($M)**	1	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
2	**Forecast Production (TWh)**	2	33.6	31.2	34.0	31.1	21.9
3	**Smoothed Nuclear Payment Amount ($/MWh)**	3	102.64	106.30	103.48	102.85	111.33
4	**Forecast Nuclear Revenue Received** (line 2 x line 3)		3,448.7	3,319.5	3,518.3	3,197.6	2,439.5
5	**Nuclear Revenue Requirement Deferred** (line 1 - line 4)		66.7	110.5	0.0	0.0	0.0

Notes:
1 PAO App. A, Tables 1 to 5, line 26, col. (c).
2 Per OEB approved settlement proposal (Decision and Order, Schedule A, P. 25)
3 PAO App. B, Table 3, line 4.

Numbers may not add due to rounding.

Table 2A
Annualized Residential Consumer Impact
January 1, 2022 to December 31, 2026

Line No.	Description	Note	2022 Amount	2023 Amount	2024 Amount	2025 Amount	2026 Amount	Average
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption (kWh/Month)**	1	737	737	737	737	737	737
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)		363	350	365	349	299	345
3	**Typical Bill ($/Month)**	1	115.11	115.11	115.11	115.11	115.11	115.11
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)		1.04	0.26	(0.05)	0.08	(0.36)	**0.19**
5	**Typical Bill Impact (%)** (line 4 / line 3)		0.90%	0.23%	-0.04%	0.07%	-0.31%	**0.17%**
6	Prior Year OPG Weighted Average Total Payments ($/MWh)	2	71.76	74.63	75.38	75.23	75.44	74.49
7	Current Year OPG Weighted Average Total Payments ($/MWh)	2	74.63	75.38	75.23	75.44	74.25	74.98
8	Change in OPG Weighted Average Total Payments ($/MWh) (line 7 - line 6)		2.87	0.75	(0.15)	0.22	(1.20)	0.50
9	Total OPG Regulated Production (TWh)	3	66.6	64.2	67.0	64.1	54.9	63.3
10	Forecast of 2022 Provincial Demand (TWh)	4	135.2	135.2	135.2	135.2	135.2	135.2
11	OPG Proportion of Consumer Usage (line 9 / line 10)		49.2%	47.5%	49.5%	47.4%	40.6%	46.9%

Notes:

1 Typical monthly consumption (700 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility, accessed December 1, 2020
Typical Consumption includes line losses (Assumed loss factor of 1.0525)

2 PAO App. B, Table 3, line 9.

3 PAO App. B, Table 3, line 3 and line 6.

4 Based on forecast demand for 2022 (135.2 TWh) from Table 3-1 of IESO Reliability Outlook Update from July 2021 to December 2022, released June 2021.

Numbers may not add due to rounding.

Table 2B

Annualized Bill Impact for Typical Alectra (PowerStream) Consumers 2022-2026

Line No.	Description	Note	2022 Medium/Large Business	2022 Large Industrial	2023 Medium/Large Business	2023 Large Industrial	2024 Medium/Large Business	2024 Large Industrial	2025 Medium/Large Business	2025 Large Industrial	2026 Medium/Large Business	2026 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600
2	**Total Forecast Production (TWh)**	2	66.6	66.6	64.2	64.2	67.0	67.0	64.1	64.1	54.9	54.9
3	**OPG Portion of Consumer Usage**	3	49.2%	49.2%	47.5%	47.5%	49.5%	49.5%	47.4%	47.4%	40.6%	40.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		40,848	1,398,794	39,392	1,348,948	41,093	1,407,195	39,307	1,346,035	33,676	1,153,205
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	13,443	420,075	13,443	420,075	13,443	420,075	13,443	420,075	13,443	420,075
	EB-2016-0152/EB-2018-0243/EB-2020-0210 to EB-2020-0290:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	2.87	2.87	0.75	0.75	(0.15)	(0.15)	0.22	0.22	(1.20)	(1.20)
7	**Percentage Increase in Consumer Bills**		0.87%	0.96%	0.22%	0.24%	-0.05%	-0.05%	0.06%	0.07%	-0.30%	-0.33%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		117.25	4,015.10	29.40	1,006.73	(6.18)	(211.49)	8.51	291.48	(40.29)	(1,379.53)

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Alectra EB-2020-0002 proceeding, Excel File: dec_rate order_Alectra_RGM PRZ_20201217
GS > 50 customer, consumption 80,000 kWh, loss factor 3.69%
Large User customer, consumption 2,800,000 kWh, loss factor 1.45%
2 Per PAO App. B, Table 3, line 3 and line 6.
3 Per PAO App. B, Table 2A, line 11.
4 Per PAO App. B, Table 2A, line 8.

Numbers may not add due to rounding.

Table 2C
Annualized Bill Impact for Typical Hydro One Networks Consumers 2022-2026

Line No.	Description	Note	2022 Medium/Large Business	2022 Large Industrial	2023 Medium/Large Business	2023 Large Industrial	2024 Medium/Large Business	2024 Large Industrial	2025 Medium/Large Business	2025 Large Industrial	2026 Medium/Large Business	2026 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471
2	**Total Forecast Production (TWh)**	2	66.6	66.6	64.2	64.2	67.0	67.0	64.1	64.1	54.9	54.9
3	**OPG Portion of Consumer Usage**	3	49.2%	49.2%	47.5%	47.5%	49.5%	49.5%	47.4%	47.4%	40.6%	40.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		18,863	815,202	18,191	786,152	18,976	820,098	18,152	784,455	15,551	672,076
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489
	EB-2016-0152/EB-2018-0243/EB-2020-0210 to EB-2020-0290:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	2.87	2.87	0.75	0.75	(0.15)	(0.15)	0.22	0.22	(1.20)	(1.20)
7	**Percentage Increase in Consumer Bills**		0.64%	0.87%	0.16%	0.22%	-0.03%	-0.05%	0.05%	0.06%	-0.22%	-0.30%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		54.14	2,339.96	13.58	586.71	(2.85)	(123.25)	3.93	169.87	(18.60)	(803.98)

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2019-0043, Excel file: Exhibit 4.0 - 2020 Bill Impact
Medium/Large Business: GSd customer, consumption 35,000 kWh, loss factor 6.1%
Large Industrial: ST customer, consumption 1,601,036 kWh, loss factor 3.4%
2 Per PAO App. B, Table 3, line 3 and line 6.
3 Per PAO App. B, Table 2A, line 11.
4 Per PAO App. B, Table 2A, line 8.

Numbers may not add due to rounding.

Table 2D
Annualized Bill Impact for Typical Toronto Hydro Consumers 2022-2026

Line No.	Description	Note	2022 Medium/Large Business	2022 Large Industrial	2023 Medium/Large Business	2023 Large Industrial	2024 Medium/Large Business	2024 Large Industrial	2025 Medium/Large Business	2025 Large Industrial	2026 Medium/Large Business	2026 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	81,331	4,170,520	81,331	4,170,520	81,331	4,170,520	81,331	4,170,520	81,331	4,170,520
2	**Total Forecast Production (TWh)**	2	66.6	66.6	64.2	64.2	67.0	67.0	64.1	64.1	54.9	54.9
3	**OPG Portion of Consumer Usage**	3	49.2%	49.2%	47.5%	47.5%	49.5%	49.5%	47.4%	47.4%	40.6%	40.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		40,050	2,053,686	38,623	1,980,502	40,290	2,066,020	38,539	1,976,226	33,018	1,693,116
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	13,786	705,268	13,786	705,268	13,786	705,268	13,786	705,268	13,786	705,268
	EB-2016-0152/EB-2018-0243/EB-2020-0210 to EB-2020-0290:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	2.87	2.87	0.75	0.75	(0.15)	(0.15)	0.22	0.22	(1.20)	(1.20)
7	**Percentage Increase in Consumer Bills**		0.83%	0.84%	0.21%	0.21%	-0.04%	-0.04%	0.06%	0.06%	-0.29%	-0.29%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		114.96	5,894.90	28.82	1,478.06	(6.06)	(310.51)	8.35	427.95	(39.50)	(2,025.41)

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2020-0057, excel file THESL_T05_S_01_OEB_Appendix_2-W_Bill Impacts - Updated_20201202
Medium/Large Business: GS 50-999 customer, consumption 79,000 kWh, loss factor 2.95%
Large Industrial : Large Use customer, consumption 4,100,000 kWh, loss factor 1.72%
2 Per PAO App. B, Table 3, line 3 and line 6.
3 Per PAO App. B, Table 2A, line 11.
4 Per PAO App. B, Table 2A, line 8.

Numbers may not add due to rounding.

Table 3
Computation of Percentage Change in Payment Amounts
EB-2016-0152/EB-2018-0243/EB-2020-0210 to EB-2020-0290

Line No.	Description	Note	2021	2022	2023	2024	2025	2026
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	1	43.88	43.88	43.88	43.88	43.88	43.88
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	2	2.05	1.03	1.03	1.03	0.69	0.69
3	**Hydroelectric Production Forecast (HPF) TWh**	3	33.0	33.0	33.0	33.0	33.0	33.0
4	**Nuclear Payment Amount (NPA) ($/MWh)**	4	89.70	102.64	106.30	103.48	102.85	111.33
5	**Nuclear Payment Rider (NPR) ($/MWh)**	5	6.13	1.16	1.25	1.15	5.34	7.58
6	**Nuclear Production Forecast (NPF) TWh**	6	35.4	33.6	31.2	34.0	31.1	21.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		22.15	22.24	23.07	22.11	22.94	26.78
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.61	52.39	52.31	53.11	52.50	47.47
9	**Weighted Average Payment Amount ($/MWh)** ((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		71.76	74.63	75.38	75.23	75.44	74.25
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			4.0%	1.0%	-0.2%	0.3%	-1.6%

Notes
1 Col. (a) is per EB-2020-0210 Payment Amounts Order.
Col. (b) to (f) are set equal to the 2021 HPA approved in EB-2020-0210, per EB-2020-0290 Payment Amounts Order, P. 3.
2 Col. (a) is the EB-2018-0243 approved hydroelectric rider in effect until December 31, 2021.
Col. (b) to (f) are EB-2020-0290 approved hydroelectric riders per PAO App. C, Table 1.
3 Regulated Hydroelectric production is the 2014 and 2015 average OEB-approved hydroelectric production per EB-2013-0321 Decision and Order P. 9, and EB-2016-0152 PAO, App. I, Table 2, line 3.
4 Col. (a) is per EB-2016-0152 Payment Amounts Order, P. 10.
Col. (b) to (f) as calculated in OPG's revised smoothing proposal outlined in PAO, App. H.
5 Col. (a) is the EB-2018-0243 approved nuclear rider in effect until December 31, 2021.
Col. (b) to (f) are EB-2020-0290 approved nuclear riders per PAO App. D, Table 1.
6 Col. (a) is per EB-2016-0152 Payment Amounts Order, P. 9.
Col. (b) to (f) is per EB-2020-0290 Payment Amounts Order, P. 3.

Numbers may not add due to rounding.

Table 1

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

Line No.	Account	Note	Audited Year End Balance 2019	EB-2016-0152 OEB-Approved Amortization (2020)	EB-2018-0243 OEB-Approved Amortization (2020-2021)	(a)-(b)-(c) 2019 Balance Less Approved Amortization	Amounts Deferred to Future Applications	(d)-(e) Amounts Recoverable in Current Application	Recovery Period (months)	Amortization Jan - Dec 2022	Amortization Jan - Dec 2023	Amortization Jan - Dec 2024	Amortization Jan - Dec 2025	Amortization Jan - Dec 2026	(h)+(i)+(j)+(k)+(l) Amortization	(d)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3		Note 11		Note 12							
1	**Hydroelectric Water Conditions Variance**		(215.8)	(6.1)	(100.6)	(109.1)	0.0	(109.1)	36	(36.4)	(36.4)	(36.4)	0.0	0.0	(109.1)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(62.1)	(4.6)	(24.1)	(33.4)	0.0	(33.4)	36	(11.1)	(11.1)	(11.1)	0.0	0.0	(33.4)	0.0
3	**Hydroelectric Incentive Mechanism Variance**		(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		447.7	28.9	210.5	208.3	40.0	168.3	36	56.1	56.1	56.1	0.0	0.0	168.3	40.0
5	**Income and Other Taxes Variance - Hydroelectric**		(2.6)	(0.0)	0.0	(2.6)	0.0	(2.6)	36	(0.9)	(0.9)	(0.9)	0.0	0.0	(2.6)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**		26.2	1.1	0.0	25.0	25.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	25.0
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account**		8.2	0.0	4.4	3.8	0.0	3.8	36	1.3	1.3	1.3	0.0	0.0	3.8	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric - Future**	9	6.3	0.7	2.4	3.2	0.0	3.2	36	1.1	1.1	1.1	0.0	0.0	3.2	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**		15.3	4.1	11.2	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**	8	41.3	0.0	0.0	41.3	0.0	41.3	60	8.3	8.3	8.3	8.3	8.3	41.3	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non - RPP - EB-2018-0243 Approved**	9	34.9	0.0	14.0	21.0	0.0	21.0	36	7.0	7.0	7.0	0.0	0.0	21.0	0.0
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions**		44.1	0.0	0.0	44.1	0.0	44.1	60	8.8	8.8	8.8	8.8	8.8	44.1	0.0
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(59.9)	1.5	(22.8)	(38.6)	0.0	(38.6)	36	(12.9)	(12.9)	(12.9)	0.0	0.0	(38.6)	0.0
14	**Pension and OPEB Forecast Accrual versus Actual Cash Differential - Carrying Charges - Hydroelectric**		(0.1)	0.0	0.0	(0.1)	0.0	(0.1)	36	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.1)	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		17.3	4.7	9.2	3.4	0.0	3.4	36	1.1	1.1	1.1	0.0	0.0	3.4	0.0
16	**Total**		300.8	30.4	104.1	166.3	65.0	101.3		22.4	22.4	22.4	17.1	17.1	101.3	65.0
17	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - RPP - EB-2018-0243 Approved**	5, 8				13.8	0.0	13.8	60	2.8	2.8	2.8	2.8	2.8	13.8	0.0
18	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non RPP - EB-2018-0243 Approved**	6,9				7.0	0.0	7.0	36	2.3	2.3	2.3			7.0	0.0
19	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions**	7				14.7	0.0	14.7	60	2.9	2.9	2.9	2.9	2.9	14.7	0.0
20	**Settlement Adjustment: COVID-19 Impacts**	10						10.9	36	3.6	3.6	3.6	0.0	0.0	10.9	0.0
21	**Total Recoverable Amount**					201.8	65.0	147.7		34.0	34.0	34.0	22.8	22.8	147.7	65.0
22	**Forecast Production (TWh)**	4								33.0	33.0	33.0	33.0	33.0		
23	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 21 / line 22)									1.03	1.03	1.03	0.69	0.69		

Notes:

1 From Ex. H1-1-1 Table 1, col. (c).
2 From EB-2016-0152 PAO, App. D, Table 1, col. (g).
3 From EB-2018-0243, Settlement Proposal, Att. A, Table 1, cols. (j) and (k), which forms the basis of the payment amounts approved in the Decision and Payment Amounts Order dated February 21, 2019.
4 From PAO, App. B, Table 3, line 3.
5 Calculated as: line 10 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
6 Calculated as: line 11 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
7 Calculated as: line 12 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
8 The December 31, 2017 balance of the Pension & OPEB Cash Vs Accrual Differential Deferral Account related to Hydroelectric - RPP (line 10) and the associated income tax impacts (line 17) were accepted as part of the EB-2018-0243 Settlement Proposal (p. 10). The recovery was deferred to this application.
9 Amortized over the period to December 31, 2024 as per EB-2018-0243 Settlement Proposal, Attachment A, Table 1, which forms the basis of the payment amounts approved in the Decision and Payment Amounts Order dated February 21, 2019.
10 Represents recovery from customers of the regulated hydroelectric facilities' portion of the COVID-19 related amounts per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 19). Amount in col. (f) is per Ex. L-A2-02-CCC-013, Att. 1: line 7, col. (b), plus line 7, col. (e), less line 10, col. (b), less line 10, col. (e).
11 From Ex. H1-2-1, Table 1, col. (e), other than line 4 which represents a settlement adjustment to defer a portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account to a subsequent proceeding (Decision and Order, Schedule A, P. 28)
12 From Ex. H1-2-1, Table 1, col. (g) for lines 1-19.

Numbers may not add due to rounding.

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

Line No.	Account	Note	Audited Year End Balance 2019	EB-2016-0152 OEB-Approved Amortization (2020)	EB-2018-0243 OEB-Approved Amortization (2020-2021)	(a)-(b)-(c) 2019 Balance Less Approved Amortization	OEB Adjustments	Amounts Deferred to Future Applications	(d)+(d1)-(e) Amounts Recoverable in Current Application	Recovery Period (months)	Amortization Jan - Dec 2022	Amortization Jan - Dec 2023	Amortization Jan - Dec 2024	Amortization Jan - Dec 2025	Amortization Jan - Dec 2026	(h)+(i)+(j)+(k)+(l) Amortization	(d)+(d1)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(d1)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3												
1	**Nuclear Liability Deferral**		12.4	0.0	12.4	0.0		0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral**	12	(92.3)	0.0	(92.3)	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Nuclear Development Variance**		5.2	0.6	0.2	4.4		0.7	3.7	36	1.2	1.2	1.2	0.0	0.0	3.7	0.7
4	**Ancillary Services Net Revenue Variance - Nuclear**		(1.1)	0.3	2.2	(3.6)		0.0	(3.6)	36	(1.2)	(1.2)	(1.2)	0.0	0.0	(3.6)	0.0
5	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Project**	15	38.3	(17.4)	0.0	55.7	10.3	65.9	0.0		0.0	0.0	0.0	0.0	0.0	0.0	65.9
6	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		(102.9)	(6.8)	0.0	(96.1)		0.0	(96.1)	36	(32.0)	(32.0)	(32.0)	0.0	0.0	(96.1)	0.0
7	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP**		(19.2)	0.0	0.0	(19.2)		0.0	(19.2)	36	(6.4)	(6.4)	(6.4)	0.0	0.0	(19.2)	0.0
8	**Capacity Refurbishment Variance - Nuclear - D2O Project**	14	58.0	0.0	0.0	58.0	(57.9)	0.0	0.1	36	0.0	0.0	0.0	0.0	0.0	0.1	0.0
9	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	13	(26.9)	(24.0)	(0.7)	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved**	10	168.8	7.2	56.4	105.3		0.0	105.3	60	21.1	21.1	21.1	21.1	21.1	105.3	0.0
11	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post-2017 Additions**		23.1	0.0	0.0	23.1		0.0	23.1	36	7.7	7.7	7.7	0.0	0.0	23.1	0.0
12	**Income and Other Taxes Variance - Nuclear**		(21.1)	(1.5)	(5.1)	(14.5)		0.0	(14.5)	36	(4.8)	(4.8)	(4.8)	0.0	0.0	(14.5)	0.0
13	**Pension and OPEB Cost Variance - Nuclear - Future**	9	136.9	15.0	57.5	64.4		0.0	64.4	36	21.5	21.5	21.5	0.0	0.0	64.4	0.0
14	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**		331.5	79.2	252.4	0.0		0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**	8	266.0	0.0	0.0	266.0		0.0	266.0	60	53.2	53.2	53.2	53.2	53.2	266.0	0.0
16	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non - RPP - EB-2018-0243 Approved**	9	220.4	0.0	88.2	132.2		0.0	132.2	36	44.1	44.1	44.1	0.0	0.0	132.2	0.0
17	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions**		278.2	0.0	0.0	278.2		0.0	278.2	60	55.6	55.6	55.6	55.6	55.6	278.2	0.0
18	**Pension & OPEB Cash Payment Variance - Nuclear**		(288.6)	8.2	(122.6)	(174.2)		0.0	(174.2)	36	(58.1)	(58.1)	(58.1)	0.0	0.0	(174.2)	0.0
19	**Pension and OPEB Forecast Accrual versus Actual Cash Differential - Carrying Charges - Nuclear**		(0.6)	0.0	0.0	(0.6)		0.0	(0.6)	36	(0.2)	(0.2)	(0.2)	0.0	0.0	(0.6)	0.0
20	**Nuclear Deferral and Variance Over/Under Recovery Variance**	13	19.8	15.4	27.3	(25.1)		0.0	(25.1)	36	(8.4)	(8.4)	(8.4)	0.0	0.0	(25.1)	0.0
21	**Fitness for Duty Deferral**		0.5	0.0	0.0	0.5		0.5	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.5
22	**SR&ED ITC Variance**		(15.1)	0.0	(3.0)	(12.1)		0.0	(12.1)	36	(4.0)	(4.0)	(4.0)	0.0	0.0	(12.1)	0.0
23	**Rate Smoothing Deferral**		104.3	0.0	0.0	104.3		104.3	0.0		0.0	0.0	0.0	0.0	0.0	0.0	104.3
24	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral**		(245.8)	0.0	0.0	(245.8)		0.0	(245.8)	36	(81.9)	(81.9)	(81.9)	0.0	0.0	(245.8)	0.0
25	**Total**		849.8	76.3	272.7	500.8	(47.7)	171.4	281.8		7.3	7.3	7.3	129.9	129.9	281.8	171.4
26	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - RPP - EB-2018-0243 Approved**	5, 8				88.7		0.0	88.7	60	17.7	17.7	17.7	17.7	17.7	88.7	0.0
27	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non RPP - EB-2018-0243 Approved**	6, 9				44.1		0.0	44.1	36	14.7	14.7	14.7	0.0	0.0	44.1	0.0
28	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions**	7				92.7		0.0	92.7	60	18.5	18.5	18.5	18.5	18.5	92.7	0.0
29	**Settlement Adjustment: COVID-19 Impacts**	11							(57.5)	36	(19.2)	(19.2)	(19.2)	0.0	0.0	(57.5)	0.0
30	**Total Recoverable Amount**					726.3	(47.7)	171.4	449.7		39.1	39.1	39.1	166.2	166.2	449.7	171.4
31	**Forecast Production (TWh)**	4									33.6	31.2	34.0	31.1	21.9		
32	**Nuclear Payment Rider ($/MWh)** (line 30 / line 31)										1.16	1.25	1.15	5.34	7.58		

Notes:
1 From Ex. H1-1-1 Table 1, col. (c).
2 From EB-2016-0152 PAO, App. E, Table 1, col. (g).
3 From EB-2018-0243, Settlement Proposal, Attatchment A, Table 2, cols. (j) and (k), which forms the basis of the payment amounts approved in the Decision and Payment Amounts Order dated February 21, 2019.
4 From PAO, App. B, Table 3, line 6.
5 Calculated as: line 15 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
6 Calculated as: line 16 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
7 Calculated as: line 17 * tax rate / (1 - tax rate). Tax rate from PAO App. A, Table 17, line 32, col. (c).
8 The December 31, 2017 balance of the Pension & OPEB Cash Vs Accrual Differential Deferral Account related to Nuclear - RPP (line 15) and the associated income tax impacts (line 26) were accepted as part of the EB-2018-0243 Settlement Proposal (p. 10). The recovery was deferred to this application.
9 Amortized over the period to December 31, 2024 as per EB-2018-0243 Settlement Proposal, Attachment A, Table 2, which forms the basis of the payment amounts approved in the Decision and Payment Amounts Order dated February 21, 2019.
10 Amortized over the period to December 31, 2026 as per EB-2018-0243 Settlement Proposal, Att. A, Table 2, which forms the basis of the payment amounts approved in the Decision and Payment Amounts Order dated February 21, 2019.
11 Represents credit to customers of the Nuclear facilities' portion of the COVID-19 related amounts per the OEB approved settlement proposal (Decision and Order, Schedule A, P. 19). Amount in col. (f) is per Ex. L-A2-02-CCC-013, Att. 1: line 7, col. (a), plus line 7, col. (d), less line 10, col. (a), less line 10, col. (d).
12 Account is terminated effective January 1, 2022.
13 As set out in PAO, App. E, the Derivative Sub-Account is terminated effective January 1, 2022; its remaining balance and approved amortization shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account beginning in 2022 and are reflected on this basis at lines 9 and 20, cols. (d)-(n).
14 Adjustment in col. (d1) reflects the OEB's findings regarding the D2O Storage Project, comprised of disallowances of $94M in costs incurred as of October 2014 and the carrying costs incurred from May 2017 to March 2020, and a March 2020 in-service date for the full amount of the approved costs (Decision and Order, PP. 35,52).
The adjusted account entries comprising the Capacity Refurbishment Variance Account - D2O Project balance recoverable in this application are calculated in PAO App. D, Table 2.
15 The income tax impact of the Capital Cost Allowance related to the D2O Storage Project is included within the overall Darlington Refurbishment Program variances in the Capacity Refurbishment Variance Account - DRP - Excluding D2O Project balance and the Capacity Refurbishment Variance Account - DRP - Accelerated Investment Incentive CCA - DRP balance (Ex. H1-1-1, Table 16, Note 3). Adjustment in col. (d1) reflects the reduction in past Capital Cost Allowance amounts arising from the disallowance of expenditures per the OEB's findings regarding the D2O Storage Project.

Numbers may not add due to rounding.

Table 2
Capacity Refurbishment Variance Account - Nuclear - D2O Storage Project Component - Adjusted for OEB's Findings
Summary of Account Transactions - 2016, 2017, 2018 and 2019 ($M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	(a)+(d)+(e)+(f) Total 2016-2019
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Capital Addition to Variance Account:								
1	**Forecast Cost of Capital Amount**	1	0.7	0.3	0.5		0.9	0.8	
2	**Actual Net Plant Rate Base Amount**	2	13.9	13.5	13.5		13.2	12.8	
3	**Weighted Average Cost of Capital**	3	6.85%	6.85%	6.65%		6.50%	6.46%	
4	**Actual Cost of Capital Amount**		1.0	0.4	0.5	0.9	0.9	0.8	
5	**Cost of Capital Variance** (line 4 - line 1)		0.3	0.1	0.0	0.1	0.0	0.0	
6	**Forecast Depreciation**	4	0.6	0.2	0.2	0.5	0.4	0.4	
7	**Actual Depreciation**	5	0.4	0.2	0.2	0.4	0.4	0.4	
8	**Depreciation Variance** (line 7 - line 6)		(0.2)	(0.1)	0.0	(0.1)	0.0	0.0	
	Income Tax Impact:								
9	**Net (Decrease) Increase in Regulatory Taxable Income**		(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	
10	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	
11	**Income Tax Impact** (line 9 x line 10 / (1 - line 10))		(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	
12	**Total Capital Additon to Variance Account - Nuclear** (line 5 + 8 + 11)		0.1	0.0	0.0	0.0	0.0	0.0	0.1

Notes:
1 From Ex. H1-1-1, Table 16, line 1.
2 Calculated as PAO App. A: Table 9a, Note 3, line 3f less Table 10a, Note 4, line 4e for corrsponding years.
3 From Ex. H1-1-1, Table 16, line 3.
4 From Ex. H1-1-1, Table 16, line 6.
5 Calculated as PAO App. A, Table 10a, Note 4: line 4b plus line 4c for corresponding years.

Appendix E: Clearance and Continuation of Existing Deferral and Variance Accounts

1.0 CLEARANCE OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

With respect to the deferral and variance accounts established by Ontario Regulation 53/05 ("O. Reg. 53/05") and the OEB's decisions and orders in EB-2007-0905, EB-2009-0174, EB-2010-0008, EB-2011-0090, EB-2012-0002, EB-2013-0321, EB-2014-0369, EB-2014-0370, EB-2015-0374, EB-2016-0152, EB-2018-0002 and EB-2018-0243, the OEB approves:

1) A disposition debit amount of $101.3M (App. C, Table 1, col. (m), line 16) for this proceeding from regulated hydroelectric deferral and variance accounts, reflecting OPG's approved recovery of the applicable audited December 31, 2019 balances in deferral and variance accounts (App. C, Table 1, col. (a)) less amortization amounts for 2020 and 2021 approved in EB-2016-0152 (App. C, Table 1, col. (b)) and EB-2018-0243 (App. C, Table 1, col. (c)), plus additional net amounts totaling $46.4M for the income tax impact associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the settlement adjustment related to OPG's COVID-19 impacts, for a grand total recoverable amount of $147.7M (App. C, Table 1, col. (m), line 21); and

2) A disposition debit amount of $281.8M (App. D, Table 1, col. (m), line 25) for this proceeding from nuclear deferral and variance accounts, reflecting OPG's approved recovery of the applicable audited December 31, 2019 balances in deferral and variance accounts (App. D, Table 1, col. (a), as adjusted by App. D, Table 1, col. (d1)) less amortization amounts for 2020 and 2021 approved in EB-2016-0152 (App. D, Table 1, col. (b)) and EB-2018-0243 (App. D, Table 1, col. (c)), plus additional net amounts totaling $168.0M for the income tax impact associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the settlement adjustment related to OPG's COVID-19 impacts, for a grand total recoverable amount of $449.7M (App. D, Table 1, col. (m), line 30).

The OEB approves recovery of the above approved balances in the regulated hydroelectric deferral and variance accounts, together with the above additional amounts, using payment riders of $1.03/MWh from January 1, 2022 to December 31, 2024 and $0.69/MWh from January 1, 2025 to December 31, 2026, as determined in App. C, Table 1, line 23.

The OEB approves recovery of the above approved balances in the nuclear deferral and variance accounts, together with the above additional amounts, using payment riders of $1.16/MWh for 2022, $1.25/MWh for 2023, $1.15/MWh for 2024, $5.34/MWh for 2025, and $7.58/MWh for 2026, as determined in App. D, Table 1, line 32.

OPG shall continue to record entries into the deferral and variance accounts established by O. Reg. 53/05 and the EB-2016-0152, EB-2018-0002, EB-2018-0243 and EB-2020-0248 decision and orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and the above proceedings until the effective date of this payment amounts order. The descriptions for continuing deferral and variance accounts provided below are effective as of the effective date of this Payment Amounts Order.

2.0 CONTINUING DEFERRAL AND VARIANCE ACCOUNTS

Unless otherwise stated in this Payment Amounts Order, as of the effective date of the payment amounts established in this proceeding, OPG shall continue to record entries in the deferral and variance accounts authorized by O. Reg. 53/05 and the applicable decisions and orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and such decisions and orders, as set out below.

All references to the “regulated hydroelectric facilities” shall mean the 54 OPG hydroelectric generation stations subject to OEB rate regulation, as specified in O. Reg. 53/05. These facilities consist of five generation stations in the Niagara Region (Sir Adam Beck I and Sir Adam Beck II generating stations, Sir Adam Beck Pump Generating Station and DeCew Falls I and DeCew Falls II generating stations) and the R.H. Saunders generating station, all of which have been subject to rate regulation by the OEB since 2008 (“previously regulated hydroelectric facilities”), and the 48 hydroelectric generation stations that became subject to OEB rate regulation effective July 1, 2014 (“newly regulated hydroelectric facilities”).

2.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05 and was approved by the OEB in EB-2007-0905 and all subsequent OPG applications. This account shall continue to record the financial impact of differences, including changes in gross revenue charge ("GRC") costs, between the actual production amount for the regulated hydroelectric facilities and the reference production values, arising from changes in actual water conditions.

For the previously regulated hydroelectric facilities, OPG will determine the hydroelectric production impact of changes in water conditions by entering the actual flow values into the same production forecast models used to calculate the OEB-approved production forecast, holding all other variables constant. OPG shall continue to use the average of the monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts as the reference values against which to measure production variances due to changes in water conditions arising for the corresponding months.

For the newly regulated hydroelectric facilities, 21 of 48 facilities listed in Ex. H1-1-1, Att. 3 use computer models to forecast production. The models convert forecast water availability to monthly energy production forecasts using historical median monthly flows. Similar to the previously regulated hydroelectric facilities, for these 21 facilities, OPG shall continue to compute deviations of actual monthly flows from historical median monthly flows in order to determine the production variance. In calculating deviations from forecast for January 1 to June 30 of each year, OPG shall use the corresponding monthly production forecasts for 2015 underpinning the EB-2013-0321 payment amounts. In calculating such deviations for July 1 to December 31 of each year, OPG shall use the average of the corresponding monthly production forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

The revenue impact of the production variance recorded in this account will continue to be determined by multiplying the deviation from forecast by the approved hydroelectric payment amount in effect. OPG shall also record in this account changes in GRC costs from those that underpin the payment amounts that were approved by the OEB, as a result of differences in energy production calculated as above. Amounts recorded in the account in respect of these costs shall be determined by multiplying the production deviation as described above by the applicable GRC rates.

OPG shall also record in this account any variances in amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal, as well as any variances in amounts payable to the Government of Quebec for water rentals, from those reflected in the payment amounts for regulated hydroelectric facilities that were approved by the OEB in EB-2013-0321.

2.2 Ancillary Services Net Revenue Variance Account

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. The account shall continue to be divided into the Ancillary Services Net Revenue Variance Account – Hydroelectric and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts.

Ancillary services for regulated hydroelectric operations include black start capability, operating reserve, regulation service, and reactive support/voltage control service. Ancillary services for nuclear operations include reactive support/voltage control service.

To determine additions in the Hydroelectric Sub-Account, OPG shall compare actual regulated hydroelectric ancillary services net revenue to the forecast amounts reflected in the hydroelectric revenue requirement approved by the OEB. Such monthly reference amount shall continue to be 1/12 of the average annual 2014 and 2015 forecast underpinning the revenue requirement approved by the OEB in EB-2013-0321, or $4.62M.[1]

To determine additions in the Nuclear Sub-Account, OPG shall compare actual nuclear ancillary services net revenue to the forecast amount reflected in the nuclear revenue requirement approved by the OEB. Such monthly reference amount shall be 1/12 of the corresponding annual amounts reflected in the revenue requirement approved by the OEB in

[1] EB-2016-0152 Payment Amounts Order, Appendix G, p. 5.

this proceeding. Such annual amounts are $5.8M for 2022, $6.3M for 2023, $6.1M for 2024, $6.5M for 2025 and $3.5M for 2026.[2] The resulting monthly reference amounts shall be $0.48M for 2022, $0.53M for 2023, $0.51M for 2024, $0.54M for 2025 and $0.29M for 2026.

2.3 Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 in conjunction with OPG's hydroelectric incentive mechanism ("HIM") and has been approved in all subsequent OPG applications. OPG shall continue to record in the variance account a credit to ratepayers equal to 50% of its total regulated HIM net revenues above the annual threshold of $54.5M. This threshold reflects the average of the 2014 annual threshold of $51M and the 2015 threshold of $58M approved in EB-2013-0321.

2.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. This account shall continue to record the financial impact of foregone production at the previously regulated hydroelectric facilities and the 21 newly regulated hydroelectric facilities listed Ex. H1-1-1, Att. 3 due to surplus baseload generation ("SBG") conditions.

Entries in the account shall continue to be calculated by multiplying the foregone production volume due to SBG conditions (in MWh), determined as per below, by the approved hydroelectric payment amount in effect. The amount recorded in the account shall be net of the avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates.

As detailed in EB-2013-0321, Ex. E1-2-1, Section 3.2 and set out in the EB-2016-0152 Payment Amounts Order,[3] OPG shall continue to calculate foregone production due to SBG by starting with the total volume of spill and subtracting the volume of spill due to:

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[2] Ex. G2-1-1, Table 1, line 8, as increased by 10% as part of the settled amount of other revenues (EB-2020-0290 Decision and Order, Schedule A, p. 27).
[3] EB-2016-0152 Payment Amounts Order, Appendix G, p. 6.

- water conveyance constraints (e.g., Sir Adam Beck Generating Stations tunnel capacity constraints);
- production capability constraints (e.g., unit outages; operating regulatory requirements etc.);
- market constraints (i.e., IESO dispatch constraints: market or transmission system); and
- contractual obligations (e.g., regulation service).

The remaining spill volume is identified as potential SBG spill. From this potential spill volume, OPG excludes spill that occurs when the Ontario market price is above the level of the GRC. The volume of spill remaining after this adjustment is the foregone production due to SBG that is used to record entries in this account.

OPG shall also record in this account any variances in amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal and in the amounts payable to the Government of Quebec for water rentals, as a result of foregone production due to SBG conditions.

2.5 Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account shall continue to record the financial impact on the revenue requirement approved by the OEB of the following, with the exception of the impact of any of the following as it relates to Scientific Research and Experimental Development investment tax credits (“SR&ED ITCs”) and the income taxes payable thereon for the nuclear facilities, which shall continue to be recorded in the SR&ED ITC Variance Account:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;

- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*;
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and
- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

The income tax provision and the underlying inputs reflected in the revenue requirement approved by the OEB shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account. Such reference amounts for the regulated hydroelectric facilities shall be those reflected in the average 2014 and 2015 income tax provision approved by the OEB in EB-2013-0321 and shown in the Payment Amounts Order Appendix A, Table 7 and Table 8 of that proceeding, as adjusted for the removal of the application of the nuclear facilities' tax loss to the regulated hydroelectric facilities in 2015. As in the EB-2016-0152 Payment Amounts Order, the resulting monthly reference amount for the regulated hydroelectric facilities shall be $6.52M, or 1/24 of the adjusted total income tax provision for 2014 and 2015 of $156.4M.[4]

The reference amount to be used in determining variances for the nuclear facilities shall be the corresponding annual income tax provision reflected in the nuclear revenue requirement approved by the OEB in this proceeding, as calculated in Appendix A, Tables 17-21, col. (c), line 29. The monthly reference amount for the nuclear facilities shall be ($1.38M) for 2022,

[4] As per EB-2016-0152 Payment Amounts Order, Appendix G, p. 8, calculated as the sum of: 2014 Income Taxes for Previously and Newly Regulated Hydroelectric Facilities of $47.4M and $21.4 respectively (EB-2013-0321 Payment Amounts Order, Appendix A, line 23 col. (c) of Tables 1 and 2 respectively) and 2015 Income Taxes of $53.2M and $34.4M for Previously and Newly Regulated Hydroelectric Facilities respectively (EB-2016-0152, Ex. I1-2-1 Table 2a, col (a) and (b), line 14).

($1.36M) for 2023, ($1.37M) for 2024, ($1.34M) for 2025 and ($1.33M) for 2026, being 1/12 of the annual amounts reflected in the approved revenue requirements for 2022-2026.

2.6 Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account ("CRVA") was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. Pursuant to Section 6(2)4 of O. Reg. 53/05, this account shall continue to record the financial impacts of variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in Section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB. The account shall continue to include assessment costs and pre-engineering costs and commitments as required by O. Reg. 53/05 s. 6(2)4. In 2015, O. Reg. 53/05 was amended to affirm that the scope of the account includes the capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Program ("DRP").

For the regulated hydroelectric facilities, the CRVA will record entries relative to the annual reference amount of $1.0M reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321 as escalated by the price cap index applied to adjust the hydroelectric payment amounts approved by the OEB for 2018 through 2021.[5] Additionally, OPG shall be entitled to recover amounts recorded in the CRVA effective January 1, 2022 in relation to the regulated hydroelectric facilities to the extent that total capital in-service additions for these facilities exceed the funding available for capital expenditures through the hydroelectric payment amounts established in this proceeding. The annual capital funding implicit in the hydroelectric payment amounts shall be $153.0M, as determined by escalating the average 2014 and 2015 OEB-approved depreciation of $143.3M, being the annual average of the depreciation expense for the regulated hydroelectric facilities reflected in the revenue requirement approved by the OEB for 2014 and 2015 in EB-2013-0321, by the price cap index applied to adjust the hydroelectric payment amounts approved by the OEB for 2018 through

[5] As per EB-2016-0152 Payment Amounts Order, Appendix G, p. 9, the annual reference amount prior to escalation at the price cap index was $0.9M.

2021.[6] In line with the approved hydroelectric payment amount in effect for 2022 through 2026 pursuant to Section 6(2)13 of O. Reg. 53/05, the annual capital funding implicit in the hydroelectric payment amounts for this period shall be equal to the 2021 value of $153.0M, and the annual reference amount shall be equal to the 2021 value of $1.0M. The resulting monthly funding amount shall be $12.75M, and the resulting monthly reference amount shall be $0.08M.

For the nuclear facilities, the account shall continue to record entries relative to the non-capital and capital reference amounts reflected in the annual revenue requirement approved by the OEB for this proceeding. The monthly reference amounts for the DRP non-capital component shall be 1/12 of $24.2M in 2022, $23.6M in 2023, $29.3M in 2024, $25.0M in 2025 and $8.4M in 2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[7] The monthly reference amounts for the non-DRP non-capital component shall be 1/12 of $52.3M in 2022, $23.6M in 2023, $19.4M in 2024, $0.4M in 2025 and $0.0M in 2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[8] The monthly reference amounts for the DRP capital component shall be 1/12 of $443.6M for 2022, $418.8M for 2023, $705.7M for 2024, $850.3M for 2025, and $951.2M for 2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[9] The monthly reference amounts for the non-DRP capital component shall be 1/12 of $12.7M for 2022, $12.1M for 2023, $11.6M for 2024, ($0.1M) for 2025, and ($0.4M) for 2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[10] The resulting monthly reference amounts for the above components shall be:

- For the DRP non-capital component: $2.0M for 2022, $2.0M for 2023, $2.4M for 2024, $2.1M for 2025, and $0.7M for 2026;
- For the non-DRP non-capital component: $4.4M for 2022, $2.0M for 2023, $1.6M for 2024, $0.0M for 2025, and $0.0M for 2026;

[6] This process is summarized at Ex. H1-1-1, Chart 1.
[7] Ex. F2-7-1, Table 1, line 1.
[8] Ex. L-H1-01-Staff-328, Chart 1, lines 4 and 9.
[9] Refer to Attachment 1.
[10] The reference amount for the non-DRP capital component is equal to the revenue requirement impact of forecast Pickering Extended Operations capital as presented at Ex. L-H1-01-Staff-328, Chart 3, updated for the settled capital structure (EB-2020-0290 Decision and Order, Schedule A, pp. 24-25) and the 2022 Return on Equity rate as specified by the OEB pursuant to the Cost of Capital Parameter Update Letter, October 28, 2021.

- For the DRP capital component: \$37.0M for 2022, \$34.9M for 2023, \$58.8M for 2024, \$70.9M for 2025, and \$79.3M for 2026 (as calculated in Attachment 1); and
- For the non-DRP capital component: \$1.1M for 2022, \$1.0M for 2023, \$1.0M for 2024, \$0.0M for 2025, and \$0.0M for 2026.

2.7 Pension and OPEB Cost Variance Account

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

In EB-2012-0002, the approved December 31, 2012 balance in the Pension and OPEB Cost Variance Account was split into the Historic Recovery and Future Recovery components. In EB-2013-0321, a third component was identified, which comprised additions recorded in the account subsequent to December 31, 2012 and up to November 1, 2014 (Post-2012 Additions). As at December 31, 2021, the Historic Recovery and Post-2021 Additions component will have been fully amortized. OPG shall continue to track the Future Recovery component separately until it is fully amortized by December 31, 2024, as previously approved by the OEB. [11]

As the revenue requirements approved by the OEB in this proceeding reflect pension and OPEB costs calculated on an accrual basis, OPG shall resume recording additions to the account for the nuclear facilities. The monthly reference amount for pension and OPEB costs shall be 1/12 of \$311.7M in 2022, \$294.1M in 2023, \$272.7M in 2024, \$228.2M in 2025, and \$183.5M in 2026.[12] The resulting monthly reference amount for pension and OPEB costs shall be \$26.0M for 2022, \$24.5M for 2023, \$22.7M for 2024, \$19.0M for 2025, and \$15.3M for

[11] EB-2016-0152 Payment Amounts Order, Appendix G, p. 11, as continued in EB-2018-0243 (Ex. M1, Attachment A, Table 1, line 8 and Table 2, line 10).
[12] Per Ex. F4-3-2, Chart 1.

2026. The monthly reference amount for the associated income tax PILs impacts shall be 1/12 of \$21.7M for 2022, \$13.7M for 2023, \$5.8M for 2024, \$(9.1)M for 2025, and \$(14.6)M for 2026.[13] The resulting monthly reference amount for the associated income tax PILs impacts shall be \$1.8M for 2022, \$1.1M for 2023, \$0.5M for 2024, \$(0.8)M for 2025, and \$(1.2)M for 2026.

For the regulated hydroelectric facilities, OPG shall continue to record only amortization in the account, as the hydroelectric revenue requirements approved for 2014 and 2015 by the OEB in EB-2013-0321 that underpin the approved hydroelectric payment amounts in this proceeding do not include pension and OPEB costs calculated on an accrual basis and instead reflect forecast registered pension plan ("RPP") contributions and OPEB plan payments (including the long-term disability benefit plan).

OPG shall not record any interest on the balance of this account as previously ordered by the OEB.

2.8 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

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

2.9 Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was originally approved in EB-2013-0321 and continued in all subsequent OPG applications. The account will continue to record the cost impact of a GRC reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources and Forestry, pertaining to production increases at OPG's Sir

[13] Income tax PILs impacts are determined by multiplying additions to and deductions from regulatory earnings before tax (Appendix A, Tables 17-21: line 5 less line 17 less line 18) by 25% / (1 - 25%).

Adam Beck plants due to the operation of the new Niagara tunnel. The impact, if any, shall be determined by applying the approved reduction to the forecast GRC costs included in the hydroelectric revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321, averaged as applicable, holding all other variables constant. The impact shall be calculated as of the later of November 1, 2014 and the effective date of the approved GRC reduction.

2.10 Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in all subsequent OPG applications. For the regulated hydroelectric facilities, the account shall continue to record the difference between OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan), and such forecast amounts underpinning the revenue requirement approved by the OEB.

For the regulated hydroelectric facilities, such monthly reference amount for OPG's RPP contributions shall continue to be 1/12 of the average annual forecast of $45.1M[14] reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321. The resulting monthly reference amount shall be $3.76M. For OPG's OPEB payments, the monthly reference amount for the regulated hydroelectric facilities shall continue to be 1/12 of the annual average forecast of $12.8M[15] reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321. The resulting monthly reference amount shall be $1.07M.

For the nuclear facilities, the account shall only record amortization and interest as the approved revenue requirements in this proceeding do not include RPP contributions and OPEB plan payments and instead reflect pension and OPEB costs calculated on an accrual basis.

[14] Ex. H1-1-1, Table 7, line 1 and EB-2016-0152 Payment Amounts Order, Appendix G, p. 12.
[15] Ex. H1-1-1, Table 7, line 1 and EB-2016-0152 Payment Amounts Order, Appendix G, p. 12.

2.11 Pension and OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was approved in EB-2013-0321 and was continued in subsequent proceedings. For the regulated hydroelectric facilities, the account will continue to record differences between: (i) OPG's actual pension and OPEB costs for its prescribed generating facilities determined using the accrual accounting method applied in OPG's audited consolidated financial statements; and, (ii) OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to OPG's prescribed generating facilities.

The account was originally established to record the above amounts for both regulated hydroelectric and nuclear facilities pending the outcome of an OEB generic proceeding on the regulatory treatment of pension and OPEB costs, in recognition that the OEB-approved revenue requirements during this period included RPP contributions and OPEB plan payments instead of pension and OPEB costs calculated on an accrual basis.

As the approved nuclear revenue requirements in this proceeding reflect pension and OPEB costs calculated on an accrual basis, the account shall only record amortization for the nuclear facilities.

Pursuant to the OEB's decision in EB-2013-0321 and subsequent proceedings, no interest is recorded in the account.

2.12 Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account

The Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account was established by the OEB on a generic basis in EB-2015-0040. The EB-2015-0040 Report of the OEB: *Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs* determined that the account will track the differences between the forecast pension and OPEB accrual amounts recovered in rates and the actual cash payments made for both pension and OPEB plans. The Report also determined that, for utilities for which the OEB previously established accounts to capture the difference between cash and accrual methods as an interim measure pending the outcome of the EB-2015-0040 consultation, this variance account would also record amounts collected relating to these previously approved accounts.

This account shall continue to have three sub-accounts, as described below.

For the nuclear facilities, the Primary Sub-account shall track the differences between actual pension and OPEB costs on an accrual basis[16] and OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) (i.e., cash payments). The sub-account shall also track amortization amounts for the Pension and OPEB Cash Versus Accrual Differential Deferral Account, for both regulated hydroelectric and nuclear facilities. When the cumulative accrual amount (including amortization amounts from the Pension and OPEB Cash Versus Accrual Differential Deferral Account) exceeds the cumulative actual cash payments, the sub-account will hold a credit balance. The opening monthly balance of the sub-account for each of regulated hydroelectric and nuclear facilities will only accrue carrying charges – in favour of ratepayers in the Carrying Charges Sub-Account – when it is in a credit position. The Contra Sub-Account shall continue to record offsetting entries with the Primary Sub-Account to enable book-keeping with offsetting entries. Carrying charges do not apply to this sub-account. The Carrying Charges Sub-Account shall continue to record interest at the OEB's prescribed Construction Work In Progress rate.

As tracking accounts, neither the Primary Sub-Account nor the Contra Sub-Account are subject to disposition. The Carrying Charges Sub-Account is subject to disposition. No interest shall be recorded on the balance of the Carrying Charges Sub-Account.

2.13 Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in EB-2014-0369 and continued in all subsequent OPG applications. The account shall continue to record the difference between the annual revenue requirement impact of the original Niagara Tunnel Project rate base addition disallowance of $28.0 million ordered in EB-

[16] The actual amount of pension and OPEB costs on an accrual basis is used as the basis for entries in the Primary Sub-Account in order to account for the interaction of this account with the Pension and OPEB Cost Variance Account.

2013-0321 and the varied disallowance of $6.4 million per EB-2014-0369. The payment amounts for the regulated hydroelectric facilities approved in this proceeding reflect the EB-2013-0321 disallowance and do not reflect the impact of the varied disallowance.

2.14 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account shall continue to record the revenue requirement impact on the prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"), measured against the forecast impact reflected in the revenue requirement approved by the OEB.[17] OPG shall not record the revenue requirement impact of a change in its nuclear liabilities related to the Bruce facilities in this account. In 2022, OPG shall record the return on rate base in the account using the weighted average accretion rate of 4.89%.[18] As the average unfunded nuclear liabilities are lesser than the asset retirement cost beginning in 2023, OPG shall record the return on rate base in the account in 2023-2026 using the OEB-approved weighted average cost of capital rates.[19]

OPG shall not record any interest on the balance of the Nuclear Liability Deferral Account.

2.15 Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. Inclusive of the amendments to O. Reg. 53/05 filed on November 5, 2021 that come into force on January 1, 2022, this account shall record the revenue requirement impact of the variances between the actual non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities and those forecast costs and firm financial

[17] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 6(2)7).
[18] Appendix A, Table 11, line 7, col. (c).
[19] Appendix A, Tables 12-15: line 4, col. (b) x col. (c) + line 5a, col. (b) x col. (c).

commitments reflected in the revenue requirement approved by the OEB.[20] As required by Section 6(2)4.1, such costs and firm financial commitments shall include planning, preparation and technology identification for the new facilities, as well as design, development and construction of the new facilities. Monthly reference amounts shall be $0.18M in 2022, $0.18M in 2023, $0.19M in 2024, $0.19M in 2025 and $0.19M in 2026, being 1/12 of the corresponding annual amounts of $2.2M, $2.2M, $2.3M, $2.3M, $2.3M reflected in the approved revenue requirements for 2022-2026.[21]

As found by the OEB in the EB-2020-0290 Decision and Order, the costs that OPG proposed, in this proceeding, to record in the Nuclear Development Variance Account with respect to the planning and preparation for the development of a new small modular reactor facility at Darlington shall be included in the variance account.

2.16 Bruce Lease Net Revenues Variance Account

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

This account shall continue to record differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. Such costs will continue to include the impact of any changes in OPG's liabilities for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations.

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[20] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 6(2)7.1).
[21] Ex. F2-1-1, Table 1, line 6, cols. (g) to (k).

The variance recorded in the account shall be determined by comparing (i) the quotient of the annual forecast amount of ($45.6M), ($38.7M), ($48.1M), ($46.5M) and ($38.3M) reflected in the revenue requirement approved by the OEB for each respective year from 2022 to 2026[22] and the approved nuclear production forecast for the corresponding year of 33.6 TWh, 31.2 TWh, 34.0 TWh, 31.1 TWh, and 21.9 TWh for each respective year from 2022 to 2026[23] ("rate of recovery"), multiplied by OPG's actual nuclear production from 2022 to 2026, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The rate of recovery shall be ($1.36)/MWh in 2022, ($1.24)/MWh in 2023, ($1.42)/MWh in 2024, ($1.50)/MWh in 2025, and ($1.75)/MWh in 2026.

The Derivative Sub-Account related to the previously existing derivative liability for the conditional supplemental rent rebate provision of the Bruce lease. As noted in the EB-2016-0152 Payment Amounts Order, the provision for a conditional supplemental rent rebate has now been removed and the derivative liability eliminated.[24] As of the effective date of the payment amounts established in this proceeding, OPG shall terminate the Derivative Sub-Account and transfer the remaining balance to, and record its subsequent amortization in the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

2.17 Nuclear Deferral and Variance Over/Under Recovery Variance Account

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

[22] Appendix A, Tables 1 to 5: line 20, for 2022 to 2026, respectively.
[23] Appendix A, Table 8, line 1.
[24] EB-2016-0152 Payment Amounts Order, Appendix G, p. 16.

2.18 Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account

The Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account was approved in EB-2018-0002. The account recorded the revenue requirement impact arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to Pickering station end-of-life dates that became effective December 31, 2017.

Pursuant to the EB-2018-0002 Decision and Order, the account entries were to continue until the effective date of this payment amounts order.[25] As such, no further additions are to be recorded to the account subsequent to the effective date of the nuclear payment amounts established in this proceeding, which incorporate the above changes to the Pickering station end-of-life dates. Only amortization is to be recorded in this account.

No interest shall be recorded in this account pursuant to the EB-2018-0002 Decision and Order.

2.19 SR&ED ITC Variance Account

The SR&ED ITC Variance Account was approved in EB-2016-0152. The account shall continue to record the difference between actual SR&ED ITCs attributed to the nuclear facilities as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB, including the tax on the difference. Such monthly reference amount shall be 1/12 of the corresponding annual amounts reflected in the revenue requirement approved by the OEB in this proceeding: $16.5M in 2022, $16.3M in 2023, $16.4M in 2024, $16.1M in 2025, and $15.9M in 2026.[26] The resulting monthly reference amounts shall be $1.4M in 2022, $1.4M in 2023, $1.4M in 2024, $1.3M in 2025, and $1.3M in 2026.

2.20 Fitness for Duty Deferral Account

The Fitness for Duty Deferral Account was approved by the OEB in EB-2016-0152. The account shall continue to record costs related to implementing the Canadian Nuclear Safety

[25] EB-2018-0002 Decision and Order, p. 1.
[26] Appendix A, Tables 17-21, line 28, col. (c).

Commission ("CNSC") Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, is a license requirement of the CNSC.

2.21 Rate Smoothing Deferral Account

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

According to O. Reg. 53/05 s. 5.5(1), an annual deferral amount will be recorded in this account from January 1, 2017 until the DRP ends (the "deferral period"). OPG shall set the annual deferral amounts as follows for the IR term, to be recorded monthly on a straight-line basis: \$82.4M in 2022, \$125.7M in 2023, \$0M in 2024, \$0M in 2025, and \$0M in 2026.[27]

Per O. Reg. 53/05 s. 5.5(2), the deferral account shall record interest on the balance at the following OEB-approved long-term debt rates reflecting OPG's cost of long-term borrowing, compounded annually: 3.61% for 2022, 3.49% for 2023, 3.61% in 2024, 3.65% in 2025, and 3.65% in 2026.[28]

2.22 Pickering Closure Costs Deferral Account

The Pickering Closure Deferral Account was established by OPG in accordance with section 5.6 of O. Reg. 53/05. The account shall continue to record any employment-related costs and non-capital costs related to third party service providers incurred by OPG that arise from any activities in furtherance of Pickering closure, on the basis set out in Appendix F.

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[27] The derivation of the annual deferral amounts is shown in Appendix G, Chart 4.
[28] Long-term debt rates for 2022-2026 are presented at Appendix A, Tables 11-15: line 3, col. (c).

3.0 INTEREST

Except whether otherwise stated as of the effective date of the payment amounts established in this proceeding, OPG shall record interest on the balances in all deferral and variance accounts using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts. Unless stated otherwise, OPG shall apply simple interest to the opening monthly balance of the accounts until the balances are fully recovered or refunded.

ATTACHMENT 1: DRP REVENUE REQUIREMENT (CAPITAL COMPONENT)

Shown below is the derivation of amounts for the Darlington Refurbishment Program capital component that are reflected in the nuclear revenue requirements approved by the OEB in this proceeding and form the corresponding reference amounts for the Capacity Refurbishment Variance Account.[29]

Line No.	Category	Note	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DRP Average Rate Base (Ex. B3-1-1, Table 2, lines 2 and 10)		4,978.0	4,815.3	7,114.2	8,191.6	8,853.7
2	D2O Average Rate Base	1	366.5	354.5	342.4	330.4	318.4
3	**Total Rate Base**		**5,344.5**	**5,169.8**	**7,456.7**	**8,522.1**	**9,172.1**
4	Weighted Average Cost of Capital (PAO App. A, Tables 11-15)		5.89%	5.83%	5.90%	5.92%	5.92%
5	**Cost of Capital** (line 3 x line 4)		**314.9**	**301.3**	**439.8**	**504.6**	**543.3**
	Depreciation						
6	DRP (PAO App. A, Table 10, col. (b))		163.4	163.4	249.8	298.9	334.6
7	D2O (PAO App. A, Table 10, col. (b))		12.0	12.0	12.0	12.0	12.0
8	**Total Depreciation**		**175.4**	**175.4**	**261.8**	**311.0**	**346.6**
	Regulatory Taxable Income Impacts						
9	ROE (line 3 x 45% x 8.66%)		208.3	201.5	290.6	332.1	357.4
10	Depreciation (line 8)		175.4	175.4	261.8	311.0	346.6
11	CCA		(523.6)	(550.7)	(540.3)	(538.9)	(520.2)
12	**Net Increase (Decrease) in Regulatory Taxable Income**		**(139.9)**	**(173.8)**	**12.1**	**104.1**	**183.8**
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))		**(46.6)**	**(57.9)**	**4.0**	**34.7**	**61.3**
15	**Total DRP Capital Revenue Requirement** (line 5 + line 8 + line 14)		**443.6**	**418.8**	**705.7**	**850.3**	**951.2**
16	**Monthly DRP Capital Reference Amount** (line 15 / 12)		**37.0**	**34.9**	**58.8**	**70.9**	**79.3**

Note:
1 Calculated as PAO App. A: Table 9, col. (f) less Table 10, col. (e).

[29] The calculation is presented in the same manner as Ex. L-H1-01-Staff-328, Chart 2.

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

EB-2020-0290 Decision and Order, Schedule A (OEB Approved Settlement Proposal), p. 30.

Scope of Account

OPG shall establish, on a final basis, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, effective January 1, 2021, to record the revenue requirement impact arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to the Pickering station end-of-life dates, for OPG's prescribed nuclear facilities.

Entry 1: Nuclear liability revenue requirement for prescribed facilities

Entry	Debit	Credit
DR/CR Depreciation Expense	x,xxx	x,xxx
DR/CR Return on Rate Base	x,xxx	x,xxx
DR/CR Income Tax Expense	x,xxx	x,xxx
DR/CR Used Fuel Storage and Disposal Variable Expense	x,xxx	x,xxx
DR/CR Low & Intermediate Level Waste Management Variable Expense	x,xxx	x,xxx
CR/DR Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account	x,xxx	x,xxx

To record the impact on nuclear liabilities costs resulting from changes in end-of-life dates on Asset Retirement Cost ("ARC") depreciation, the associated impacts on the return on rate base and variable used fuel and waste management expenses, and the tax impact of the settlement with customers of the net amount.

Entry 2: Non-ARC revenue requirement impact for prescribed facilities

Entry	**Debit**	**Credit**
DR/CR Depreciation Expense	x,xxx	x,xxx
DR/CR Income Tax Expense	x,xxx	x,xxx
CR Return on Rate Base		x,xxx
CR/DR Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account	x,xxx	x,xxx

To record the impact of changes in Pickering station lives on non-ARC depreciation expense, the associated impact on the return on net rate base through the change in accumulated depreciation, and the tax impact of the settlement with customers of the net amount.

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

The account entries will continue until the effective date of the next payment amounts order incorporating the corresponding changes to the Pickering station end-life dates in nuclear payment amounts.

Pickering Closure Costs Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Ontario Energy Board Act, 1998; Ontario Regulation 53/05 s. 5.6.

Scope of Account

OPG shall establish the Pickering Closure Costs Deferral Account in accordance with section 5.6 of Ontario Regulation 53/05. The account shall record any employment-related costs and non-capital costs related to third party service providers incurred by OPG that arise from any activities in furtherance of Pickering closure. Pickering closure shall mean the closure or decommissioning of the Pickering A Nuclear Generating Station (also known as Pickering Units 1-4) or Pickering B Nuclear Generating Station (also known as Pickering Units 5-8), or the retirement of a generating unit at these stations from electricity generation. Pickering closure costs can be incurred before or after the closure of a Pickering unit, but do not include costs that are eligible for reimbursement to OPG under the Ontario Nuclear Funds Agreement.

Entry	Debit	Credit
DR Pickering Closure Costs Deferral Account	x,xxx	
CR OM&A / Other Expenses		x,xxx

OPG shall record Pickering closure costs in the deferral account as they are reflected in the audited financial statements approved by OPG's Board of Directors. 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.

Ontario Regulation 53/05 requires recovery of the account balance and related income tax effects on a straight line basis over a period not to exceed 10 years, beginning on the day the last generating unit of the Pickering A Nuclear Generating Station and Pickering B Nuclear Generating Station permanently stops generating electricity, to the extent that the OEB is satisfied that the costs were prudently incurred and are accurately recorded in the account.

Clarington Corporate Campus Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

EB-2020-0290 Decision and Order, Schedule A (OEB Approved Settlement Proposal), p. 29.

Scope of Account

OPG shall establish the Clarington Corporate Campus Deferral Account, effective January 1, 2022, to record, for the nuclear facilities, the revenue requirement impacts of capital expenditures and operating costs for OPG's planned Clarington Corporate Campus, calculated on the same basis as OPG's existing asset service fee methodology reflected in the revenue requirements approved in the EB-2020-0290 proceeding.

Entry	Debit	Credit
DR Clarington Corporate Campus Deferral Account	x,xxx	
CR OM&A Expenses – Asset Service Fees		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.

The account entries will continue until the effective date of the next payment amounts order incorporating the revenue requirement impacts of the Clarington Corporate Campus in nuclear payment amounts.

Sale of Unprescribed Kipling Site Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

EB-2020-0290 Decision and Order, Schedule A (OEB Approved Settlement Proposal), p.30.

Scope of Account

OPG shall establish the Sale of Unprescribed Kipling Site Deferral Account, effective January 1, 2022, to track 23% of the net proceeds arising from any sale of OPG's unprescribed site located at 800 Kipling Avenue in Toronto during the 2022-2026 period.[1] The purpose of this tracking account is to enable parties to a future payment amounts proceeding to take a position that some or all portion of this amount should be credited to ratepayers.

Entry	**Debit**	**Credit**

As this is a tracking account only, no accounting entries are required for this account

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

[1] The 23% represents the portion of the site attributable to use by the regulated assets (Ex. JT3.12).

Earnings Sharing Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

EB-2020-0290 Decision and Order, Schedule A (OEB Approved Settlement Proposal), p. 29.

Scope of Account

OPG shall establish the Earnings Sharing Deferral Account, effective January 1, 2022, to record 50% of any regulated earnings for its combined 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.

Entry	Debit	Credit
DR/CR Revenue	x,xxx	x,xxx
CR/DR Earnings Sharing Deferral Account	x,xxx	x,xxx

For the purpose of recording entries in the account, the OEB-approved ROE rate for the above 5-year period shall be the rate base-weighted average of the 9.33% ROE rate approved in EB-2013-0321[2] for the regulated hydroelectric facilities and the 8.66% ROE rate approved in EB-2020-0290[3] for the nuclear facilities. The balance in the account will be considered for disposition following the completion of the above 5-year period.

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.

[2] The 9.33% ROE rate represents the average of 9.36% (EB-2013-0321 Payment Amounts Order, App. A, Table 5b, line 5, col. (c)) for 2014 and 9.30% for 2015 (EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 5, col. (c)) approved in EB-2013-0321.
[3] Appendix A, Tables 11-15, line 5a, col. (c).

Impact for IFRS Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

EB-2020-0290 Decision and Order, Schedule A (OEB Approved Settlement Proposal), p. 29.

Scope of Account

OPG shall establish the Impact for IFRS Deferral Account, effective January 1, 2022, to record financial impacts of transition to and implementation of IFRS from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the *Securities Act* (Ontario).

Entry	Debit	Credit
DR/CR Impact for IFRS Deferral Account	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, as attributed to regulated operations (nuclear and regulated hydroelectric).

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

PAYMENT AMOUNT SMOOTHING

1.0 PURPOSE

This evidence sets out OPG's revised proposal for smoothing payment amounts during the 2022-2026 IR term pursuant to the OEB's Decision and Order in this proceeding dated November 15, 2021 (the "Decision"). In addition, this evidence includes a comparison of OPG's smoothing proposal against a range of alternative scenarios directed by the Decision (p. 53).

2.0 OVERVIEW

OPG proposes smoothed Weighted Average Payment Amount ("WAPA")[1] of $74.63/MWh in 2022, $75.38/MWh in 2023, $75.40/MWh in 2024, $75.29/MWh in 2025, and $74.05/MWh in 2026, resulting in entries to the rate smoothing deferral account ("RSDA")[2] of $66.7M in 2022, $110.5M in 2023, $0.0M in 2024, $0.0M in 2025 and $0.0M in 2026. This proposal is pursuant to the requirements of O. Reg. 53/05 (the "Regulation") and is consistent with the principles established in EB-2016-0152. The smoothing proposal is also consistent with customer feedback received during OPG's customer engagement (Ex. A2-2-1) and ensures that there are no negative deferral amounts in any year of the IR term.

The average residential customer bill impact of OPG's revised rate proposal[3] set out in this Exhibit is 0.17% annually or approximately $0.19 on a typical monthly residential customer bill each year.

Section 3.0 summarizes the rate smoothing requirements set out in the Regulation. Section 4.0 describes the inputs into the calculation of the WAPA. Section 5.0 sets out OPG's proposal,

[1] PAO Appendix B, Table 2A, line 7.
[2] PAO Appendix B, Table 1, line 5.
[3] PAO Appendix B, Table 2A, lines 4 and 5.

evaluates the proposal using the established principles, and compares the proposal against alternatives.

3.0 REQUIREMENTS OF O. REG. 53/05

The Regulation sets out certain processes and parameters that OPG and the OEB must follow regarding the smoothing of OPG's payment amounts during the deferral period.[4]

The Regulation requires that, for each year of the deferral period, the OEB must approve a nuclear revenue requirement and must also determine a portion of that approved revenue requirement to defer.[5] The OEB is required to make this determination with "a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period."[6] The "calculation period" is defined in s. 0.1(1) of the Regulation as:

> each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period.

Subparagraph 12(ii) of subsection 6(2) of the Regulation requires that the OEB determine nuclear revenue requirements and amounts to be deferred on a five-year basis for the first 10 years of the deferral period (2017-2026). Subparagraph 12(iv) requires that the balance in the RSDA be recovered on a straight-line basis over a period not to exceed 10 years beginning when the Darlington Refurbishment Program ends.

3.1 Calculation of the Weighted Average Payment Amount

Section 0.1(1) of the Regulation defines OPG's WAPA for a year through the following formula:

[4] O. Reg. 53/05 defines the deferral period which commences January 1, 2017 and ends when the Darlington Refurbishment Project ends.
[5] O. Reg. 53/05, s. 5.5 (1).
[6] O. Reg. 53/05, s. 6 (2), sub-para. 12 (i).

$$\frac{\mathbf{((NPA + NPR) \times NPF) + ((HPA + HPR) \times HPF)}}{\mathbf{(NPF + HPF)}}$$

NPA (**Nuclear Payment Amount**) is the Board-approved payment amount for the year in respect of the nuclear facilities

NPR (**Nuclear Payment Riders**) is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the RSDA

NPF (**Nuclear Production Forecast**) is the Board-approved production forecast for the nuclear facilities for the year

HPA (**Hydroelectric Payment Amount**) is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the [prescribed] hydroelectric facilities

HPR (**Hydroelectric Payment Riders**) is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities

HPF (**Hydroelectric Production Forecast**) is the Board-approved production forecast for the hydroelectric facilities for the year

The NPR, NPF, HPA, HPR, and HPF are collectively referred to as the “inputs”, since they are the values that the OEB must approve to determine the annual amounts of nuclear revenue requirement to be recorded in the RSDA for the 2022-2026 period. While the NPA is also approved by the OEB, it is an output (rather than an input) of the prescribed formula since it will reflect the annual deferral of nuclear revenue requirement.

4.0 INPUTS TO RATE SMOOTHING

This section identifies the values for the inputs required to determine annual deferral amounts to be recorded in the RSDA during the IR term.

Each of the following steps is necessary in order to determine the amounts to be deferred in the RSDA:

Step	Action	Basis in O. Reg. 53/05
1	Approve annual nuclear revenue requirements for the five-year IR Term, absent any deferral	s. 5.5(1)(a) s. 6(2)12(ii) s. 6(2)12(iii)
2	Approve required WAPA inputs for each year	
3	Determine the annual change in the WAPA, applying the principles established in EB-2016-0152 to assess options with a view to making more stable the year-over-year changes in the WAPA over each calculation period ("Smoothed WAPA Rate")	s. 0.1(1) s. 6(2)12(i)
4	Using the Smoothed WAPA Rate determined in Step 3 and the inputs approved in Step 2, determine the annual NPA	s. 0.1(1)
5	Determine annual deferred amount to be recorded in RSDA for each year of the five year term [Step 1 - (NPA x NPF)]	s. 5.5(1)(b) s. 6(2)12(i)

The nuclear revenue requirements for the IR term reflecting the Decision are summarized in Chart 1 below.

Chart 1: Nuclear Revenue Requirement[7]

	2022	2023	2024	2025	2026
Nuclear Revenue Requirement Net of Stretch Factor ($M)	$3,515.5	$3,430.0	$3,518.3	$3,197.6	$2,439.5

Hydroelectric Payment Amount (HPA): The 2022-2026 HPA is $43.88/MWh, being the 2021 hydroelectric payment amount that is to remain in effect during the IR term pursuant to O. Reg. 53/05.

Nuclear Payment Rider (NPR) and Hydroelectric Payment Rider (HPR): Per the Decision, OPG is to recover certain audited December 31, 2019 balances in the deferral and variance accounts, except for $40.0M of debit balances recorded in the Hydroelectric Surplus Baseload Generation Variance Account and the impacts of the OEB's findings on the D2O Storage Project, and as adjusted for the 2020-2021 amortization amounts approved in EB-2016-0152 and EB-2018-0243 and other adjustments, through nuclear payment riders and hydroelectric payment riders over the January 1, 2022 to December 31, 2026 period.[8] The nuclear payment rider[9] is $1.16/MWh in 2022, $1.25/MWh in 2023, $1.15/MWh in 2024, $5.34/MWh in 2025, and $7.58/MWh in 2026. The hydroelectric payment rider[10] is $1.03/MWh in 2022, 2023, and 2024, and $0.69/MWh in 2025 and 2026.

The rate smoothing proposal does not reflect any payment riders for recovery (or refund) of deferral and variance account balances after December 31, 2019, as none of these balances have been approved. Any payment riders the OEB may establish for these balances in the future would be separate from the rate smoothing proposal and would not affect the revenue requirement deferral amounts approved in this proceeding. In a subsequent proceeding, the OEB could assess the future bill impact of potential payment riders for recovery (or refund) of any deferral and variance account amounts approved.

Determination of Annual Change in WAPA: Pursuant to the Regulation, the calculation period in this application is 2022-2026. OPG calculates WAPA for each year in the calculation

[7] PAO, Appendix A, Tables 1-5, Line 26.
[8] PAO, Appendix C, Table 1, col. (f) and PAO Appendix D, Table 1, col. (f).
[9] PAO, Appendix D, Table 1, Line 32.
[10] PAO, Appendix C, Table 1, Line 23.

period as demonstrated in the draft Payment Amounts Order ("PAO"), Appendix B, Table 2. The Regulation requires that a rate smoothing proposal result in a WAPA that is more stable than would be the case without deferral of nuclear revenue requirement.[11]

Total OPG Regulated Production: Consistent with the approach underlying the rate smoothing proposal in EB-2016-0152 and as applied in Ex. I1-3-2, for the hydroelectric facilities, OPG has used the average of the 2014 and 2015 OEB-approved hydroelectric production.[12] For the purpose of WAPA smoothing, this amount is used for each year in the 2022-2026 period. Per the Decision[13], the nuclear production forecast is 33.6 TWh in 2022, 31.2 TWh in 2023, 34.0 TWh in 2024, 31.1 TWh in 2025, and 21.9 TWh in 2026.

4.1 Post-2026 Projections used in Smoothing Analysis

An understanding of forecast nuclear costs and production for the entire deferral and recovery period is necessary context to determine the appropriate rate smoothing proposal under the Regulation. While it is not possible to precisely forecast revenue requirement and production over 15 years, Chart 2 provides OPG's view of the approximate longer-term nuclear revenue requirements and production, along with indicative average nuclear rates that would result for the 2027-2036 period without smoothing (in nominal dollars).

Chart 2: Nuclear Revenue Requirement, Production and Average Unsmoothed Rate

	2022-2026	2027-2031[14]	2032-2036[15]
Anticipated Revenue Requirement[16] ($B)	$16.1[17]	$15.9	$15.8
Anticipated Production (TWh)	152[18]	134	141
Average Rate ($/MWh)	$106	$119	$112

In consideration of the magnitude of costs being deferred, OPG's smoothing proposal continues to assume that the RSDA balance is recovered over the maximum ten-year period.

[11] O. Reg. 53/05, s. 6 (2)(12)(i); relative to WAPA as defined in s. 0.1 (1).
[12] 33 TWh, per EB-2013-0321, Decision with Reasons, November 20, 2014, p. 9.
[13] EB-2020-0290 Decision and Order, Schedule A, p. 25.
[14] Per Ex. I1-3-2, Chart 2
[15] *Ibid.*
[16] Excludes Pickering closure costs that will be recorded in the Pickering Closure Costs Deferral Account.
[17] Sum of 2022-2026 Revenue Requirement net of Stretch Factor from PAO Appendix A, Tables 1-5, Line 26.
[18] Sum of 2022-2026 Production per PAO, Appendix B, Table 1, Line 2.

The average nuclear rate (absent rate smoothing) for the 2032 to 2036 period reflects the stabilization of OPG's operations post completion of the Darlington Refurbishment Program and activities associated with the end of Pickering commercial operations. OPG believes that the average forecast 2032 to 2036 rate of $112/MWh is therefore a reasonable proxy for the rate that will prevail after the rate smoothing deferral and recovery cycle (i.e., the "new normal").

5.0 RATE SMOOTHING PROPOSAL AND ALTERNATIVES

Exhibit I1-3-2 provided OPG's initial rate smoothing proposal as compared to several alternatives, based on the proposed nuclear revenue requirements and production forecast. Of these alternatives, OPG proposed Alternative E, which resulted in an annual increase to the WAPA of 4% in 2022, 1% in 2023, 1% in 2024, 1% in 2025, and 1% in 2026. OPG proposed this approach because, in OPG's view, it provided an effective balance between financial viability and customer-focused criteria outlined in Ex. I1-3-2, Section 5.3.[19]

After updating for the impact of the Decision, an annual WAPA increase of 4% in 2022 and 1% in each of 2023-2026 would result in aggregate net negative deferral amounts over the IR term. In view of this, OPG has revised its rate smoothing proposal from the pre-filed evidence to limit the WAPA increase in any single year to the lowest amount that does not result in a negative deferral amount in that year. This scenario is presented as Alternative B, below.

In its Decision, the OEB directed OPG to include at least three alternative scenarios to OPG's proposed option:

[19] As noted at Ex. I1-3-2, p. 9, OPG uses two financial metrics to gauge the potential impact of rate smoothing alternatives on the financial viability criterion: the Funds from Operations ("FFO") to Debt ratio and the Cash Flow from Operations Pre Working Capital ("CFO") to Debt Ratio. These are the primary metrics currently used by S&P Global Ratings ("S&P") and Moody's Investors Service ("Moody's"), respectively, to evaluate OPG's financial risk as part of their credit rating process. A forecast of less than 13% consistently on the FFO to Debt metric could result in a negative rating action from S&P. A forecast of less than 12% on the Cash Flow to Debt metric on a sustained basis could lead to a downgrade by Moody's. As such, the financial viability criterion can ultimately affect OPG's cost of borrowing.

- An illustrative example of an alternative that recovers the entire proposed nuclear revenue requirement for the 2022-2026 period absent any rate smoothing for analysis and comparison purposes only (presented below as “Illustrative Scenario D”);
- An alternative that recovers less revenue requirement in 2022 compared to OPG’s preferred option (presented below as “Alternative A”); and
- An alternative that recovers more revenue requirement in 2022 compared to OPG’s preferred option (presented below as “Alternative C”).

Chart 3 below provides a summary of OPG’s rate smoothing proposal as compared to the three alternative scenarios.

Chart 3: Smoothing Alternatives – Outcomes

	Smoothing Alternatives			Illustrative – No Deferrals
Scenario	**A**	**B (OPG Proposal)**	**C**	**D**
2022-2026 Change in WAPA	y1: 3.0% y2: 1.0% y3: 0.8% y4: 0.3% y5: -1.6%	y1: 4.0% y2: 1.0% y3: -0.2% y4: 0.3% y5: -1.6%	y1: 5.0% y2: 1.0% y3: -1.2% y4: 0.3% y5: -1.6%	y1: 5.1% y2: 1.9% y3: -2.5% y4: 0.3% y5: -1.6%
2027-2036 Average Change in WAPA	1.3%	1.2%	1.2%	1.2%
Peak RSDA Balance ($B)	$0.9	$0.8	$0.7	$0.6
2022-2026 Interest on Cumulative Deferral Amounts ($M)	$144	$130	$115	$103
2022-2026 Interest on IR Term Deferral Amounts ($M)	$41	$26	$12	$0
2017-2026 Total Interest ($B)	$0.40	$0.36	$0.32	$0.29
Deferral Amounts (2022-2026) ($M)	$271.5	$177.3	$83.0	None
Interest Cost / Deferred Revenue Ratio	0.5	0.5	0.6	0.6
Lowest Cash Flow from Operations pre Working Capital to Debt Ratio (2022-2026)	11.8%	12.0%	12.3%	12.3%
Lowest Funds from Operations to Debt Ratio (2022-2026)	Below 13%			
Nuclear Payment Amount Transition Impact ($/MWh)	$3.44	$4.00	$4.55	$5.04
Average Annual Bill Impact (2022-2026) in %	0.17%	0.17%	0.17%	0.17%
Average Annual Bill Impact (2022-2026) in $	$0.19	$0.19	$0.19	$0.19
Average Annual Bill Impact (2022-2036) in %	0.21%	0.20%	0.20%	0.19%
Average Annual Bill Impact (2022-2036) in $	$0.24	$0.23	$0.23	$0.22

Alternative A, in which OPG recovers less revenue requirement in 2022 as compared to OPG's proposed Alternative B, assumes a 3% WAPA increase in 2022, a 1% increase in 2023, and changes in 2024-2026 that recover the lowest amount of revenue requirement necessary to ensure no negative deferral amounts in a year. This alternative results in higher interest costs and a slightly lower transition payment amount than Alternative B. It does not enable OPG to meet its financial viability criterion, which is assessed based on at least one of the two credit metrics being within threshold at all times during the 2022-2026 period (i.e., 12.0% for Cash Flow from Operations pre Working Capital to Debt ratio and 13.0% for Funds from Operations to Debt ratio).

Alternative C, in which OPG recovers more revenue requirement in 2022 as compared to OPG's proposed Alternative B, assumes a 5% WAPA increase in 2022, a 1% increase in 2023, and changes in 2024-2026 that recover the lowest amount of revenue requirement necessary to ensure no negative deferral amounts in a year. This alternative results in lower interest costs and a slightly higher transition payment amount than Alternative B.

All three Alternatives result in similar average customer bill impacts and, as required by Regulation, result in more stable changes in the WAPA as compared to Illustrative Scenario D. In consideration of inherent uncertainties of longer-term forecasts, all three Alternatives also present an acceptable estimated transition impact by the end of 2036, in OPG's view. All three Alternatives are also consistent with feedback received through the customer engagement process, with forecasted interest over the 2017-2036 period being lower than $500M. In all three Alternatives, the lowest values for the Cash Flow from Operations pre Working Capital to Debt ratio metric are in 2022.

With respect to the direction in the Decision for OPG to identify the best credit metrics alternative (p. 54), both Alternative B and Alternative C enable OPG to meet its financial viability criterion as at least one of the two financial metrics (i.e., Cash Flow from Operations pre Working Capital to Debt ratio) is above the threshold in all years of the IR term. Alternative C supports somewhat stronger credit metrics than Alternative B and is therefore the best alternative from that standpoint. However, because Alternative C results in somewhat greater year-over-year variability in WAPA changes, OPG believes that its proposed Alternative B represents a more balanced option.

The proposed nuclear payment amounts presented in PAO Appendix B have been determined based on OPG's proposed Alternative B, as detailed in Chart 4 below.

Chart 4[20]

OPG Proposed Deferred Nuclear Revenue Requirement

	2022	2023	2024	2025	2026
Revenue Requirement ($M)	$ 3,515.5	$ 3,430.0	$ 3,518.3	$ 3,197.6	$ 2,439.5
Forecast Production (TWh)	33.6	31.2	34.0	31.1	21.9
Smoothed Rate ($/MWh)	$ 102.64	$ 106.30	$ 103.48	$ 102.85	$ 111.33
Smoothed Revenues ($M)	$ 3,448.7	$ 3,319.5	$ 3,518.3	$ 3,197.6	$ 2,439.5
Deferred Revenue Requirement ($M)	$ 66.7	$ 110.5	$ -	$ -	$ -

[20] PAO Appendix B, Table 1.