EB-2020-0290

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.

ONTARIO POWER GENERATION INC.

SETTLEMENT PROPOSAL

JULY 16, 2021

Ontario Power Generation Inc.
EB-2020-0290
Settlement Proposal

TABLE OF CONTENTS

SECTIONS

Section 1: EB-2020-0290 Settlement Proposal Overview
Section 2: Key Components of Settlement
Section 3: Settlement by Issue

APPENDICES

Appendix A: Reporting and Record Keeping Requirements
Appendix B: Draft Payment Amounts Order

LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live Excel models have been filed together with and form an integral part of this Settlement Proposal:

Revised Revenue Requirement Work Form

SECTION 1 – EB-2020-0290 SETTLEMENT PROPOSAL OVERVIEW

Filed with OEB: July 16, 2021

1. INTRODUCTION

This Settlement Proposal is filed with the Ontario Energy Board ("**OEB**") in connection with Ontario Power Generation Inc.'s (the "**Applicant**" or "**OPG**") payment amounts application made under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "**Act**") seeking approval for changes in payment amounts for the output of its nuclear generating facilities in each of the five years beginning January 1, 2022 and ending on December 31, 2026. OPG also sought to maintain, with no change, the base payment amount it charges for the output of its regulated hydroelectric generating facilities at the payment amount in effect December 31, 2021, for the period from January 1, 2022 to December 31, 2026 (OEB Docket Number EB-2020-0290) (the "**Application**").

As set forth herein, the Settlement Proposal contains a comprehensive settlement of all issues within the Application, with the exception of three outstanding issues (as detailed in part 5 and also Section 3 below) related to the in-service additions for OPG's Heavy Water Storage and Drum Handling Facility (the "**D2O Project**") and associated deferral and variance account balances, matters related to small modular reactors ("**SMR**"), and the appropriate rate smoothing.

2. BACKGROUND

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 panels of witnesses. 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 ("**Issues List**") is attached as Schedule A to the Decision on Motions. On June 7, 2021, the parties proceeded to a Settlement Conference.

3. THE SETTLEMENT PROCESS

Pursuant to Procedural Order No. 1, a Settlement Conference was convened on June 7, 2021 and was extended twice, continuing until June 14, 2021. The Settlement Conference was conducted in accordance with the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Settlement Conferences* (the "**Practice Direction**").

Karen Wianecki acted as facilitator for the Settlement Conference.

OPG and the following Intervenors (the "**Intervenors**") participated in the Settlement Conference:

Association of Major Power Consumers in Ontario ("**AMPCO**")
Canadian Manufacturers & Exporters ("**CME**")
Consumers Council of Canada ("**CCC**")
Energy Probe Research Foundation ("**Energy Probe**")
Environmental Defence Canada Inc. ("**Environmental Defence**")
London Property Management Association ("**LPMA**")
Ontario Association of Physical Plant Administrators ("**OAPPA**")
Ontario Sustainable Energy Association ("**OSEA**")
Power Workers' Union ("**PWU**")
Quinte Manufacturers Association ("**QMA**")
School Energy Coalition ("**SEC**")
Society of United Professionals ("**Society**")
Vulnerable Energy Consumers Coalition ("**VECC**")

OPG and the Intervenors are collectively referred to below as the "**Parties**".

OEB Staff also participated in the Settlement Conference. The role adopted by OEB Staff is set out in page 6 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who participated in the Settlement Conference are bound by the same confidentiality and settlement privilege requirements that apply to the Parties to the proceeding.

Notwithstanding any other wording in this Settlement Proposal, Environmental Defence is not supporting nor opposing any elements of this Settlement Proposal. For further clarity, where this Settlement Proposal refers to the "Parties" agreeing to or accepting something, that does not include Environmental Defence. Environmental Defence's lack of opposition does not imply that it agrees that expenditures addressed herein, such as those for the Pickering Nuclear Generation Station life extension, are appropriate or cost-effective. Environmental Defence takes no position on the Pickering Nuclear Generation Station life extension costs on the basis of Procedural Order No. 2, which ruled that a cost-benefit analysis of the life extension is out of scope for this payment amounts proceeding.

4. SETTLEMENT PROPOSAL PREAMBLE

This document comprises the Settlement Proposal and is presented jointly to the OEB by the Parties. This document is called a "**Settlement Proposal**" because it is a proposal by the Parties to the OEB to settle the issues in this proceeding identified as settled in this Settlement Proposal. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later

in this Preamble, this Settlement Proposal is subject to a condition subsequent: that if it is not accepted by the OEB in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential and privileged in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings*, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not in attendance via video conference at the settlement conference but were (i) any persons or entities that the Parties engaged to assist them with the Settlement Conference, and (ii) any persons or entities from whom the Parties sought instructions with respect to the negotiations, in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions as the Parties.

As per pages 6-7 of the Practice Direction, OEB Staff will file a submission with the OEB commenting on two aspects of the Settlement Proposal: (i) whether the Settlement Proposal represents an acceptable outcome from a public interest perspective, and (ii) whether the accompanying explanation and rationale is adequate to support the Settlement Proposal.

This Settlement Proposal is in part organized in accordance with the Issues List. This Settlement Proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence submitted for the record in this proceeding. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the written responses to interrogatories and technical conference undertakings, and other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal and the attachments to this document (the "**Attachments**").

The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and

the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the Settlement Proposal. The Parties acknowledge that the Appendices were prepared by OPG. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

The final agreements of the Parties following the Settlement Conference are set out below. The Parties explicitly request that the OEB consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Proposal. Reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this Settlement Proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept the Settlement Proposal in its entirety, then there is no agreement, unless the Parties agree, in writing, that the balance of this Settlement Proposal may continue as valid settlement subject to any revisions that may be agreed-upon by the Parties.

It is further acknowledged and agreed that none of the Parties will withdraw from this agreement under any circumstances, except as provided under Rule 30.05 of the OEB's *Rules of Practice and Procedure.*

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must concur with any revised settlement proposal, or take no position, prior to its resubmission to the OEB for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the agreement by the Parties to the settlement of any item shall be interpreted as being for the purpose of settlement of this case only and not a statement or acknowledgement of principle applicable in any other situation. Where, if at all, the Parties have agreed that a particular principle should be applicable generally, this Settlement Proposal states so expressly. The Parties understand this to be consistent with OEB policy, under which settlements and their approval by the OEB are considered to be specific to the facts of the particular case, and not precedents or statements of principle unless clearly so stated.

In this Settlement Proposal, where any of the Parties "accept" the evidence of OPG, or "agree" to a revised term or condition, including a revised budget or forecast, then, unless expressly stated to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

Except for those parts of this Settlement Proposal that are expressly agreed to apply for a period of time beyond the 2022-2026 period, it is also acknowledged and agreed that this Settlement Proposal is without prejudice to any of the Parties or the OEB re-examining the items settled herein in any subsequent proceeding and taking positions or rendering decisions inconsistent with the resolution of these items in this Settlement Proposal. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Settlement Proposal, if contrary to the terms of this Settlement Proposal, should be applicable to OPG for any part of the 2022-2026 period, unless otherwise required by applicable laws.

5. SETTLEMENT PROPOSAL OVERVIEW

The Parties are pleased to advise the OEB that they have reached a substantial, but not complete, agreement on almost all issues in this proceeding, specifically:

"**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	issues settled:[1] **1.1, 2.1, 2.2, 3.1, 4.1, 5.1, 6.1, 6.2, 7.1-7.5, 8.1, 9.1, 10.1-10.7, 11.1, 11.2, 12.1, 12.2, 13.3, 13.4, 13.5, 16.1**
"**Partial Settlement**" means an issue for which there is partial settlement, as OPG and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	issues partially settled: **1.2, 13.1, 13.2, 14.1,**
"**No Settlement**" means an issue for which no settlement was reached. Unless otherwise noted in this Settlement Proposal, OPG and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	issues not settled: **7.6, 15.1**

With respect to Issues 1.2, 13.1 and 14.1, denoted as Partial Settlement, the Parties settled on all matters within the issues, with the exception of (i) the recording of small modular reactor ("**SMR**") related costs in the Nuclear Development Variance Account in

[1] Issues 5.1, 10.6 and 10.7 are subject to any adjustments for the OEB's decision on the D2O Project.

the context of the issue identified by the OEB in its Decision on Issues List, dated May 20, 2021[2], (ii) consideration of SMRs as a component of OPG's customer engagement process, and (iii) SMR-related reporting and record keeping requirements.

The Parties did not settle Issue 7.6 as to whether the proposed in-service additions for the D2O Project are reasonable. Issue 7.6 is the only unsettled or partially settled issue that has an impact on the 2022-2026 nuclear revenue requirements. As a result of there being no settlement on the D2O Project, Issue 13.2 is denoted as "Partial Settlement" due to deferral and variance account balances associated with the D2O Project. Issue 13.2 is otherwise settled.

With respect to Issue 15.1, the Parties agree to defer the consideration of rate smoothing to the process of establishing the final payment amounts order arising from the OEB's decision on this Settlement Proposal and the remaining issues to be considered by the OEB in the pending hearing. OPG will file, under separate cover, its revised rate smoothing proposal based on the Settlement Proposal. This rate smoothing proposal provides the necessary information to support the updated smoothed nuclear payment amounts, deferred revenue amounts and bill impacts as set out in this Settlement Proposal, including the appended Draft Payment Amounts Order ("**PAO**"). The Parties note that OPG's rate smoothing proposal may be updated as part of the process of establishing the final payment amounts order after the OEB issues its decision on this Settlement Proposal and the partially settled and unsettled issues. Parties will have the opportunity to make submissions on OPG's revised smoothing proposal during the process of establishing the final payment amounts order.

The changes to components of OPG's proposed nuclear revenue requirements and production forecast agreed to by the Parties are as identified in Tables 1-5 below. The Parties note that the "Settled Amounts" in Table 1-5 below are subject to the OEB's determinations on the partially settled and unsettled issues and the agreement to update the proposed Return on Equity ("**ROE**") rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding as discussed in Section 2, Part C.

[2] 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.

Table 1 –
Summary of Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization – 2022

Line	Component	Description	OPG Proposed[3]	Settlement Adjustment	Settled Amount[4]
1	Rate Base	Net fixed assets, working capital, and cash working capital	$8,719.0M	$(29.2)M	$8,689.7M
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	$521.0M	$(28.2)M	$492.8M
3	OM&A	Operating, Maintenance, and Administration Expenses	$2,340.7M	$(64.5)M	$2,276.2M
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes, and Income Tax	$726.2M	$(2.4)M	$723.8M
5	Other Revenues	Bruce lease revenues and ancillary and other revenue	$21.4M	$(2.4)M	$19.0M
6	Stretch Factor	Cumulative stretch factor dollars	$0.0M	$0.0M	$0.0M
7	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	$3,609.3M	$(97.6)M	$3,511.7M
8	Amortization of Deferral & Variance Account Amounts (Nuclear)	Amortization of Deferral & Variance Accounts and other adjustments (Nuclear)	$77.6M	$(19.2)M	$58.4M
9	Amortization of Deferral & Variance Account Amounts (Hydroelectric)	Amortization of Deferral & Variance Accounts and other adjustments (Hydroelectric)	$43.7M	$(9.7)M	$34.0M
10	Production	Nuclear Production forecast	33.2TWh	0.4TWh	33.6TWh

[3] Per Draft PAO, Appendix A, Table 6.

[4] Per Draft PAO, Appendix A, Table 1.

Table 2 –
Summary of Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization – 2023

Line	Component	Description	OPG Proposed[5]	Settlement Adjustment	Settled Amount[6]
1	Rate Base	Net fixed assets, working capital, and cash working capital	$8,788.8M	$(87.4)M	$8,701.5M
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	$520.9M	$(31.8)M	$489.1M
3	OM&A	Operating, Maintenance, and Administration Expenses	$2,381.5M	$(66.5)M	$2,315.0M
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes, and Income Tax	$649.1M	$(5.0)M	$644.1M
5	Other Revenues	Bruce lease revenues and ancillary and other revenue	$(3.2)M	$(4.2)M	$(7.4)M
6	Stretch Factor	Cumulative stretch factor dollars	$(9.5)M	$(5.4)M	$(14.9)M
7	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	$3,538.8M	$(112.9)M	$3,425.9M
8	Amortization of Deferral & Variance Account Amounts (Nuclear)	Amortization of Deferral & Variance Accounts and other adjustments (Nuclear)	$77.6M	$(19.2)M	$58.4M
9	Amortization of Deferral & Variance Account Amounts (Hydroelectric)	Amortization of Deferral & Variance Accounts and other adjustments (Hydroelectric)	$43.7M	$(9.7)M	$34.0M
10	Production	Nuclear Production Forecast	30.8TWh	0.4TWh	31.2TWh

[5] Per Draft PAO, Appendix A, Table 6.

[6] Per Draft PAO, Appendix A, Table 2.

Table 3 –
Summary of Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization – 2024

Line	Component	Description	OPG Proposed[7]	Settlement Adjustment	Settled Amount[8]
1	Rate Base	Net fixed assets, working capital, and cash working capital	$11,262.4M	$(145.4)M	$11,116.9M
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	$674.7M	$(39.6)M	$635.1M
3	OM&A	Operating, Maintenance, and Administration Expenses	$2,206.3M	$(69.3)M	$2,137.0M
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes, and Income Tax	$783.9M	$(6.8)M	$777.0M
5	Other Revenues	Bruce lease revenues and ancillary and other revenue	$(4.2)M	$(5.2)M	$(9.4)M
6	Stretch Factor	Cumulative stretch factor dollars	$(18.6)M	$(10.6)M	$(29.2)M
7	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	$3,642.0M	$(131.5)M	$3,510.5M
8	Amortization of Deferral & Variance Account Amounts (Nuclear)	Amortization of Deferral & Variance Accounts and other adjustments (Nuclear)	$77.6M	$(19.2)M	$58.4M
9	Amortization of Deferral & Variance Account Amounts (Hydroelectric)	Amortization of Deferral & Variance Accounts and other adjustments (Hydroelectric)	$43.7M	$(9.7)M	$34.0M
10	Production	Nuclear Production Forecast	33.3TWh	0.7TWh	34.0TWh

[7] Per Draft PAO, Appendix A, Table 6.

[8] Per Draft PAO, Appendix A, Table 3.

Table 4 –
Summary of Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization – 2025

Line	Component	Description	OPG Proposed[9]	Settlement Adjustment	Settled Amount[10]
1	Rate Base	Net fixed assets, working capital, and cash working capital	$12,471.6M	$(202.1)M	$12,269.4M
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	$749.7M	$(44.8)M	$704.9M
3	OM&A	Operating, Maintenance, and Administration Expenses	$1,871.6M	$(68.4)M	$1,803.3M
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes, and Income Tax	$705.3M	$(8.1)M	$697.2M
5	Other Revenues	Bruce lease revenues and ancillary and other revenue	$24.7M	$(2.2)M	$22.5M
6	Stretch Factor	Cumulative stretch factor dollars	$(25.5)M	$(14.4)M	$(39.9)M
7	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	$3,325.8M	$(137.8)M	$3,188.0M
8	Amortization of Deferral & Variance Account Amounts (Nuclear)	Amortization of Deferral & Variance Accounts and other adjustments (Nuclear)	$166.2M	$(0.0)M	$166.2M
9	Amortization of Deferral & Variance Account Amounts (Hydroelectric)	Amortization of Deferral & Variance Accounts and other adjustments (Hydroelectric)	$22.8M	$0.0M	$22.8M
10	Production	Nuclear Production Forecast	30.2TWh	0.9TWh	31.1TWh

[9] Per Draft PAO, Appendix A, Table 6.

[10] Per Draft PAO, Appendix A, Table 4.

Table 5 –
Summary of Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Accounts - 2026

Line	Component	Description	OPG Proposed[11]	Settlement Adjustment	Settled Amount[12]
1	Rate Base	Net fixed assets, working capital, and cash working capital	$13,316.6M	$(247.2)M	$13,069.5M
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	$800.8M	$(48.9)M	$751.9M
3	OM&A	Operating, Maintenance, and Administration Expenses	$1,086.0M	$(47.1)M	$1,038.9M
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes, and Income Tax	$709.1M	$(11.9)M	$697.2M
5	Other Revenues	Bruce lease revenues and ancillary and other revenue	$(25.5)M	$(6.4)M	$(31.9)M
6	Stretch Factor	Cumulative stretch factor dollars	$(18.0)M	$(9.5)M	$(27.6)M
7	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	$2,552.4M	$(123.9)M	$2,428.5M
8	Amortization of Deferral & Variance Account Amounts (Nuclear)	Amortization of Deferral & Variance Accounts and other adjustments (Nuclear)	$166.2M	$(0.0)M	$166.2M
9	Amortization of Deferral & Variance Account Amounts (Hydroelectric)	Amortization of Deferral & Variance Accounts and other adjustments (Hydroelectric)	$22.8M	$0.0M	$22.8M
10	Production	Nuclear Production Forecast	21.5TWh	0.4TWh	21.9TWh

The impacts on nuclear payment amounts as a result of the Settlement Proposal, assuming OPG's proposed in-service additions for the D2O Project and reflecting OPG's updated rate smoothing proposal, which will be filed under separate cover, are identified

[11] Per Draft PAO, Appendix A, Table 6.

[12] Per Draft PAO, Appendix A, Table 5.

in Tables 6 and 7 below. The Parties note that the OEB's determinations on the partially settled and unsettled issues (including, but not limited to, rate smoothing) and the agreement to update the proposed ROE rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding may impact amounts set out in Tables 7, 8 and 8A.

Table 6 – OPG's Original Payment Amounts Proposal ($/MWh)

	2022	2023	2024	2025	2026
Smoothed Nuclear Payment Amount	$101.51	$105.13	$104.42	$106.70	$120.67
Nuclear Payment Amount Rider	$2.34	$2.52	$2.33	$5.50	$7.72
Total Nuclear Payments	$103.85	$107.65	$106.75	$112.20	$128.39
Hydroelectric Payment Amount	$43.88	$43.88	$43.88	$43.88	$43.88
Hydroelectric Payment Amount Rider	$1.33	$1.33	$1.33	$0.69	$0.69
Total Hydroelectric Payments	$45.21	$45.21	$45.21	$44.57	$44.57

Table 7 – Settlement Agreement Payment Amounts Proposal ($/MWh)

	2022	2023	2024	2025	2026
Smoothed Nuclear Payment Amount	$102.06	$105.68	$103.25	$102.54	$110.84
Nuclear Payment Amount Rider	$1.74	$1.87	$1.72	$5.34	$7.58
Total Nuclear Payments	$103.80	$107.55	$104.97	$107.88	$118.35
Hydroelectric Payment Amount	$43.88	$43.88	$43.88	$43.88	$43.88
Hydroelectric Payment Amount Rider	$1.03	$1.03	$1.03	$0.69	$0.69
Total Hydroelectric Payments	$44.91	$44.91	$44.91	$44.57	$44.57

The impacts on OPG's proposed rate smoothing deferral amounts as a result of the Settlement Proposal are identified in Table 8 below.

Table 8 – OPG Proposed Rate Smoothing Deferral Amounts ($M)

	2022	2023	2024	2025	2026
OPG's Original Proposal	$241.2	$299.9	$167.0	$103.4	$(44.8)
OPG's Updated Proposal	$82.4	$125.7	$0.0	$0.0	$0.0
Difference	$(158.8)	$(174.2)	$(167.0)	$(103.4)	$44.8

The above information on OPG's revised rate smoothing proposal is being provided for illustrative purposes only in order to provide context, as the issue remains unsettled. OPG's revised rate smoothing proposal, which incorporates OPG's disputed proposal for recovery of D2O Project costs, will be filed under separate cover as it provides the necessary context for the changes to the smoothed nuclear payment amounts presented in the Settlement Proposal. As noted, the Parties agree to defer the consideration of rate

smoothing to the process of establishing the final payment amounts order arising from the OEB's decision on this Settlement Proposal and the remaining issues to be considered by the OEB in the pending hearing.

The impacts on the estimated residential customer bill impacts reflecting the Settlement Proposal, OPG's revised rate smoothing proposal and OPG's proposed in-service additions for the D2O Project are provided in Table 8A below.

Table 8A – OPG Revised Customer Bill Impacts ($/Month)

	2022	2023	2024	2025	2026	Average
OPG's Original Proposal	$1.04	$0.26	$0.27	$0.26	$0.23	$0.41
OPG's Updated Proposal	$1.04	$0.26	$0.01	$(0.04)	$(0.37)	$0.18
Difference	$0.00	$0.00	$(0.26)	$(0.30)	$(0.60)	$(0.23)

This settlement proposal represents an overall reduction in revenue requirement of $603.7M over the 5-year rate period. Contributing to this overall reduction in revenue requirement is a decrease in requested OM&A costs of $315.8M over the period and a reduction in rate base of $247.2M by 2026. In addition to and in consideration of the settlement, the Parties agree that a portion of the nuclear net plant rate base amount (based on in-service capital additions of $358.0M) will be subject to a return on equity equivalent to the OEB-approved long-term debt cost rate for OPG over the period from January 1, 2022 to December 31, 2036. Beginning in 2037, the remaining undepreciated portion of these in-service capital additions will earn a return on equity at the OEB-approved ROE rate in place at that time. The time period over which this approach will apply, as a mitigating measure, coincides with the expected end of the rate smoothing recovery period under O.Reg 53/05, s. 6(2)12.

Over the same 5-year period, the Settlement Proposal reflects a total increase in forecast nuclear production of 2.8TWh.

With respect to the rate framework, the Parties have agreed to expand the scope of costs to which the nuclear stretch factor applies, an increase in the nuclear stretch factor and an earnings sharing mechanism. The cumulative impact on the revenue requirement net of stretch factor from changes to the rate framework is a reduction of approximately $40M.

The Parties agree that OPG will recover all deferral and variance account balances as proposed, subject to the OEB's decision on the D2O Project and except for a $40M portion of the recorded debit balance of the Hydroelectric Surplus Baseload Generation Variance Account, the clearance of which is deferred until a later proceeding addressing changes to the Hydroelectric Incentive Mechanism and impacts from the Independent Electricity System Operator's Market Renewal Program (the "**MRP**").

Incremental to revenue requirement and the recovery of deferral and variance accounts, OPG will credit ratepayers with $46.6M, representing the net difference between OPG's favourable generation margin impact and the incremental OM&A net of savings related to OPG's response to the COVID-19 pandemic.

This Settlement Proposal is the culmination of extensive discussion and consideration by the Parties which represent an array of interests affected by OPG's application for payment amounts. Based on the impacts of the settlement described above, together with the evidence and rationale provided below, the Parties agree that this Settlement Proposal is in the public interest and the Parties recommend its acceptance by the OEB. OPG has prepared a draft Payment Amounts Order reflecting the settlement and has attached the same at Appendix B.

SECTION 2 - KEY COMPONENTS OF SETTLEMENT

The subsections below summarize the key components of the settlement reached by the Parties. The evidentiary basis upon which each specific issue was settled is summarized in Section 3 below.

Table 9 – 2022-2026 Settled Revenue Requirement ($M)[13]

	2022	2023	2024	2025	2026
OPG's Proposed Revenue Requirement Net of Stretch Factor	$3,609.3	$3,538.8	$3,642.0	$3,325.8	$2,552.4
Settled Revenue Requirement Net of Stretch Factor	$3,511.7	$3,425.9	$3,510.5	$3,188.0	$2,428.5
Difference	$(97.6)	$(112.9)	$(131.5)	$(137.8)	$(123.9)

A. Rate Framework

The Parties agree to the application of OPG's proposed rate framework for the five-year IR term from 2022 to 2026, including a nuclear stretch factor applicable for years 2023 to 2026 and an adjustment to the stretch factor in 2026 to reflect the closure of the Pickering station, with some modifications. In addition, the Parties agree to the establishment of an earnings sharing mechanism.

The modifications to the proposed rate framework arising from the settlement are outlined in Table 10 below.

[13] Subject to any adjustments for the OEB's decision on the D2O Project and the agreement to update the proposed ROE rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Table 10 – Modifications to Proposed Rate Framework

	OPG's Original Proposal	Settlement Proposal
Stretch Factor Scope	• OM&A (Base, Project, Outage, and Allocated Corporate Support OM&A) • Nuclear Operations and Support Services In-Service Additions Revenue Requirement	• OM&A (Base, Project, Outage, and Allocated Corporate Support OM&A, and Asset Service Fees) • Full Capital-Related Revenue Requirement Excluding the Darlington Refurbishment Program ("DRP")[14]
Stretch Factor	• 0.45% for 2023-2025 • 0.30% for 2026	• 0.60% for 2023-2025 • 0.30% for 2026
Earning Sharing Mechanism ("ESM")	• None	• Earnings sharing mechanism based on the performance of the combined nuclear and regulated hydroelectric business on an asymmetrical basis, with a 100-basis point deadband to the OEB-approved ROE rate and 50/50 sharing above the deadband, assessed over a cumulative 5-year period from 2022-2026 • The OEB approved ROE rate for the 5-year period will be the rate base-weighted average of the OEB approved ROE rate from EB-2013-0321 for the regulated hydroelectric facilities and from EB-2020-0290 for the nuclear facilities, and the achieved ROE for the combined nuclear and regulated hydroelectric business shall be calculated consistent with OPG's annual reporting requirements related to actual annual regulatory return as set out in Appendix A.[15] • Any such amount to be recorded in an Earnings Sharing Deferral Account for disposition following the 5-year period

The annual Stretch Factor reduction to nuclear revenue requirement based on the settlement is set out in Table 11 below.

Table 11 – 2023-2026 Settled Stretch Factor Reduction Amounts ($M)

	2023	2024	2025	2026
OPG's Proposed Stretch Reduction to Revenue Requirement[16]	$9.5	$18.6	$25.5	$18.0
Settled Stretch Reduction to Revenue Requirement[17,18]	$14.9	$29.2	$39.9	$27.6

Additionally, and in contemplation of the MRP, the Parties agree that OPG shall file an application with the OEB regarding any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP with sufficient time for the OEB to adjudicate the application prior to the scheduled implementation of the MRP. The Parties acknowledge that in conjunction with that application, or separately during the IR term, OPG may also file an application to clear deferral and variance accounts.[19]

B. Impact of COVID-19 Pandemic

The Parties agree that, incremental to the revenue requirement and proposed recovery of deferral and variance accounts, OPG will credit ratepayers with $46.6M, representing the net difference between OPG's favourable generation margin impact ($80.9M[20]) and the incremental OM&A costs net of savings ($34.3M[21]) related to the company's response to the COVID-19 pandemic in 2020 (actual) and 2021 (forecast). These amounts encompass impacts for both regulated hydroelectric and nuclear operations. OPG's original proposal was to not seek recovery of the incremental OM&A costs net of savings, nor credit ratepayers with the favourable generation margin impact.[22] The Parties agree that the $46.6M net credit amount shall not be subject to update for actual results in 2021.

The disposition of the incremental $46.6M net credit amount over a three-year period is included as an adjustment in the calculation of the 2022-2024 nuclear and hydroelectric

[14] Unless otherwise noted, references to DRP in this document include the D2O Project.
[15] For the five-year period, the OEB-approved ROE rate for the hydroelectric facilities shall be the 9.33% ROE rate approved in EB-2013-0321 (being the average of the 2014 ROE rate of 9.30% and the 2015 ROE rate of 9.36%) and, for the nuclear facilities, the ROE rate to be approved in EB-2020-0290 as set out in this Settlement Proposal.
[16] Draft PAO Appendix A, Table 6, line 25.
[17] Subject to the agreement to update the proposed ROE rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding.
[18] Draft PAO Appendix A, Table 7, line 25.
[19] Ex. L-A1-01-Staff-010.
[20] Ex. L-A2-02-CCC-013, Attachment 1, Table 1, line 7: col. (c) plus col. (f).
[21] Ex. L-A2-02-CCC-013, Attachment 1, Table 1, line 10: col. (c) plus col. (f). These amounts are being recorded by OPG in the Impacts Arising from the COVID-19 Emergency Deferral Account.
[22] Ex. JT2.34.

payment riders, as shown in the Draft Payment Amounts Order, Appendix C, Table 1, line 20 and Appendix D, Table 1, line 29.

The Parties also agree to the termination of the Impacts Arising from the COVID-19 Emergency Deferral Account for OPG effective as of the date the OEB approves this Settlement Proposal.

Additionally, the Parties agree that it is appropriate for OPG to record COVID-19 related costs for CRVA-eligible activities in the CRVA, in accordance with O. Reg. 53/05, s. 6(2)4. Recovery of any recorded amounts will be subject to a prudence review when OPG seeks disposition of any such balances.

C. Rate Base and Cost of Capital

(i) Rate Base

The Parties agree to the opening 2022 rate base values for nuclear facilities as proposed by OPG, other than for the D2O Project. The Parties further agree to the forecast rate base for nuclear facilities for 2022-2026 set out in Table 12 below, subject to the OEB's decision on the proposed in-service additions for the D2O Project. The reduction in settled rate base relative to OPG's request relates to agreed-upon adjustments to the proposed 2022-2026 forecasted in-service additions for Nuclear Operations and Corporate Support Services, discussed below.

Table 12 – 2022-2026 Settled Rate Base ($M)[23]

	2022	2023	2024	2025	2026
OPG's Proposed Rate Base	$8,719.0	$8,788.8	$11,262.4	$12,471.6	$13,316.6
Settled Rate Base	$8,689.7	$8,701.5	$11,116.9	$12,269.4	$13,069.5
Difference	$(29.2)	$(87.4)	$(145.4)	$(202.1)	$(247.2)

OPG's proposed forecast in-service capital additions for 2022-2026 are set out in Table 13 below.

[23] Subject to any adjustments for the OEB's decision on the D2O Project.

Table 13 – OPG Proposed Forecast In-service Capital Additions ($M)[24]

	Reference	2022	2023	2024	2025	2026
Nuclear Operations capital projects	Ex. D2-1-3 Table 4b, lines 14 & 26	$434.3	$461.6	$489.0	$477.3	$348.3
Darlington Refurbishment Program	Ex. D2-2-9 Table 5b, lines 33 & 46	$0	$1.4	$2,505.5	$1,907.3	$2,028.3
Support Services capital projects entering nuclear rate base	Ex. D3-1-2 Table 5b; lines 17, 19, 25 & 27	$68.3	$38.0	$34.4	$47.8	$30.9
Total nuclear in-service additions	Ex. B3-3-1 Table 2, col. (b)	**$502.6**	**$501.0**	**$3,028.9**	**$2,432.5**	**$2,407.5**

The Parties agree that forecasted nuclear capital expenditures and financial commitments and in-service additions for the DRP are reasonable and appropriate and form part of the settled forecast rate base for the 2022-2026 period on the basis that they remain within the total $12.8B project budget first set out in EB-2016-0152. The OEB will review the prudence of any amounts sought by OPG in excess of the $12.8B total, the appropriateness of any future material changes to the scope of the DRP and any corresponding changes in contracts, when OPG seeks disposition of the actual DRP costs through the Capacity Refurbishment Variance Account.

With respect to the Nuclear Operations projects, the Parties agree to reduce the forecast in-service additions by 13% per year for the 2022-2026 period. The Parties further agree to reduce the forecast in-service additions for Corporate Support Services by 5% per year for the 2022-2026 period. The adjustments associated with these reductions are set out in Table 14 below.

[24] Amounts may not add due to rounding.

Table 14 – Settlement Adjustments to Forecast In-service Capital Additions ($M)[25]

	Reference	2022	2023	2024	2025	2026
Nuclear Operations capital projects	13% of Ex. D2-1-3 Table 4b, lines 14 & 26	$(56.5)	$(60.0)	$(63.6)	$(62.1)	$(45.3)
Support Services capital projects entering nuclear rate base	5% of Ex. D3-1-2 Table 5b, lines 17, 19, 25 & 27	$(3.4)	$(1.9)	$(1.7)	$(2.4)	$(1.5)
Total settlement adjustment to nuclear in-service additions		**$(59.9)**	**$(61.9)**	**$(65.3)**	**$(64.4)**	**$(46.8)**

The settled forecasted in-service capital additions for 2022-2026 are set out in Table 15 below.

Table 15 – Settled Forecast In-service Capital Additions ($M)[26]

	Reference	2022	2023	2024	2025	2026
Nuclear Operations capital projects	Ex. D2-1-3 Table 4b, lines 14 & 26, less 13%	$377.8	$401.6	$425.4	$415.2	$303.0
Darlington Refurbishment Program	Ex. D2-2-9 Table 5b, lines 33 & 46	$0	$1.4	$2,505.5	$1,907.3	$2,028.3
Support Services capital projects entering nuclear rate base	Ex. D3-1-2 Table 5b; lines 17, 19, 25 & 27, less 5%	$64.9	$36.1	$32.7	$45.4	$29.4
Total nuclear in-service additions, excluding ARC		**$442.7**	**$439.1**	**$2,963.6**	**$2,368.0**	**$2,360.7**

[25] Amounts may not add due to rounding.
[26] Amounts may not add due to rounding.

For purposes of settlement, the Parties agree that, for a portion of the nuclear net plant rate base amount, the return on equity will be set equivalent to the OEB-approved long-term debt cost rate for OPG, rather than the OEB-approved ROE rate and that this treatment shall apply over the period from January 1, 2022 to December 31, 2036, being the expected end of the rate smoothing recovery period under O. Reg. 53/05, s. 6(2)12. The affected nuclear net plant rate base amount is the remaining undepreciated portion, at that time, of OPG's 2017-2021 in-service capital additions totaling $358.0M, as summarized in Table 15A below. This represents: a) 100% of the difference between OPG's actual/EB-2020-0290 planned in-service capital additions, and such forecasted amounts in EB-2016-0152, between 2017 and 2021, and b) 50% of the difference between the forecasted and OEB-approved in-service capital additions in EB-2016-0152, between 2017 and 2021. The derivation of this amount and its undepreciated portion over the 2022-2026 period is included in the Draft Payment Amounts Order, Appendix A, Table 16. Beginning in 2037, the remaining undepreciated portion of these in-service capital additions will earn a return on equity at the OEB-approved ROE rate in place at that time. The revenue requirement impact of this element of the settlement is included in section (ii), Capital Structure.

Table 15A – 2017-2021 In-Service Capital Additions Subject to Return on Equity Equivalent to Long Term Debt Rate ($M)

		2017	2018	2019	2020	2021	Total
EB-2020-0290 Proposed In-service Capital Additions excl. DRP[27]	A	$472.3	$423.6	$368.1	$326.1	$390.6	$1,980.8
EB-2016-0152 Forecasted In-service Capital Additions excl. DRP[28]	B	$508.8	$372.1	$393.0	$249.4	$184.8	$1,708.2
EB-2016-0152 OEB Approved In-service Capital Additions excl. DRP[29]	C	$457.9	$334.9	$353.7	$224.4	$166.3	$1,537.3
Total nuclear in-service additions subject to return on equity equivalent to long-term debt rate	**A – B + 50% x (B – C)**	**$(11.0)**	**$70.0**	**$(5.1)**	**$89.2**	**$215.0**	**$358.0**

(ii) Cost of Capital and Capital Structure

The Parties agree for the capital structure to remain unchanged from EB-2016-0152 at 45% equity and 55% debt for the purposes of determining the nuclear revenue requirements for the 2022-2026 period. OPG had proposed a capital structure of 50% equity and 50% debt in its application.[30]

The Parties also agree to set the OEB-approved ROE rate[31], long-term cost of debt rate and short-term cost of debt rate[32] for the 2022-2026 period as proposed by OPG.

Based on the above parameters and subject to the OEB's decision on the D2O Project, Table 16 below sets out the settled nuclear cost of capital amounts for the 2022-2026

[27] Ex. B3-3-1, Table 1, col. (b), Darlington NGS + Pickering NGS + Operations and Project Support.
[28] EB 2016-0152 Ex. J21.1, Attachment 2, Table 1, Nuclear Operations capital projects + Support Services capital projects entering rate base.
[29] EB-2016-0152 PAO, App. A, Table 9, col. (b), Darlington NGS + Pickering NGS + Nuclear Support Divisions + Forecast In-Service Additions Reduction.
[30] Ex. C1-1-1.
[31] As proposed by OPG in Ex. C1-1-1, the Parties agree that the ROE rate for the 2022-2026 period shall be established using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report as of the effective date of the final payment amounts order in this proceeding.
[32] Ex. C1-1-2 and Ex. C1-1-3.

period, inclusive of the rate base portion for which the Parties agree to set return on equity equivalent to OPG's OEB-approved long-term cost of debt rate.

Table 16 – 2022-2026 Settled Cost of Capital ($M)[33]

	2022	2023	2024	2025	2026
OPG's Proposed Cost of Capital	$521.0	$520.9	$674.7	$749.7	$800.8
Settled Cost of Capital	$492.8	$489.1	$635.1	$704.9	$751.9
Difference	$(28.2)	$(31.8)	$(39.6)	$(44.8)	$(48.9)

D. Production Forecast

The Parties agree to a modified 2022-2026 nuclear production forecast from OPG's original proposal, as set out in Table 17 below.

Table 17 – 2022-2026 Settled Production Forecast (TWh)

	2022	2023	2024	2025	2026
OPG's Proposed Nuclear Production Forecast	33.2	30.8	33.3	30.2	21.5
Settled Nuclear Production Forecast	33.6	31.2	34.0	31.1	21.9
Difference	0.4	0.4	0.7	0.9	0.4

E. Operating Costs

(i) OM&A Expenses

The Parties agree to reduce the proposed total OM&A expenses for the nuclear facilities, excluding Darlington Refurbishment OM&A, Darlington New Nuclear OM&A and Centrally Held Costs, but including Asset Service Fees, for each year of the 2022-2026 period by 3.0%. The Parties agree to Darlington Refurbishment OM&A, Darlington New Nuclear OM&A and Centrally-Held Costs as proposed by OPG.

In addition, the Parties agree to exclude OPG's planned new corporate head office (to be located in Clarington, the "**Clarington Corporate Campus**") from the Asset Service Fees included in the revenue requirements for the IR term. The Parties agree that OPG will establish a Clarington Corporate Campus Deferral Account to record the revenue requirement impact of the capital expenditures and operating costs for the Clarington Corporate Campus, calculated on the same basis as OPG's existing Asset Service Fee methodology. Settlement with respect to this aspect is without prejudice to any position that a Party may take with respect to the appropriateness of cost recovery of the Clarington Corporate Campus project capital costs. Parties agree that these matters will be addressed when OPG seeks to dispose of the deferral account. OPG's evidence forecasts the project to be placed in service beginning in 2024.

[33] Subject to any adjustments for the OEB's decision on the D2O project and the agreement to update the proposed ROE rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

The OM&A expenses have also been adjusted for the impact of the agreed-upon capital structure on the remaining Asset Service Fees for the 2022-2026 period.

The settled total OM&A expenses are set out in Table 18 below.

Table 18 – 2022-2026 Settled Total OM&A Expenses ($M)

	2022	2023	2024	2025	2026
OPG's Proposed Total OM&A	$2,340.7	$2,381.5	$2,206.3	$1,871.6	$1,086.0
Settled Total OM&A[34]	$2,276.2	$2,315.0	$2,137.0	$1,803.3	$1,038.9
Difference	$(64.5)	$(66.5)	$(69.3)	$(68.4)	$(47.1)

(ii) Fuel Costs

Nuclear fuel costs consist of the following:

- The weighted average cost of manufactured uranium fuel bundles loaded into a reactor ("**nuclear fuel bundle cost**").
- Used nuclear fuel storage and disposal.
- Fuel oil used to run stand-by generators at OPG's nuclear stations.

The Parties agree to reduce nuclear fuel bundle costs by 2% for each year of the 2022-2026 IR term. The settled nuclear fuel costs also include the flow through impacts of the production forecast adjustments identified above. The Parties agree to the remaining components of fuel costs as proposed by OPG. The settled nuclear fuel costs are set out in Table 19 below.

Table 19 – 2022-2026 Settled Fuel Costs ($M)

	2022	2023	2024	2025	2026
OPG's Proposed Nuclear Fuel Costs	$178.3	$182.1	$209.4	$188.6	$148.2
Settled Nuclear Fuel costs	$177.3	$181.2	$209.5	$189.9	$148.0
Difference	$(1.0)	$(0.9)	$0.1	$1.3	$(0.2)

[34] Due to the impact on asset service fees, subject to the agreement to update the proposed ROE rate for the 2022-2026 period using the prevailing ROE specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

(iii) Depreciation and Amortization

Subject to the adjustments made in connection with modifications to the forecasted capital in-service additions and pending the OEB's decision on the D2O Project, the Parties agree that the proposed nuclear depreciation and amortization expense for the IR term is appropriate. The settled depreciation and amortization expense is set out in Table 20 below.

Table 20 – 2022-2026 Settled Depreciation and Amortization Expense ($M)

	2022	2023	2024	2025	2026
OPG's Proposed Depreciation	$551.5	$470.0	$577.2	$520.1	$567.1
Settled Nuclear Depreciation[35]	$550.1	$465.9	$570.3	$510.8	$555.3
Difference	$(1.4)	$(4.1)	$(6.9)	$(9.4)	$(11.8)

(iv) Income and Property Taxes

Subject to the adjustments in connection with modifications to the forecasted capital in-service additions and pending the OEB's decision on the D2O Project, the Parties agree that the proposed income tax and property tax amounts for the IR term are appropriate.

F. Other Revenues

The Parties agree to increase, by 10%, OPG's proposed annual forecast of nuclear non-energy revenues (net of related costs) for the 2022-2026 period. The Parties agree that OPG's forecast revenue related to the Bruce lease and costs related to the Bruce nuclear generating stations for the 2022-2026 period are appropriate. The settled Other Revenues are set out in Table 21 below.

[35] Subject to any adjustments for the OEB's decision on the D2O project.

Table 21 – 2022-2026 Settled Other Revenues ($M)

	2022	2023	2024	2025	2026
OPG's Proposed Nuclear Other Revenues	$24.2	$41.9	$52.3	$21.8	$63.8
Settled Nuclear Other Revenues	$26.6	$46.1	$57.5	$24.0	$70.2
Difference	$2.4	$4.2	$5.2	$2.2	$6.4

G. Deferral and Variance Accounts

OPG proposed to clear the audited balances in all deferral and variance accounts as at December 31, 2019, less amortization amounts previously approved by the OEB in EB-2018-0243 and EB-2016-0152, with certain exceptions.[36] Adjusted for previously approved 2020-2021 amortization amounts and together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the proposed balances recoverable were a net debit balance of $176.8M for the regulated hydroelectric facilities and a net debit balance of $565.2M for the nuclear facilities.[37] OPG proposed to recover balances in the majority of accounts over January 1, 2022 to December 31, 2024, with certain components of the Pension & OPEB Cash Versus Accrual Differential Deferral Account recovered over January 1, 2022 to December 31, 2026.

Subject to the OEB's decision on the D2O Project, the Parties agree that OPG shall recover all balances as proposed, with the exception of a $40.0M portion of the debit balances recorded in the Hydroelectric Surplus Baseload Generation Variance Account. The clearance of this $40.0M amount is deferred until the proceeding addressing any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP. OPG originally sought recovery of debit entries in the account totaling $191.3M (plus interest) recorded over 2018 and 2019. The Parties also agree upon certain reporting and other requirements going forward for clearing this account, as set out in Section 3 below and in Appendix A.

The Parties agree to continue existing deferral and variance accounts using the methodologies that have been used to record entries into these accounts to date as

[36] OPG proposed to defer clearance of the following: the DRP and hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA"), the Fitness for Duty Deferral Account, the portion of the Nuclear Development Variance Account related to preliminary planning and preparation costs incurred for a SMR generating station at the Darlington site, and the Rate Smoothing Deferral Account.

[37] Details regarding proposed account clearance and riders are presented in Ex. H1-2-1. The audited balances in each of the deferral and variance accounts are shown in Ex. H1-1-1, Table 1.

approved by the OEB, as proposed by OPG.[38] This includes maintaining the Pension and OPEB Cost Variance Account for nuclear facilities to resume recording of variances between: (i) pension and OPEB accrual costs, plus related income tax PILs, reflected in the current revenue requirement and; (ii) OPG's actual pension and OPEB accrual costs, and associated income tax impacts. No further additions will be recorded in the Pension & OPEB Cash Payment Variance Account as well as the Pension & OPEB Cash Versus Accrual Differential Deferral Account, as of January 1, 2022, for nuclear facilities as the nuclear revenue requirements in this proceeding reflect pension and OPEB costs calculated on an accrual basis. The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account for nuclear facilities will continue to operate as detailed in Appendix E to the Draft Payment Amounts Order. The Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account will record only interest and amortization, as applicable, for nuclear facilities.[39]

For hydroelectric facilities, the Pension and OPEB Cost Variance Account will continue to record only amortization, as applicable. The Pension & OPEB Cash Payment Variance Account as well as the Pension & OPEB Cash Versus Accrual Differential Deferral Account will continue to operate as in the previous payment amount period until OPG rebases hydroelectric payment amounts. The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account will continue to operate as detailed in Appendix E to the Draft Payment Amounts Order.[40]

The Parties also agree that OPG will establish the following new accounts, effective January 1, 2022:

- **Impact for IFRS Deferral Account** – an account 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). For greater clarity, such account would include, but not be limited to, unamortized gains/losses and past service costs/credits balances recorded for pension and OPEB plans in accumulated other comprehensive income/loss under US GAAP, as attributed to regulated operations. The account will be effective until the effective date of OPG's next cost based payment amounts order.
- **Clarington Corporate Campus Deferral Account** – an account 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 this proceeding.
- **Earnings Sharing Deferral Account** – an account to record any earnings for the combined nuclear and regulated hydroelectric business on an asymmetrical basis

[38] Ex. H1-1-1.
[39] Ex. H1-1-1, pp. 23-29.
[40] *Ibid*.

that exceed a 100 basis point deadband to the OEB-approved ROE rate, assessed over a cumulative 5-year period from 2022-2026.

- **Sale of Unprescribed Kipling Site Deferral Account** – an account to record 23% of the net proceeds arising from any sale of OPG's unprescribed site located at 800 Kipling Avenue in Toronto during the IR term, which is the portion of the site attributable to OPG's regulated business. The recording of this amount is without prejudice to any position a Party may take as to whether any portion of this amount should be returned to ratepayers at the time of the account's disposition.

The Parties also agree to OPG's proposed establishment of the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, effective January 1, 2021.[41]

H. Reporting and Record Keeping Requirements

The Parties agree to the reporting and record keeping requirements for OPG as set out in Appendix A hereto. The Parties also agree that OPG will undertake certain independent studies, reports, and other filings as set out in Appendix A hereto.

I. Rate Smoothing

The Parties agree that OPG's rate smoothing proposal for nuclear payment amounts shall be considered as part of establishing the final payment amounts order following the OEB's decision and order on this Settlement Proposal and the remaining issues to be considered by the OEB in the pending hearing.

J. Implementation

The Parties agree that the effective date for new payment amounts and riders shall be January 1, 2022.

[41] 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 OPG's 2022-2026 payment amounts proceeding.

SECTION 3 - SETTLEMENT BY ISSUE

GENERAL

Issue 1.1 Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

Complete Settlement

The Parties agree that OPG has responded appropriately to all relevant OEB directions from previous proceedings.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, OSEA, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-11-1 (Summary of OEB Directives and Undertakings from Previous Proceedings)
Interrogatories	None
Undertakings	None

Issue 1.2 How could OPG further improve its customer engagement process?

Partially Settled

The Parties accept OPG's customer engagement process, with the only exception being as it relates to SMRs.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-11-1 (Summary of OEB Directives and Undertakings from Previous Proceedings), Ex. A2-2-1 (Business Planning and Budgeting; See Section 6), Ex. D2-1-3 (Capital Projects – Nuclear Operations; See Section 3.5), Ex. I1-3-2 (Payment Amount Smoothing)
Interrogatories	Ex. L-A2-02-Staff-021, Ex. L-A2-02-Staff-022, Ex. L-A2-02-Staff-023, Ex. L-I1-03-Staff-345, Ex. L-A2-02-CCC-019, Ex. L-A2-02-CCC-020, Ex. L-A2-02-CME-005, Ex. L-A2-02-Energy Probe-004, Ex. L-A1-03-SEC-005, Ex. L-A2-02-SEC-014
Undertakings	None

RATE FRAMEWORK

Issue 2.1 Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Complete Settlement

The Parties accept OPG's proposed rate framework to the five-year IR term from 2022 to 2026, including a nuclear stretch factor applicable for years 2023 to 2026 and an adjustment to the stretch factor in 2026 to account for the closure of the Pickering station, with the modifications as set out in Section 2, Part A above. In particular, the nuclear stretch factor that would apply is 0.6% for 2023-2025 and 0.3% for 2026. The stretch factor will apply to the cost categories set out in OPG's evidence (see Ex. A1-3-2, p. 12), with the addition of Asset Service Fees and subject to the inclusion of the entire capital-related revenue requirement, excluding the DRP.

Additionally, and in contemplation of the MRP, the Parties agree that OPG shall file an application with the OEB regarding any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP with sufficient time for the OEB to adjudicate the application prior to the scheduled implementation of the MRP.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-3-1 (Summary of Application), Ex. A1-11-1 (Summary of OEB Directives and Undertakings from Previous

	Proceedings), Ex. A1-3-2 (Nuclear Rate-setting Framework and Performance Reporting), Ex. A2-2-1 (Business Planning and Budgeting), Ex. A2-3-1 (Rating Agency Reports), Ex. I1-1-1 (Summary of Revenue Requirement and Revenue Deficiency), Ex. I1-3-1 (Payment Amount Smoothing)
Interrogatories	Ex. L-A1-03-Staff-003, Ex. L-A1-03-Staff-004, Ex. L-A1-03-Staff-009, Ex. L-A1-03-Staff-005, Ex. L-A1-03-Staff-006, Ex. L-A1-03-CME-011, Ex. L-A1-03-Energy Probe-003, Ex. L-F2-01-Energy Probe-053, Ex. L-A1-03-PWU-012, Ex. L-A1-03-SEC-007, Ex. L-I1-01-VECC-037
Undertakings	None

Issue 2.2 Is it appropriate to establish an earnings sharing mechanism or similar type of mechanism for the 2022 to 2026 period?

Complete Settlement

The Parties agree to an ESM based on the performance of the combined nuclear and regulated hydroelectric business on an asymmetrical basis, with a 100 basis point deadband to the OEB-approved ROE rate and 50/50 sharing above the deadband, assessed over a cumulative 5-year period from 2022-2026. Any such amount will be recorded in the Earnings Sharing Deferral Account.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	None
Interrogatories	Ex. L-A1-03-Staff-008
Undertakings	None

Issue 3.1 Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Complete Settlement

Taking into account the modifications to OPG's proposals regarding forecast cost and production levels as set out in this Settlement Proposal, the Parties accept the nuclear benchmarking methodology, results and targets as reasonable.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-3-2 (Nuclear Rate-setting Framework and Performance Reporting), Ex. A1-11-1 (Summary of OEB Directives and Undertakings from Previous Proceedings), Ex. F2-1-1 (Business Planning and Benchmarking – Nuclear)
Interrogatories	Ex. L-A1-02-CME-006, Ex. L-A1-03-Staff-004, Ex. L-A1-03-Staff-005, Ex. L-F2-01-Staff-193, Ex. L-F2-01-Staff-194, Ex. L-F2-01-Staff-195, Ex. L-F2-01-Staff-196, Ex. L-F2-01-Staff-197, Ex. L-F2-01-Staff-198, Ex. L-F2-01-Staff-199, Ex. L-F2-01-Staff-200, Ex. L-F2-01-Staff-201, Ex. L-F2-01-Staff-202, Ex. L-F2-01-Staff-203, Ex. L-F2-01-Staff-204, Ex. L-F2-01-Staff-205, Ex. L-F2-01-Staff-206, Ex. L-F2-01-Staff-207, Ex. L-F2-01-Staff-214, Ex. L-F2-01-Staff-215, Ex. L-F2-01-Staff-216, Ex. L-F2-01-Staff-217, Ex. L-F2-01-Staff-218, Ex. L-F2-01-Staff-219, Ex. L-F2-01-Staff-220, Ex. L-F2-01-Staff-221, Ex. L-F2-01-Staff-222, Ex. L-F2-01-Staff-223, Ex. L-F2-01-Energy Probe-053, Ex. L-F2-01-Energy Probe-054, Ex. L-F2-01-CME-014, Ex. L-F2-01-CME-015, Ex. L-F2-01-CME-016, Ex. L-F2-01-CME-017, Ex. L-F2-01-PWU-013, Ex. L-F2-01-PWU-014, Ex. L-F2-01-PWU-019, Ex. L-F2-01-PWU-022, Ex. L-F2-01-PWU-027, Ex. L-F2-01-PWU-028, Ex. L-F2-01-SEC-121, Ex. L-F2-01-SEC-122, Ex. L-F2-01-SEC-123, Ex. L-F2-01-SEC-124, Ex. L-F2-01-Society-014
Undertakings	JT1.15, JT1.16, JT1.17, JT1.24, JT1.26, JT1.27, JT1.28, JT3.21, JT4.13

IMPACT OF COVID-19 PANDEMIC

Issue 4.1 Is OPG's proposed ratemaking treatment of the COVID-19 pandemic-related impacts appropriate?

Complete Settlement

The Parties agree that OPG will credit ratepayers with $46.6M, representing the net difference between OPG's favourable generation margin ($80.9M) and the incremental OM&A costs net of savings ($34.3M) related to the company's response to the COVID-19 pandemic over 2020 and 2021. These amounts encompass pandemic impacts for both regulated hydroelectric and nuclear operations.

The Parties also agree to the termination of the Impacts Arising from the COVID-19 Emergency Deferral Account for OPG effective on the OEB's approval of this Settlement Proposal.

Additionally, the Parties agree that it is appropriate for OPG to record COVID-19 related costs for CRVA-eligible activities in the CRVA, in accordance with O. Reg. 53/05, s. 6(2)4. Recovery of any recorded amounts will be subject to a prudence review when OPG seeks disposition of any such balances.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-3-1 (Summary of Application), Ex. A2-1-1 (Financial Summary), Ex. A2-2-1 (Business Planning and Budgeting)
Interrogatories	Ex. L-A1-03-Staff-018, Ex. L-A1-03-Staff-019, Ex. L-E2-01-Staff-187, Ex. L-F3-01-Staff-250, Ex. L-A2-02-CCC-013, Ex. L-D2-02-Energy Probe-019, Ex. L-H1-01-LPMA-016, Ex. L-D2-02-SEC-079, Ex. L-E2-01-SEC-114
Undertakings	JT1.21, JT2.34, JT2.37, JT3.5, JI1.1, JI1.2

RATE BASE

Issue 5.1 Are the amounts proposed for nuclear rate base appropriate?

Complete Settlement

With the exception of the D2O Project, the Parties agree to OPG's proposed 2022 opening rate base and forecast rate base for the period 2022-2026, subject to adjustments to the forecast in-service capital additions as described in greater detail in Section 2, Part C above.

For purposes of settlement, the Parties agree that, for a portion of the nuclear net plant rate base amount, the return on equity will be equivalent to the OEB-approved long-term debt cost rate for OPG over the period from January 1, 2022, to December 31, 2036, being the expected end of the rate smoothing recovery period under O. Reg. 53/05, s. 6(2)12. The affected nuclear net plant rate base amount shall be the remaining undepreciated portion, at that time, of OPG's 2017-2021 nuclear in-service capital additions totaling $358.0M. This represents: a) 100% of the difference between OPG's actual/EB-2020-0290 planned in-service capital additions, and such forecasted amounts in EB-2016-0152, between 2017 and 2021, and b) 50% of the difference between the forecasted and OEB-approved in-service capital additions in EB-2016-0152, between 2017 and 2021. Beginning in 2037, the remaining undepreciated amount will earn a return on equity at the OEB-approved ROE rate, in place at that time.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. B1-1-1 (Rate Base), Ex. D2-1-3 (Capital Projects – Nuclear), Ex. D2-2-1 (Darlington Refurbishment Program), Ex. D2-2-10 (D2O Storage Project), Ex. D3-1-2 (Capital Projects – Support Services)
Interrogatories	Ex. L-B1-01-Staff-024, Ex. L-B1-01-Staff-025, Ex. L-B1-01-Staff-026, Ex. L-B1-01-Staff-027, Ex. L-B1-01-Staff-030, Ex. L-B3-04-Staff-031, Ex. L-B1-01-VECC-004, Ex. L-B1-01-VECC-005
Undertakings	JT2.15, JT2.27, JT2.36, JT2.39

CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 6.1 Are OPG's proposed capital structure and rate of return on equity ("ROE") appropriate?

Complete Settlement

The Parties agree for the capital structure to remain unchanged from EB-2016-0152 at 45% equity and 55% debt for the purposes of determining the nuclear revenue requirements for the 2022-2026 period.

The Parties agree to set the ROE rate for the IR term as per OPG's proposal discussed above in Section 2, Part C, subpart (ii).

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-2-2 (Approvals), Ex. A1-3-1 (Summary of Application), Ex. C1-1-1 (Capital Structure and Return on Equity), Ex. I1-1-1 (Summary of Revenue Requirement and Revenue Deficiency)
Interrogatories	Ex. L-A1-03-Staff-008, Ex. L-C1-01-Staff-043, Ex. L-C1-01-Staff-044, Ex. L-C1-01-Staff-050, Ex. L-C1-01-Staff-060, Ex. L-C1-01-Staff-064, Ex. L-C1-01-CCC-024, Ex. L-C1-01-CCC-027, Ex. L-C1-01-Energy Probe-008, Ex. L-C1-01-SEC-024, Ex. L-C1-01-SEC-025, Ex. L-C1-01-SEC-026, Ex. L-C1-01-SEC-031
Undertakings	JT2.34, JT3.1, JT4.10, JT4.11, JT3.4, JI1.1

Issue 6.2 Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Complete Settlement

The Parties agree to set the long-term cost of debt rate and short-term cost of debt rate for the 2022-2026 period as proposed by OPG and discussed above in Section 2, Part C, subpart (ii).

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-2-2 (Approvals), Ex. A1-3-1 (Summary of Application), Ex. A2-1-1 (Financial Statement), Ex. C1-1-2 (Cost of Long-Term Debt), Ex. C1-1-3 (Cost of Short-Term Debt)
Interrogatories	Ex. L-C1-01-Staff-036, Ex. L-C1-01-Staff-037, Ex. L-C1-01-Staff-038, Ex. L-C1-01-Staff-039, Ex. L-C1-01-CCC-028, Ex. L-C1-01-Energy Probe-012, Ex. L-C1-01-Energy Probe-013, Ex. L-A2-03-SEC-015
Undertakings	JT3.19

7. CAPITAL PROJECTS

Issue 7.1 ***Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg 53/05 and proposed for recovery meet the requirements of that section?***

Issue 7.2 ***Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?***

Issue 7.3 ***Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?***

Issue 7.4 ***Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?***

Issue 7.5 ***Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?***

Complete Settlement

The Parties agree that the nuclear projects identified by OPG as being subject to section 6(2)4 of O.Reg. 53/05 and proposed for recovery meet the requirements of that section.

The Parties agree that forecasted nuclear capital expenditures and/or financial commitments and in-service additions for the DRP (other than the D2O Project) are reasonable and appropriate and form part of the settled forecast rate base for the 2022-2026 period on the basis that they remain within the total $12.8B project budget first set

out in EB-2016-0152. The OEB will review the prudence of any amounts sought by OPG in excess of the $12.8B total, the appropriateness of any future material changes to the scope of the DRP and any corresponding changes in contracts, when OPG seeks disposition of the actual DRP costs through the Capacity Refurbishment Variance Account.

With respect to the Nuclear Operations projects, the Parties agree to reduce the forecast in-service additions by 13% per year for the 2022-2026 period. The Parties further agree to reduce the forecast in-service additions for Corporate Support Services by 5% per year for the 2022-2026 period.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. D2-1-1 (Project and Portfolio Management – Nuclear), Ex. D2-1-2 (Capital Expenditures – Nuclear Operations), Ex. D2-1-3 (Capital Projects – Nuclear), Ex. D2-2-1-Ex. D2-2-11 (Darlington Refurbishment Program), Ex. D3-1-1 (Capital Budget – Support Services), Ex. D3-1-2 (Capital Projects – Support Services), Ex. F2-3-1 (Project OM&A – Nuclear), Ex. F2-3-3 (Comparison of Project OM&A – Nuclear)
Interrogatories	Nuclear Operations: Ex. L-B1-01-SEC-016, Ex. L-D2-01-AMPCO-013, Ex. L-D2-01-AMPCO-038, Ex. L-D2-01-AMPCO-039, Ex. L-D2-01-AMPCO-040, Ex. L-D2-01-AMPCO-045-AMPCO-057, Ex. L-D2-01-AMPCO-058, Ex. L-D2-01-AMPCO-059, Ex. L-D2-01-SEC-049, Ex. L-D2-01-Staff-088, Ex. L-D2-01-Staff-089, Ex. L-D2-01-Staff-090, Ex. L-D2-01-Staff-091, Ex. L-D2-01-AMPCO-069, Ex. L-D2-01-AMPCO-072, Ex. L-D2-01-Staff-092, Ex. L-D2-01-Staff-093, Ex. L-D2-01-Staff-112, Ex. L-D2-01-Staff-113, Ex. L-D2-01-Staff-119, Ex. L-D2-01-Staff-120, Ex. L-H1-01-Staff-328 DRP: Ex. L-D2-02-Staff-141, Ex. L-D2-02-Staff-143, Ex. L-D2-02-PWU-009, Corporate Support Services Capital:

	Ex. L-D3-01-AMPCO-139, Ex. L-D3-01-CCC-040, Ex. L-D3-01-Energy Probe-047, Ex. L-D3-01-SEC-110, Ex. L-D3-01-SEC-109, Ex. L-D3-01-SEC-112, Ex. L-D3-01-SEC-113, Ex. L-D3-01-Staff-177, Ex. L-D3-01-Staff-178, Ex. L-D3-01-Staff-179
Undertakings	JT1.22, JT1.23, JT1.25, JT2.01, JT2.13, JT2.15, JT2.17, JT3.08, JT3.12, JT3.23

Issue 7.6 Are the proposed test period in-service additions for the D2O Project reasonable?

No Settlement

The Parties did not reach an agreement as to whether the proposed in-service additions for the D2O Project are reasonable.

8. PRODUCTION FORECASTS

Issue 8.1 Is the proposed nuclear production forecast appropriate?

Complete Settlement

The Parties agree to the modified nuclear production forecast as set out in Section 2, Part D of this Settlement Proposal.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. E2-1-1 (Production Forecast and Methodology – Nuclear), Ex. E2-1-2 (Comparison of Production Forecasts – Nuclear)
Interrogatories	Ex. L-A2-02-Staff-018, Ex. L-E2-01-Staff-181, Ex. L-E2-01-Staff-182, Ex. L-E2-01-Staff-184, Ex. L-E2-01-Staff-185, Ex. L-E2-01-Staff-186, Ex. L-E2-01-Staff-187, Ex. L-E2-01-Staff-189, Ex. L-E2-01-Staff-190, Ex. L-E2-01-Staff-191, Ex. L-E2-01-Staff-208, Ex. L-E2-01-CCC-042, Ex. L-E2-01-CCC-043, Ex. L-E2-01-CCC-044, Ex. L-E2-01-Environmental Defence-007, Ex. L-E2-01-Energy Probe-050, Ex. L-E2-01-Energy

	Probe-051, Ex. L-E2-01-OAPPA-002, Ex. L-E2-01-OAPPA-003, Ex. L-E2-01-SEC-114, Ex. L-E2-01-VECC-022, Ex. L-F2-01-Staff-208
Undertakings	JT1.21, JT2.34, JT2.37

9. and 10. OM&A COSTS

Issue 9.1 ***Are the test period human resource related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension and other post-employment benefit costs) appropriate?***

Issue 10.1 ***Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?***

Issue 10.3 ***Are the corporate costs allocated to the nuclear business appropriate?***

Issue 10.4 ***Are the centrally held costs allocated to the nuclear business appropriate?***

Issue 10.5 ***Are the asset service fee amounts charged to the nuclear business appropriate?***

Complete Settlement

The Parties have settled Issues 9.1, 10.1, 10.3, 10.4 and 10.5, including accepting OPG's cost allocation and asset service fee methodology.

The Parties agree to reduce the proposed total OM&A expenses, excluding Darlington Refurbishment OM&A, Darlington New Nuclear OM&A and Centrally Held Costs, but including Asset Service Fees, for each year of the 2022-2026 period by 3.0%. In addition to Asset Service Fees, the reduction applies to each of Nuclear Operations OM&A and the Allocation of Corporate Costs OM&A. The Parties agree to Darlington Refurbishment OM&A, Darlington New Nuclear OM&A and Centrally-Held Costs as proposed by OPG.

In addition, the Parties agree to exclude the planned Clarington Corporate Campus from the Asset Service Fees included in the revenue requirements for the IR term. The Parties agree that OPG will establish a Clarington Corporate Campus Deferral Account to record the revenue requirement impact of capital expenditures and operating costs for the Clarington Corporate Campus, calculated on the same basis as OPG's existing Asset Service Fee methodology. Settlement with respect to this aspect is without prejudice to any position that a Party may take with respect to the appropriateness of cost recovery of the Clarington Corporate Campus project capital costs. Parties agree that these matters will be addressed when OPG seeks to dispose of the deferral account.

The Parties also agree to adjust OM&A expenses for the impact of the agreed-upon capital structure on the remaining Asset Service Fees for the 2022-2026 period.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. F2-2-1 (Base OM&A – Nuclear Operations), Ex. F2-2-2 (Comparison of Base OM&A – Nuclear), Ex. F2-3-1 (Project OM&A – Nuclear), Ex. F2-3-2 (Comparison of Project OM&A – Nuclear), Ex. F2-3-3 (Details of OM&A Projects – Nuclear), Ex. F2-4-1 (Outage OM&A – Nuclear), Ex. F2-4-2 (Comparison of Nuclear Outage OM&A), Ex. F2-6-1 (OM&A Purchased Services – Nuclear Operations), Ex. F2-7-1 (Darlington Refurbishment Program OM&A), Ex. F3-1-1 (Allocation of Support Services Costs), Ex. F3-1-2 (Comparison of Allocation of Support Services Costs), Ex. F3-1-3 (Comparison of Regulatory Affairs Costs), Ex. F3-2-1 (Asset Service Fees), Ex. F3-2-2 (Comparison of Asset Service Fees), Ex. F3-3-2 (OM&A Purchased Services – Support Services), Ex. F4-3-1 (Compensation and Benefits), Ex. F4-3-2 (Pension and Other Post Employment Benefit Costs), Ex. F4-4-1 (Centrally-Held Costs)
Interrogatories	Ex. L-A1-03-AMPCO-002, Ex. L-F2-01-AMPCO-143, Ex. L-F2-01-Staff-212, Ex. L-F2-01-Staff-213, Ex. L-F2-01-Staff-214, Ex. L-F2-01-VECC-025, Ex. L-F2-01-VECC-026, Ex. L-F2-02-AMPCO-144, Ex. L-F2-02-AMPCO-145, Ex. L-F2-02-AMPCO-146, Ex. L-F2-02-AMPCO-147, Ex. L-F2-02-AMPCO-148, Ex. L-F2-02-Staff-229, Ex. L-F2-03-AMPCO-151, Ex. L-F2-03-Staff-233, Ex. L-F2-02-Staff-224, Ex. L-F2-02-Staff-225, Ex. L-F2-02-Staff-226, Ex. L-F2-02-Staff-227, Ex. L-F2-02-Staff-228, Ex. L-F2-02-Staff-229, Ex. L-F2-03-SEC-160, Ex. L-F2-03-Staff-231, Ex. L-F2-03-Staff-232, Ex. L-F2-03-Staff-233, Ex. L-F2-03-Staff-234, Ex. L-F2-03-Staff-235, Ex. L-F2-02-Staff-230, Ex. L-F2-04-Staff-236, Ex. L-F2-04-Staff-237, Ex. L-F2-04-Staff-238, Ex. L-F3-01-Energy Probe-055, Ex. L-F3-01-Energy Probe-056, Ex. L-F3-01-LLPMA-012, Ex. L-F3-01-Staff-250, Ex. L-F3-01-Staff-253, Ex. L-F3-01-Staff-254, Ex. L-F4-03-AMPCO-162, Ex. L-F4-03-PWU-018, Ex. L-F4-03-PWU-026, Ex. L-F4-03-SEC-145, Ex. L-F4-03-SEC-149, Ex. L-F4-03-SEC-152, Ex. L-F4-03-Staff-275, Ex. L-F4-03-Staff-277, Ex. L-F4-03-Staff-279, Ex. L-F4-03-Staff-280, Ex. L-F4-03-Staff-282, Ex. L-F4-03-Staff-283, Ex. L-F2-07-Staff-246

	Clarington Corporate Campus: Ex. L-D3-01-SEC-111, Ex. L-F3-02-Energy Probe-059, Ex. L-D3-01-Society-005, Ex. L-D3-01-Society-006, Ex. L-D3-01-Society-007, Ex. L-D3-01-Society-008, Ex. L-D3-01-Society-009, Ex. L-D3-01-Society-012, Ex. L-D3-01-Staff-176
Undertakings	JT1.18, JT2.02, JT2.03, JT2.05, JT2.06, JT2.07, JT2.08, JT2.09, JT2.15, , JT3.07, JT4.08, JT4.09, JT4.13, JTX4.17, JTX4.18 Clarington Corporate Campus: JT2.28, JT2.29, JT2.30, JT2.32, JT2.33, JT4.2, JT4.4, JT4.15, JTX4.19, JTX4.16

Issue 10.2 Is the forecast of nuclear fuel costs appropriate?

Complete Settlement

The Parties agree to reduce nuclear fuel bundle costs by 2% for each year of the 2022-2026 IR term. The settled nuclear fuel costs also include the flow through impacts of the production forecast adjustments. The Parties agree to the remaining components of fuel costs as proposed by OPG.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. F2-5-1 (Nuclear Fuel Costs), Ex. F2-5-2 (Comparison of Nuclear Fuel Costs)
Interrogatories	Ex. L-F2-01-Staff-211, Ex. L-F2-05-Staff-239, Ex. L-F2-05-Staff-240, Ex. L-F2-05-Staff-241, Ex. L-F2-05-Staff-242, Ex. L-F2-05-Staff-243, Ex. L-F2-05-Staff-244, Ex. L-F2-05-Staff-245, Ex. L-F2-05-SEC-129, Ex. L-F2-05-SEC-130, Ex. L-F2-05-SEC-131
Undertakings	JT1.21

Depreciation

Issue 10.6 Is the proposed test period nuclear depreciation expense appropriate?

Complete Settlement

Subject to the adjustments in connection with modifications to the forecasted in-service capital additions and pending the OEB's decision on the D2O Project, the Parties agree that the proposed nuclear depreciation and amortization expense for the IR term is appropriate.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. F4-1-1 (Depreciation and Amortization)
Interrogatories	Ex. L-F4-01-Staff-269, Ex. L-F4-01-LPMA-013, Ex. L-F4-01-SEC-137, Ex. L-F4-01-SEC-138
Undertakings	JT2.39

Income and Property Taxes

Issue 10.7 Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Complete Settlement

Subject to adjustments in connection with modifications to the forecasted capital in-service additions and pending the OEB's decision on the D2O Project, the Parties agree that the proposed income tax and property tax amounts for the IR term are appropriate.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. F4-2-1 (Taxes)
Interrogatories	Ex. L-C2-01-Staff-084, Ex. L-F4-02-Staff-272, Ex. L-F4-02-Staff-273, Ex. L-F4-02-Staff-274, Ex. L-G2-02-Staff-319, Ex. L-H1-01-Staff-326, Ex. L-F4-02-SEC-140, Ex. L-F4-02-SEC-139, Ex. L-F4-02-SEC-141
Undertakings	JT3.14, JT3.16

11. OTHER REVENUES

Issue 11.1 Are the forecasts of nuclear business non-energy revenues appropriate?

Complete Settlement

The Parties agree to increase, by 10%, OPG's proposed annual forecast of nuclear non-energy revenues (net of related costs) for the 2022-2026 period.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. G2-1-1 (Nuclear Non-Energy Revenues), Ex. G2-1-2 (Comparison of Non-Energy Revenues – Nuclear)
Interrogatories	Ex. L-G2-01-AMPCO-177, Ex. L-G2-01-CCC-052, Ex. L-G2-01-CCC-053, Ex. L-G2-01-Energy Probe-065, Ex. L-G2-01-SEC-153, Ex. L-G2-01-VECC-036
Undertakings	None

Issue 11.2 Are the test period costs related to the Bruce Generating Station, and costs and revenues related to the Bruce lease appropriate?

Complete Settlement

The Parties agree that OPG's forecast revenue related to the Bruce lease and costs related to the Bruce nuclear generating stations for the 2022-2026 period are appropriate.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. G2-2-1 (Bruce Generating Station – Revenues and Costs)
Interrogatories	Ex. L-G2-02-Energy Probe-066, Ex. L-G2-02-OAPPA-009, Ex. L-G2-02-OAPPA-010, Ex. L-G2-02-Staff-318, Ex. L-G2-02-Staff-319
Undertakings	JT3.15, JT3.23

12. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

Issue 12.1 Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate?

Issue 12.2 Is the revenue requirement impact of the nuclear liabilities appropriately determined?

Complete Settlement

The Parties agree that the revenue requirement methodology for recovering OPG's nuclear liabilities in relation to nuclear waste management and decommissioning costs is appropriate. The Parties agree that the 2022-2026 revenue requirement impacts of the nuclear liabilities are appropriately determined.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. C2-1-1 (Nuclear Waste Management and Decommissioning – Revenue Requirement Impact of Nuclear Liabilities)
Interrogatories	Ex. L-C2-01-Staff-074, Ex. L-C2-01-Staff-075, Ex. L-C2-01-Staff-076, Ex. L-C2-01-Staff-077, Ex. L-C2-01-Staff-078, Ex. L-C2-01-Staff-079, Ex. L-C2-01-Staff-080, Ex. L-C2-01-Staff-081, Ex. L-C2-01-Staff-082, Ex. L-C2-01-Staff-083, Ex. L-C2-01-Staff-085, Ex. L-C2-01-Staff-086, Ex. L-C2-01-Staff-087, Ex. L-C2-01-CCC-029, Ex. L-C2-01-CCC-030, Ex. L-C2-01-Energy Probe-014
Undertakings	JT3.15, JT3.23

13. DEFERRAL AND VARIANCE ACCOUNTS

Issue 13.1 ***Is the nature or type of costs recorded and the methodologies used to record costs in the deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?***

Issue 13.2 ***Are the balances for recovery and the proposed disposition amounts in each of the deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?***

Issue 13.3 ***Is the proposed continuation of deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?***

Issue 13.4 ***Are the deferral and variance accounts that OPG proposes to establish appropriate?***

Issue 13.5 ***Should the net sale proceeds of an unprescribed asset be recorded in a deferral and variance account?***

Partial Settlement for 13.1 and 13.2
Complete Settlement for 13.3-13.5

Subject to the OEB's decision on the D2O Project, the Parties agree that OPG shall recover all balances as proposed, with the exception of a $40.0M portion of the debit balances recorded in the Hydroelectric Surplus Baseload Generation Variance Account. The clearance of this $40.0M amount is deferred until the proceeding addressing any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP, where the OEB expects concurrently there will be a review of OPG's approach to Surplus Baseload Generation ("**SBG**").[42]

[42] OEB's Decision on the Issues List (May 20, 2021), p. 6.

The Parties also agree that in the future in seeking clearance of the Hydroelectric Surplus Baseload Generation Variance Account, OPG shall demonstrate that it operates its regulated fleet based on the standard of minimizing total electricity supply costs (including market and regulated payments while avoiding economic loss) to customers, subject to unavoidable considerations for the safety of any persons, equipment damage, or the violation of any applicable law ("SEAL") and unavoidable physical constraints. OPG will report on how it has met this standard each time it seeks clearance of the Hydroelectric Surplus Baseload Generation Variance Account. OPG's report will identify each time that OPG did not operate its regulated fleet to minimize total electricity supply costs during hours when OPG is booking additions to this variance account because doing so would cause OPG to experience an economic loss, and explain why operating to minimize total electricity supply costs would have caused economic loss in each case.

The Parties also agree to continue existing deferral and variance accounts using the methodologies that have been used to record entries into these accounts to date as approved by the OEB, as proposed by OPG. This includes maintaining the Pension & OPEB Cost Variance Account for nuclear facilities to resume recording of variances between: (i) pension and OPEB accrual costs, plus related income tax PILs, reflected in the current revenue requirement and; (ii) OPG's actual pension and OPEB accrual costs, and associated income tax impacts. No further additions will be recorded in the Pension & OPEB Cash Payment Variance Account as well as the Pension & OPEB Cash Versus Accrual Differential Deferral Account, as of January 1, 2022 for nuclear facilities as the nuclear revenue requirements in this proceeding reflect pension and OPEB costs calculated on an accrual basis. The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account for nuclear facilities will continue to operate as detailed in Appendix E to the Draft Payment Amounts Order. The Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account will record only interest and amortization, as applicable, for nuclear facilities.

For hydroelectric facilities, the Pension and OPEB Cost Variance Account will continue to record only amortization, as applicable. The Pension & OPEB Cash Payment Variance Account as well as the Pension & OPEB Cash Versus Accrual Differential Deferral Account will continue to operate as in the previous payment amount period until OPG rebases hydroelectric payment amounts. The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account will continue to operate as detailed in Appendix E to the Draft Payment Amounts Order.

As discussed in greater detail in Section 2, Part G, the Parties also agree to establish four new accounts (Impact for IFRS Deferral Account, Clarington Corporate Campus Deferral Account, Earnings Sharing Deferral Account and Sale of Unprescribed Kipling Site Deferral Account).

In consideration of the aforementioned, the Parties have settled Issues 13.1 and 13.2, except as they relate to the recording of SMR related costs in the Nuclear Development Variance Account, and the year-end 2019 balances in the Capacity Refurbishment

Variance Account sought for recovery by OPG for the D2O Project. Issues 13.3-13.5 are fully settled.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. H1-1-1 (Deferral and Variance Accounts), Ex. H1-2-1 (Clearance of Deferral and Variance Accounts)
Interrogatories	Ex. L-D3-01-Society-007, Ex. L-F3-02-Staff-264, Ex. L-F4-01-Staff-271, Ex. L-H1-01-CCC-054, Ex. L-H1-01-Energy Probe-068, Ex. L-H1-01-OSEA-012, Ex. L-H1-01-SEC-155, Ex. L-H1-01-Staff-322, Ex. L-H1-01-Staff-324, Ex. L-H1-01-Staff-325, Ex. L-H1-01-Staff-326, Ex. L-H1-01-Staff-328, Ex. L-H1-01-Staff-330, Ex. L-H1-01-Staff-331, Ex. L-H1-01-Staff-332, Ex. L-H1-01-Staff-333, Ex. L-H1-01-Staff-334, Ex. L-H1-01-Staff-337, Ex. L-H1-02-Energy Probe-070, Ex. L-H1-02-Staff-339, Ex. L-H1-02-Staff-340
Undertakings	JT3.12, JT2.21, JT2.22

14. REPORTING AND RECORD KEEPING REQUIREMENTS

Issue 14.1 Are the proposed reporting and record keeping requirements, including performance scorecards proposed by OPG, appropriate?

Partial Settlement

The Parties agree to the reporting and record keeping requirements set out in Appendix A hereto, except as they relate to SMRs. The Parties also agree that OPG will undertake certain independent studies, reports, and other filings as set out in Appendix A hereto.

With respect to the basis for the SBG annual reporting requirements, OPG agrees to file a revised version of Ex. JT2.22 on an hourly resolution as soon as practicable upon the OEB's approval of this Settlement Proposal.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC

Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-3-2 (Nuclear Rate-Setting Framework and Performance Reporting)
Interrogatories	Ex. L-A1-03-CCC-007, Ex. L-A1-03-Staff-012, Ex. L-A1-03-Staff-013
Undertakings	JI1.1

15. RATE SMOOTHING

Issue 15.1 Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

No Settlement

The Parties agree to defer the consideration of rate smoothing to the process of establishing the final payment amounts order arising from the OEB's decision on this Settlement Proposal and the remaining issues to be considered by the OEB in the pending hearing.

16.1 IMPLEMENTATION

Issue 16.1 Are the effective dates for new payment amounts and riders appropriate?

Complete Settlement

The Parties agree that the effective date for new payment amounts and riders shall be January 1, 2022.

Approval

Parties in Support: OPG, AMPCO, CME, CCC, Energy Probe, LPMA, OAPPA, OSEA, QMA, SEC, VECC
Parties Taking no Position: Environmental Defence, PWU, Society

Evidence

The evidence in relation to this issue includes the following:

Exhibits	Ex. A1-2-2 (Approvals)

Interrogatories	None
Undertakings	None

APPENDIX A – REPORTING AND RECORD KEEPING REQUIREMENTS

List of OPG reporting requirements to filed with the OEB (OPG reporting shall be posted on OEB's website and OPG's website, for public access – redacted as necessary):

- Unaudited balances of deferral and variance accounts within 60 days after calendar quarter end
- The MD&A and financial statements as filed with the Ontario Securities Commission within 60 days for the first three quarters, and within 120 days for December year-end statements as long as the Ontario Securities Commissions requires these documents to be filed
- Nuclear unit capability factors and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year end as reported in OPG's quarterly and annual MD&A
- FTE information by April 30 each year
- Capital in-service additions and construction work in progress by April 30 each year
- An analysis of the actual annual regulatory return, after tax on rate base, dollars for the regulated business as a whole and separately for its regulated nuclear and hydroelectric business segments, and a percentage for the regulated business based on OPG's approved capital structure, and a comparison with the regulatory return included in the payment amounts by July 31 of each year, in the format presented in Ex. L-H1-01-AMPCO-178, Attachment 1. Additionally and in consideration of the settlement, OPG agrees to provide, as part of this annual reporting, a calculation equivalent to dividing the actual dollar regulatory return for each of the regulated nuclear and hydroelectric business segments by 45% of the corresponding rate base for each of these segments, where 45% is the equity thickness in the agreed upon capital structure for the regulated business.
- Annual report on expenses related to nuclear liability by June 30
- Annual hydroelectric performance report by April 30
- Annual nuclear performance report by April 30 (Annual nuclear performance report is re-filed with benchmark quartile results no later than November 30)
- Annual Darlington Refurbishment Report
- Pickering Closure Costs Deferral Account – Annual reporting by April 30 of each year on amounts recorded broken down by the major categories in O. Reg 53/05 Section 5.6 with no reporting of such amounts until cumulative balance exceeds $50M
- Hydroelectric surplus baseload generation ("**SBG**") – Annual reporting by June 30:
  1) all SBG claimed amounts including total MW on an hourly basis by each regulated facility, and the calculation of these amounts booked in the Hydroelectric Surplus Baseload Generation Variance Account;
  2) information in relation to usage of the Sir Adam Beck Pump Generating Station as provided in Ex. JT2.22, revised to an hourly resolution.

List of Independent Studies / Reports for next OPG payment amount proceeding.

- General/Custom IR Framework

- Customer Engagement Study (continue)
- Total Factor Productivity Study and Total Cost Benchmarking for Hydroelectric (if proposing a IRM / CIR)
- Total Factor Productivity Study and/or Total Cost Benchmarking for Nuclear (if proposing a IRM / CIR – or explanation as to why it cannot be done for the next major payment amount application)
- Assessment on OPG's execution of the DRP (if seeking incremental DRP amounts and associated DRP-related CRVA clearance) (new)

- Benchmarking
  - Nuclear Staffing Benchmarking (continue)
  - Nuclear Benchmarking Approach Review (continue)
  - Corporate Costs Benchmarking (continue)

- Compensation and Staffing
  - Compensation Benchmarking Study on the current two-segment benchmarking approach only (continue)
  - Pension / OPEBs – most recent actuarial funding valuation, Report on Estimated Accounting Cost for Post-Employment Benefit Plans, Report on the Accounting Cost for Post-Employment Benefit Plans (continue)

- Other Matters
  - Cost Allocation Study (continue)
  - Depreciation Study (continue)
  - Summary of all internal audit reports (same format as Ex. L-A1-02-SEC-011, Attachment 2) completed subsequent to any that are listed in Ex. L-A1-02-SEC-011, Attachment 1 (new)

EB-2020-0290

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

July 16, 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 panels of witnesses. 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 in-service additions related to OPG's Heavy Water Storage and Drum Handing 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 rate smoothing (collectively, the "Outstanding Issues").

The Settlement Proposal was filed with the OEB on July 16, 2021 as Exhibit O.

[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.

In conjunction with the Settlement Proposal, OPG filed a draft payment amounts order ("Draft Order") on July 16, 2021 based on the Settlement Proposal and OPG's proposed in-service additions for the D2O Storage Project. The Draft Order included a revised Revenue Requirement Work Form (Appendix G to the Draft Order). With the exception of the impacts of the Outstanding Issues, the Draft Order had been reviewed and agreed to by the parties to the Settlement Proposal.

The OEB issued a Decision and Order approving the settlement proposal on ● (the "Decision"). A copy of the OEB-approved Settlement Proposal was attached as Schedule ● of the Decision.

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Nuclear Revenue Requirement:[2] The IR term nuclear revenue requirements, net of stretch factor adjustments, are $3,511.7M in 2022, $3,425.9M in 2023, $3,510.5M in 2024, $3,188.0M in 2025, and $2,428.5M 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

[2] Subject to any adjustments from the OEB's decision on the D2O Storage Project and final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order.

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"):[3] Effective January 1 of each year, the NPA over the IR Term is as follows: $102.06/MWh in 2022, $105.68/MWh in 2023, $103.25/MWh in 2024, $102.54/MWh in 2025, and $110.84/MWh in 2026, as set out in Appendix B, Table 1, line 3. These payment amounts reflect the rate smoothing approach set out in Appendix ● and the resulting nuclear rate smoothing deferral amounts approved below.

5. Nuclear Rate Smoothing Deferral Amounts:[4] The nuclear deferral amounts to be recorded in the Rate Smoothing Deferral Account are $82.4M in 2022 and $125.7M in 2023, for a total of $208.2M of deferred revenue. There will be no additions to the Rate Smoothing Deferral Account 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[5];
   - Income and Other Taxes Variance Account;
   - Capacity Refurbishment Variance Account[6];

[3] Subject to any adjustments to the rate smoothing proposal as part the process of establishing the final payment amounts order.
[4] Subject to any adjustments from the OEB's decision on the D2O Storage Project, the final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order, and any adjustments to the rate smoothing proposal as part the process of establishing the final payment amounts order.
[5] 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.
[6] 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.

- Niagara Tunnel Project pre-December 2008 Disallowance Variance Account;
- Pension and OPEB Cost Variance Account;
- Pension & OPEB Cash Payment Variance Account;
- Pension & OPEB Cash Versus Accrual Differential Deferral Account;
- Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account;
- Nuclear Development Variance Account[7];
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts[8];
- 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 and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account;
   - Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account;

[7] Clearance of the portion of the Nuclear Development Variance Account related to small modular reactors is deferred to a future application.
[8] 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[9];
   - 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

[9] 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, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, is $0.69/MWh (Appendix C, Table 1, line 23, cols. (h) to (l)). The approved disposition amount for this proceeding from regulated hydroelectric deferral and variance accounts, reflecting approved recovery of the audited December 31, 2019 balances in deferral and variance accounts, less amortization amounts for 2020 and 2021 approved in EB-2016-0152 and EB-2018-0243, plus additional net amounts for the income tax impact associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and other adjustments, is a debit of $147.7M (Appendix C, Table 1, line 21, col. (m)). The HPR will apply to 50% of the output of OPG's Chats Falls Generating Station.

10. Nuclear Payment Rider ("NPR"):[10] 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 $1.74/MWh for January 1, 2022 to December 31, 2022, $1.87/MWh for January 1, 2023 to December 31, 2023, $1.72/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, cols. (h) to (l)). The approved disposition amount for this proceeding from nuclear deferral and variance accounts, reflecting approved recovery of the audited December 31, 2019 balances in deferral and variance accounts, less amortization amounts for 2020 and 2021 approved in EB-2016-0152 and EB-2018-0243, plus additional net amounts for the income tax impact associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and other adjustments, is a debit of $507.7M (App. D, Table 1, col. (m), line 30).

[10] Subject to any adjustments from the OEB's decision on 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

_____
Christine Long
Registrar

EB-2020-0290 PAYMENT AMOUNTS ORDER – APPENDICES

TABLE OF CONTENTS

APPENDIX A: NUCLEAR REVENUE REQUIREMENT

Table 1	2022 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 1a	Notes to Table 1
Table 2	2023 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 2a	Notes to Table 2
Table 3	2024 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 3a	Notes to Table 3
Table 4	2025 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 4a	Notes to Table 4
Table 5	2026 Summary of Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 5a	Notes to Table 5
Table 6	2022 to 2026 Summary of Proposed Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts
Table 6a	Notes to Table 6
Table 7	Calculation of Nuclear Stretch Factor
Table 7a	Notes to Table 7
Table 8	Summary of Settled Revenue Deficiency Subject to D2O Project - Nuclear
Table 9	Continuity of Settled Property, Plant and Equipment Subject to D2O Project - Nuclear
Table 9a	Notes to Table 9
Table 10	Continuity of Settled Accumulated Depreciation and Amortization Subject to D2O Project - Nuclear
Table 10a	Notes to Table 10
Table 11	2022 Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
Table 12	2023 Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project

Table 13	2024 Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
Table 14	2025 Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
Table 15	2026 Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
Table 16	2017-2021 Continuity of Property, Plant and Equipment Subject to Long-Term Debt Rate- Nuclear
Table 16b	2017-2021 Continuity of Accumulated Depreciation and Amortization for In-service Amounts Subject to Long-Term Debt Rate- Nuclear
Table 16c	2022-2026 Continuity of Accumulated Depreciation and Amortization for In-service Amounts Subject to Long-Term Debt Rate- Nuclear
Table 16d	Notes to Table 16, 16b and 16c
Table 17	2022 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities
Table 17a	Notes to Table 17
Table 18	2023 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities
Table 18a	Notes to Table 18
Table 19	2024 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities
Table 19a	Notes to Table 19
Table 20	2025 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities
Table 20a	Notes to Table 20
Table 21	2026 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities
Table 21a	Notes to Table 21
Table 22	2022-2026 Summary of Nuclear Regulatory Tax Losses

APPENDIX B: NUCLEAR PAYMENT AMOUNTS

Table 1	Payment Amounts – Nuclear
Table 2A	Annualized Residential Consumer Impact
Table 2B	Annualized Bill Impact for Typical Alectra (PowerStream) Consumers 2022-2026
Table 2C	Annualized Bill Impact for Typical Hydro One Networks Consumers 2022-2026
Table 2D	Annualized Bill Impact for Typical Toronto Hydro Consumers 2022-2026
Table 3	Computation of Percentage Change in Payment Amounts

APPENDIX C: REGULATED HYDROELECTRIC PAYMENT RIDERS

Table 1 Calculation of Deferral and Variance Account Recovery Payment Rider – Regulated Hydroelectric

APPENDIX D: NUCLEAR PAYMENT RIDERS

Table 1 Calculation of Deferral and Variance Account Recovery Payment Rider – Nuclear

APPENDIX E: CLEARANCE AND CONTINUATION OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

APPENDIX F: ACCOUNTING ORDERS

APPENDIX G: REVENUE REQUIREMENT WORK FORM

APPENDIX ●: PAYMENT AMOUNT SMOOTHING

Numbers may not add due to rounding.

Table 1

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

Line No.	Description	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D20 Project
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	8,030.7	(29.2)	8,001.5
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	(29.2)	8,689.7
	Capitalization				
5	**Short-term Debt**	3	51.1	(0.1)	51.0
6	**Long-Term Debt**	3	4,271.6	416.3	4,687.9
7	**Common Equity at ROE Rate**	3	4,322.7	(574.3)	3,748.4
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	(29.2)	8,689.7
	Cost of Capital				
10	**Short-term Debt**	3	2.9	(0.0)	2.9
11	**Long-Term Debt**	3	154.0	15.0	169.0
12	**Return on Equity at ROE Rate**	3	360.5	(47.9)	312.6
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	(28.2)	492.8
	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	(1.4)	550.1
18	**Property Tax**		12.9	0.0	12.9
19	**Total Expenses**		3,083.4	(66.9)	3,016.5
	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	(97.6)	3,511.7
	(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	(97.6)	3,511.7
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(19.2)	58.4
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,686.9	(116.8)	3,570.1

For notes see Table 1a.

Numbers may not add due to rounding.

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 Updated to reflect the settlement proposal reduction (Settlement Proposal, 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.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the capital structure per the settlement proposal of 45% Equity : 55% Debt (Settlement Proposal, P. 24). 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 settlement proposal (Settlement Proposal, P. 23). See PAO App. A, Table 11 for supporting details.

5 Updated to reflect the 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 (Settlement Proposal, 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 Updated to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the settlement proposal (Settlement Proposal, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the settlement proposal (Settlement Proposal, 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) (Settlement Proposal, 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) (Settlement Proposal, 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 Updated to reflect a 10% increase in ancillary and other revenues forecast per the settlement proposal (Settlement Proposal, P. 27).

8 Updated to reflect the impacts of the settlement proposal as outlined above per PAO App. A, Table 17.

9 Per the settlement proposal, updated to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Settlement Proposal, P. 18), expand the scope of the stretch factor to include asset service fees (Settlement Proposal, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding DRP (Settlement Proposal, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Updated to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the settlement proposal (Settlement Proposal, P. 19). See PAO App. D, Table 1, line 29.

Numbers may not add due to rounding.

Table 2

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

Line No.	Description	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D20 Project
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	8,103.2	(87.4)	8,015.9
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	(87.4)	8,701.5
	Capitalization				
5	**Short-term Debt**	3	50.9	(0.2)	50.6
6	**Long-Term Debt**	3	4,343.6	391.6	4,735.2
7	**Common Equity at ROE Rate**	3	4,394.4	(591.7)	3,802.7
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	(87.4)	8,701.5
	Cost of Capital				
10	**Short-term Debt**	3	3.0	(0.0)	3.0
11	**Long-Term Debt**	3	151.4	13.6	165.0
12	**Return on Equity at ROE Rate**	3	366.5	(49.4)	317.1
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	(31.8)	489.1
	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	(4.1)	465.9
18	**Property Tax**		13.2	0.0	13.2
19	**Total Expenses**		3,047.0	(71.6)	2,975.4
	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	(107.5)	3,440.8
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	9.5	5.4	14.9
26	**Revenue Requirement Net of Stretch Factor**		3,538.8	(112.9)	3,425.9
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(19.2)	58.4
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,616.5	(132.1)	3,484.3

For notes see Table 2a.

Numbers may not add due to rounding.

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 Updated to reflect the settlement proposal reduction (Settlement Proposal, 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.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.
3 Updated to reflect the capital structure per the settlement proposal of 45% Equity : 55% Debt (Settlement Proposal, P. 24). 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 settlement proposal (Settlement Proposal, P. 23). See PAO App. A, Table 11 for supporting details.
5 Updated to reflect the 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 (Settlement Proposal, 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 Updated to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the settlement proposal (Settlement Proposal, P. 26) and the flow through impact of an upwards 0.4TWh adjustment per the settlement proposal (Settlement Proposal, 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) (Settlement Proposal, 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) (Settlement Proposal, 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 Updated to reflect a 10% increase in ancillary and other revenues forecast per the settlement proposal (Settlement Proposal, P. 27).
8 Updated to reflect the impacts of the settlement proposal as outlined above per PAO App. A, Table 18.
9 Per the settlement proposal, updated to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Settlement Proposal, P. 18), expand the scope of the stretch factor to include asset service fees (Settlement Proposal, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding DRP (Settlement Proposal, P. 18). Supporting calculation is provided in PAO App. A, Table 7.
10 Updated to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the settlement proposal (Settlement Proposal, P. 19). See PAO App. D, Table 1, line 29.

Numbers may not add due to rounding.

Table 3

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

Line No.	Description	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D20 Project
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	10,624.7	(145.4)	10,479.3
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	(145.4)	11,116.9
	Capitalization				
5	**Short-term Debt**	3	56.4	(0.3)	56.1
6	**Long-Term Debt**	3	5,574.8	483.5	6,058.2
7	**Common Equity at ROE Rate**	3	5,631.2	(726.1)	4,905.0
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	(145.4)	11,116.9
	Cost of Capital				
10	**Short-term Debt**	3	3.6	(0.0)	3.6
11	**Long-Term Debt**	3	201.5	17.5	218.9
12	**Return on Equity at ROE Rate**	3	469.6	(60.6)	409.1
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	(39.6)	635.1
	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	(6.9)	570.3
18	**Property Tax**		13.6	0.0	13.6
19	**Total Expenses**		3,006.5	(76.1)	2,930.4
	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	(120.9)	3,539.7
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	18.6	10.6	29.2
26	**Revenue Requirement Net of Stretch Factor**		3,642.0	(131.5)	3,510.5
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	77.6	(19.2)	58.4
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,719.6	(150.7)	3,568.9

For notes see Table 3a.

Numbers may not add due to rounding.

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 Updated to reflect the settlement proposal reduction (Settlement Proposal, 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.

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

3 Updated to reflect the capital structure per the settlement proposal of 45% Equity : 55% Debt (Settlement Proposal, P. 24). 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 settlement proposal (Settlement Proposal, P. 23). See PAO App. A, Table 11 for supporting details.

5 Updated to reflect the 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 (Settlement Proposal, 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 Updated to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the settlement proposal (Settlement Proposal, P. 26) and the flow through impact of an upwards 0.7TWh adjustment to the nuclear production forecast per the settlement proposal (Settlement Proposal, 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) (Settlement Proposal, 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) (Settlement Proposal, 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 Updated to reflect a 10% increase in ancillary and other revenues forecast per the settlement proposal (Settlement Proposal, P. 27).

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

9 Per the settlement proposal, updated to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Settlement Proposal, P. 18), expand the scope of the stretch factor to include asset service fees (Settlement Proposal, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding DRP (Settlement Proposal, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Updated to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the settlement proposal (Settlement Proposal, P. 19). 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	Settlement Adjustment	Settled Amount Subject to D20 Project
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	11,887.5	(202.1)	11,685.4
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	(202.1)	12,269.4
	Capitalization				
5	**Short-term Debt**	3	57.9	(0.4)	57.5
6	**Long-Term Debt**	3	6,177.9	512.8	6,690.7
7	**Common Equity at ROE Rate**	3	6,235.8	(798.6)	5,437.2
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	(202.1)	12,269.4
	Cost of Capital				
10	**Short-term Debt**	3	4.0	(0.0)	3.9
11	**Long-Term Debt**	3	225.7	18.7	244.4
12	**Return on Equity at ROE Rate**	3	520.1	(66.6)	453.5
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	(44.8)	704.9
	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	(9.4)	510.8
18	**Property Tax**		12.7	0.0	12.7
19	**Total Expenses**		2,593.0	(76.5)	2,516.6
	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	(123.5)	3,227.9
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	25.5	14.4	39.9
26	**Revenue Requirement Net of Stretch Factor**		3,325.8	(137.8)	3,188.0
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	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	(137.8)	3,354.1

For notes see Table 4a.

Numbers may not add due to rounding.

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 Updated to reflect the settlement proposal reduction (Settlement Proposal, 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.
Supporting continuity schedules for resulting Net Fixed Asset rate base amounts are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the capital structure per the settlement proposal of 45% Equity : 55% Debt (Settlement Proposal, P. 24). 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 settlement proposal (Settlement Proposal, P. 23). See PAO App. A, Table 11 for supporting details.

5 Updated to reflect the 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 (Settlement Proposal, 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 Updated to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the settlement proposal (Settlement Proposal, P. 26) and the flow through impact of an upwards 0.9TWh adjustment to the nuclear production forecast per the settlement proposal (Settlement Proposal, 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) (Settlement Proposal, 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) (Settlement Proposal, 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 Updated to reflect a 10% increase in ancillary and other revenues forecast per the settlement proposal (Settlement Proposal, P. 27).

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

9 Per the settlement proposal, updated to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Settlement Proposal, P. 18), expand the scope of the stretch factor to include asset service fees (Settlement Proposal, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding DRP (Settlement Proposal, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Updated to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the settlement proposal (Settlement Proposal, P. 19). See PAO App. D, Table 1, line 29.

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	Settlement Adjustment	Settled Amount Subject to D20 Project
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	12,783.5	(247.2)	12,536.3
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	(247.2)	13,069.5
	Capitalization				
5	**Short-term Debt**	3	58.4	(0.4)	58.0
6	**Long-Term Debt**	3	6,599.9	530.3	7,130.2
7	**Common Equity at ROE Rate**	3	6,658.3	(850.0)	5,808.3
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	(247.2)	13,069.5
	Cost of Capital				
10	**Short-term Debt**	3	4.3	(0.0)	4.3
11	**Long-Term Debt**	3	241.2	19.4	260.6
12	**Return on Equity at ROE Rate**	3	555.3	(70.9)	484.4
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	(48.9)	751.9
	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	(11.8)	555.3
18	**Property Tax**		9.8	0.0	9.8
19	**Total Expenses**		1,811.0	(59.1)	1,752.0
	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	(114.3)	2,456.1
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	9	18.0	9.5	27.6
26	**Revenue Requirement Net of Stretch Factor**		2,552.4	(123.9)	2,428.5
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	10	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	(123.9)	2,594.7

For notes see Table 5a.

Numbers may not add due to rounding.

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 Updated to reflect the settlement proposal reduction (Settlement Proposal, 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.

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

3 Updated to reflect the capital structure per the settlement proposal of 45% Equity : 55% Debt (Settlement Proposal, P. 24). 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 settlement proposal (Settlement Proposal, P. 23). See PAO App. A, Table 11 for supporting details.

5 Updated to reflect the 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 (Settlement Proposal, 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 Updated to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per the settlement proposal (Settlement Proposal, P. 26) and the flow through impact of an upwards 0.4TWh adjustment to the nuclear production forecast per the settlement proposal (Settlement Proposal, 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) (Settlement Proposal, 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) (Settlement Proposal, 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 Updated to reflect a 10% increase in ancillary and other revenues forecast per the settlement proposal (Settlement Proposal, P. 27).

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

9 Per the settlement proposal, updated to increase the nuclear stretch factor to 0.6% for the years 2023-2025 (Settlement Proposal, P. 18), expand the scope of the stretch factor to include asset service fees (Settlement Proposal, P. 18), and apply the stretch factor to all capital-related revenue requirement excluding DRP (Settlement Proposal, P. 18). Supporting calculation is provided in PAO App. A, Table 7.

10 Updated to reflect a credit to customers for the nuclear facilities' portion of the COVID-19 related amounts per the settlement proposal (Settlement Proposal, P. 19). See PAO App. D, Table 1, line 29.

Numbers may not add due to rounding.

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**		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**		2.9	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.

Numbers may not add due to rounding.

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 App. A, Table 10 line 9, col. (e), plus PAO, App. A, Table 10, line 6, col. (e).
Line 1 (2023): PAO, App. A, Table 9, line 18, col. (f), less PAO, App. A., Table 9, line 15, col. (f), less App. A, Table 10, line 18, col. (e), plus PAO, App. A, Table 10, line 15, col. (e).
Line 1 (2024): PAO, App. A, Table 9, line 27 col. (f), less PAO, App. A., Table 9, line 24, col. (f), less App. A, Table 10, line 27, col. (e), plus PAO, App. A, Table 10, line 24, col. (e).
Line 1 (2025): PAO, App. A, Table 9, line 36, col. (f), less PAO, App. A., Table 9, line 33, col. (f), less App. A, Table 10, line 36, col. (e), plus PAO, App. A, Table 10, line 33, col .(e).
Line 1 (2026): PAO, App. A, Table 9, line 45, col. (f), less PAO, App. A., Table 9, line 42, col. (f), less App. A, Table 10 line 45, col. (e), plus PAO, App. A, Table 10, line 42, col. (e).

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.

Numbers may not add due to rounding.

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		132.9	153.0	166.3	178.8
15	Depreciation Expense	11		159.0	178.5	192.9	202.2
16	Income Tax Expense on Cost of Capital and Depreciation Expense	11		81.6	92.2	99.9	105.7
17	Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor (line 14 + line 15 + line 16)			373.5	423.7	459.1	486.7
	Pickering Capital Related Revenue Requirement						
18	Cost of Capital	12		8.5	4.4	2.2	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	26.4	0.6	0.0
21	Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor (line 18 + line 19 + line 20)			114.4	107.3	3.2	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)			2,490.8	2,381.7	2,038.9	1,404.2
24	Nuclear Stretch Factor	14		0.60%	0.60%	0.60%	0.30%
25	**Nuclear Stretch Factor Revenue Requirement Adjustment ($M)**	15		**14.9**	**29.2**	**39.9**	**27.6**

Notes:
Refer to Table 7a

Numbers may not add due to rounding.

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 (Settlement Proposal, 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 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 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 (Settlement Proposal, 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 8.34%)	82.2	94.7	103.5	112.3
(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))	**132.9**	**153.0**	**166.3**	**178.8**
(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))	244.9	276.7	299.6	317.1
(i)	Income Tax Expense (line (h) x 25% / (1 - 25%))	**81.6**	**92.2**	**99.9**	**105.7**

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

(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 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 8.34%)	5.4	2.8	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))	**8.5**	**4.4**	**2.2**	**-**
(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))	83.6	79.3	1.8	-
(i)	Income Tax Expense (line (h) x 25% / (1 - 25%))	**27.9**	**26.4**	**0.6**	**-**

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

(a)	Capital Cost Allowance & Other Deductions (PAO App. A, Tables 18-21, col. (c), line 14 less Darlington Refurbishment CCA per Ex. F4-2-1 Table 3c, note 3) plus other deductions	(305.7)	(276.2)	(300.2)	(287.7)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))	**(101.9)**	**(92.1)**	**(100.1)**	**(95.9)**

14 Per Settlement Proposal, 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	2.2	4.8	7.5	9.0
(f)	Pickering GS Capital Stretch Factor Adjustment Before CCA (line 21 x line 24) + Prior Year ++	0.7	1.3	1.3	-
(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))	14.9	29.2	39.9	27.6

+ 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.

Numbers may not add due to rounding.

Table 8
Summary of Settled Revenue Deficiency Subject to D2O Project - 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 ($M)**	3	3,511.7	3,425.9	3,510.5	3,188.0	2,428.5
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		497.7	624.8	460.7	399.3	463.1

Notes:
1 Production forecast per settlement proposal (Settlement Proposal 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).

Numbers may not add due to rounding.

Table 9
Continuity of Settled Property, Plant and Equipment Subject to D2O Project - 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)
			Note 1					
	2022 Plan:							
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)**		509.3	0.0	0.0	0.0	509.3	509.3
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**		11,828.0	442.7	(134.6)	308.1	12,136.0	11,861.0
8	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
9	**Total**		14,134.9	442.7	(134.6)	308.1	14,443.0	14,168.0
	2023 Plan:							
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)**		509.3	0.0	0.0	0.0	509.3	509.3
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**		12,136.0	439.1	0.0	439.1	12,575.1	12,383.5
17	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
18	**Total**		14,443.0	439.1	0.0	439.1	14,882.1	14,690.4
	2024 Plan:							
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)**		509.3	0.0	0.0	0.0	509.3	509.3
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**		12,575.1	2,963.6	0.0	2,963.6	15,538.8	15,364.9
26	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
27	**Total**		14,882.1	2,963.6	0.0	2,963.6	17,845.7	17,671.9
	2025 Plan:							
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)**		509.3	0.0	0.0	0.0	509.3	509.3
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**		15,538.8	2,368.0	0.0	2,368.0	17,906.8	17,111.6
35	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
36	**Total**		17,845.7	2,368.0	0.0	2,368.0	20,213.8	19,418.6
	2026 Plan:							
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)**		509.3	0.0	0.0	0.0	509.3	509.3
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**		17,906.8	2,360.7	0.0	2,360.7	20,267.4	18,495.5
44	**Asset Retirement Costs**		2,307.0	0.0	0.0	0.0	2,307.0	2,307.0
45	**Total**		20,213.8	2,360.7	0.0	2,360.7	22,574.4	20,802.5

For notes see Table 9a.

Numbers may not add due to rounding.

Table 9a
Notes to Table 9
Continuity of Settled Property, Plant and Equipment Subject to D2O Project - Nuclear ($M)

Notes:
1 Lines 1-5, 8, 10-14, 17, 19-23, 26, 28-32, 35, 37-41, 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 (Settlement Proposal 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

Numbers may not add due to rounding.

Table 10
Continuity of Settled Accumulated Depreciation and Amortization Subject to D2O Project - 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)
			Note 1				
	2022 Plan:						
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)**		45.9	15.0	0.0	60.9	53.4
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**		3,902.4	468.0	(34.8)	4,335.5	4,101.6
8	**Asset Retirement Costs**		2,023.9	82.2	0.0	2,106.1	2,065.0
9	**Total**		5,926.3	550.1	(34.8)	6,441.6	6,166.5
	2023 Plan:						
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)**		60.9	15.0	0.0	75.9	68.4
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**		4,335.5	415.4	0.0	4,750.9	4,543.2
17	**Asset Retirement Costs**		2,106.1	50.5	0.0	2,156.6	2,131.3
18	**Total**		6,441.6	465.9	0.0	6,907.5	6,674.5
	2024 Plan:						
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)**		75.9	15.0	0.0	90.8	83.3
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**		4,750.9	519.8	0.0	5,270.7	5,010.8
26	**Asset Retirement Costs**		2,156.6	50.5	0.0	2,207.1	2,181.8
27	**Total**		6,907.5	570.3	0.0	7,477.8	7,192.6
	2025 Plan:						
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)**		90.8	15.0	0.0	105.8	98.3
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**		5,270.7	507.2	0.0	5,777.9	5,524.3
35	**Asset Retirement Costs**		2,207.1	3.6	0.0	2,210.6	2,208.9
36	**Total**		7,477.8	510.8	0.0	7,988.6	7,733.2
	2026 Plan:						
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)**		105.8	15.0	0.0	120.8	113.3
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**		5,777.9	551.8	0.0	6,329.7	6,053.8
44	**Asset Retirement Costs**		2,210.6	3.6	0.0	2,214.2	2,212.4
45	**Total**		7,988.6	555.3	0.0	8,543.9	8,266.2

For notes see Table 10a.

Numbers may not add due to rounding.

Table 10a
Notes to Table 10
Continuity of Settled Accumulated Depreciation and Amortization Subject to D2O Project - Nuclear ($M)

Notes:

1 Lines 1-5, 8, 10-14, 17, 19-23, 26 per Ex. B3-4-1, Table 2. Lines 28-32, 35, 37-41, 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.

Numbers may not add due to rounding.

Table 11
Capitalization and Cost of Capital
Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
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	51.0	0.6%	0.47%	2.9
2	**Existing/Planned Long-Term Debt**	1, 2	2,010.0	23.3%	3.61%	72.5
3	**Other Long-Term Debt Provision**	1	2,677.9	31.1%	3.61%	96.5
4	**Total Debt**	3	4,738.9	55.0%	3.63%	171.9
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	3,748.4	43.5%	8.34%	312.6
5b	**Total Equity**	3	3,877.3	45.0%	8.18%	317.3
6	**Rate Base Financed by Capital Structure**	5	8,616.2	99.2%	5.68%	489.2
7	**Adjustment for Lesser of UNL or ARC**	1, 6	73.6	0.8%	4.89%	3.6
8	**Rate Base**	7	8,689.7	100%	5.67%	492.8

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 Settlement Proposal, 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 Settlement Proposal, 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 Settlement Proposal, 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 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).

Numbers may not add due to rounding.

Table 12
Capitalization and Cost of Capital
Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
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	50.6	0.6%	0.78%	3.0
2	**Existing/Planned Long-Term Debt**	1, 2	2,099.8	24.1%	3.49%	73.2
3	**Other Long-Term Debt Provision**	1	2,635.4	30.3%	3.49%	91.8
4	**Total Debt**	3	4,785.8	55.0%	3.51%	168.1
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	3,802.7	43.7%	8.34%	317.1
5b	**Total Equity**	3	3,915.7	45%	8.20%	321.1
6	**Rate Base Financed by Capital Structure**	5	8,701.5	100.0%	5.62%	489.1
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	8,701.5	100%	5.62%	489.1

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 Settlement Proposal, 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 Settlement Proposal, 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 Settlement Proposal, 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 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).

Numbers may not add due to rounding.

Table 13
Capitalization and Cost of Capital
Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
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	56.1	0.5%	1.16%	3.6
2	**Existing/Planned Long-Term Debt**	1, 2	2,168.5	19.5%	3.61%	78.4
3	**Other Long-Term Debt Provision**	1	3,889.7	35.0%	3.61%	140.6
4	**Total Debt**	3	6,114.3	55.0%	3.64%	222.5
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	4,905.0	44.1%	8.34%	409.1
5b	**Total Equity**	3	5,002.6	45%	8.25%	412.6
6	**Rate Base Financed by Capital Structure**	5	11,116.9	100.0%	5.71%	635.1
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	11,116.9	100%	5.71%	635.1

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 Settlement Proposal, 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 Settlement Proposal, 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 Settlement Proposal, 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 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).

Numbers may not add due to rounding.

Table 14
Capitalization and Cost of Capital
Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
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	57.5	0.5%	1.66%	3.9
2	**Existing/Planned Long-Term Debt**	1, 2	2,176.3	17.7%	3.65%	79.5
3	**Other Long-Term Debt Provision**	1	4,514.4	36.8%	3.65%	164.9
4	**Total Debt**	3	6,748.2	55.0%	3.68%	248.4
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	5,437.2	44.3%	8.34%	453.5
5b	**Total Equity**	3	5,521.2	45%	8.27%	456.5
6	**Rate Base Financed by Capital Structure**	5	12,269.4	100.0%	5.75%	704.9
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	12,269.4	100%	5.75%	704.9

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 Settlement Proposal, 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 Settlement Proposal, 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 Settlement Proposal, 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 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).

Numbers may not add due to rounding.

Table 15
Capitalization and Cost of Capital
Summary of Settled Nuclear Capitalization and Cost of Capital Subject to D2O Project
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	58.0	0.4%	2.23%	4.3
2	**Existing/Planned Long-Term Debt**	1, 2	2,192.0	16.8%	3.65%	80.1
3	**Other Long-Term Debt Provision**	1	4,938.2	37.8%	3.65%	180.5
4	**Total Debt**	3	7,188.2	55.0%	3.68%	264.9
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	5,808.3	44.4%	8.34%	484.4
5b	**Total Equity**	3	5,881.3	45%	8.28%	487.1
6	**Rate Base Financed by Capital Structure**	5	13,069.5	100.0%	5.75%	751.9
7	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**	7	13,069.5	100%	5.75%	751.9

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 Settlement Proposal, 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 Settlement Proposal, 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 Settlement Proposal, 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 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).

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

Numbers may not add due to rounding.

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 settlement proposal (Settlement Proposal, 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.

Numbers may not add due to rounding.

Table 17

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

Line No.	Particulars	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	236.7	(43.3)	193.4
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	553.0	(2.9)	550.1
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	(2.7)	1,275.3
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	839.5	(13.7)	825.8
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	(13.7)	1,621.2
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		(120.3)	(32.3)	(152.5)
24	**Tax Loss Carry-Over / (Applied)**	7	120.3	32.3	152.5
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.

Table 17a
Notes to Table 17
Calculation of Regulatory Income Taxes
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 Settled Amount Subject to D2O Project	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 1, line 12 and line 12a	360.6	(43.3)	317.3
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	(43.3)	362.8
4a	Additions for Regulatory Tax Purposes	line 13	1,278.0	(2.7)	1,275.3
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	(13.7)	1,621.2
7a		line 3a + line 4a - line 5a - line 6a	(103.7)	(32.3)	(136.0)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	(18.0)	(4.8)	(22.9)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	(12.0)	(3.2)	(15.3)
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)	(8.1)	(54.7)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	18.0	4.8	22.9
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	12.0	3.2	15.3
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	30.1	8.1	38.1
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	(43.3)	317.3
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	(43.3)	193.4

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 - 12a.
4 Settled Amounts from PAO App. A, Table 1, col. (c), line 17
5 Reflects the impact of updated 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 Adjustment to reflect changes to Capital Cost Allowance resulting from settlement adjustments to capital in-service additions per PAO App. A, Table 9a;13% reduction in forecast Nuclear Operations and 5% reduction in Corporate Support Services in-service additions.
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	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	236.0	(45.4)	190.5
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	471.5	(5.6)	465.9
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	(4.9)	1,206.1
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	878.8	(18.7)	860.1
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	(18.7)	1,510.5
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		(82.3)	(31.5)	(113.9)
24	**Tax Loss Carry-Over / (Applied)**	7	82.3	31.5	113.9
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.

Numbers may not add due to rounding.

Table 18a
Notes to Table 18
Calculation of Regulatory Income Taxes
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 Settled Amount Subject to D2O Project	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 2, line 12 and line 12a	366.5	(45.4)	321.1
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	(45.4)	359.8
4a	Additions for Regulatory Tax Purposes	line 13	1,210.9	(4.9)	1,206.1
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	(18.7)	1,510.5
7a		line 3a + line 4a - line 5a - line 6a	(66.0)	(31.5)	(97.5)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	(12.3)	(4.7)	(17.1)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	(8.2)	(3.2)	(11.4)
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)	(7.9)	(44.8)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	12.3	4.7	17.1
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	8.2	3.2	11.4
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	20.6	7.9	28.5
					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	(45.4)	321.1
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	(45.4)	190.5

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 - 12a.

4 Settled Amounts from PAO App. A, Table 2, col. (c), line 17
5 Reflects the impact of updated 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 Adjustment to reflect changes to Capital Cost Allowance resulting from settlement adjustments to capital in-service additions per PAO App. A, Table 9a;13% reduction in forecast Nuclear Operations and 5% reduction in Corporate Support Services in-service additions.
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.

Numbers may not add due to rounding.

Table 19

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

Line No.	Particulars	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	348.4	(57.0)	291.4
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	578.7	(8.4)	570.3
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	(7.2)	1,284.2
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	834.1	(20.3)	813.8
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	(20.3)	1,516.4
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		103.2	(43.9)	59.2
24	**Tax Loss Carry-Over / (Applied)**	7	(103.2)	43.9	(59.2)
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.

Numbers may not add due to rounding.

Table 19a
Notes to Table 19
Calculation of Regulatory Income Taxes
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 Settled Amount Subject to D2O Project	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 3, line 12 and line 12a	469.6	(57.0)	412.6
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	(57.0)	460.7
4a	Additions for Regulatory Tax Purposes	line 13	1,291.4	(7.2)	1,284.2
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	(20.3)	1,516.4
7a		line 3a + line 4a - line 5a - line 6a	119.6	(43.9)	75.6
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	15.5	(6.6)	8.9
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	10.3	(4.4)	5.9
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	(11.0)	(1.6)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(15.5)	6.6	(8.9)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(10.3)	4.4	(5.9)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(25.8)	11.0	(14.8)
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	(57.0)	412.6
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	(57.0)	291.4

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 - 12a.

4 Settled Amounts from PAO App. A, Table 3, col. (c), line 17
5 Reflects the impact of updated 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 Adjustment to reflect changes to Capital Cost Allowance resulting from settlement adjustments to capital in-service additions per PAO App. A, Table 9a;13% reduction in forecast Nuclear Operations and 5% reduction in Corporate Support Services in-service additions.

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.

Numbers may not add due to rounding.

Table 20

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

Line No.	Particulars	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	441.5	(63.4)	378.1
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	521.6	(10.9)	510.8
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	(10.3)	1,226.5
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	860.2	(24.3)	836.0
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	(24.3)	1,594.9
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		59.0	(49.4)	9.6
24	**Tax Loss Carry-Over / (Applied)**	7	(59.0)	49.4	(9.6)
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.

Numbers may not add due to rounding.

Table 20a
Notes to Table 20
Calculation of Regulatory Income Taxes
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 Settled Amount Subject to D2O Project	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 4, line 12 and line 12a	519.9	(63.4)	456.5
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	(63.4)	503.0
			0.0		
4a	Additions for Regulatory Tax Purposes	line 13	1,236.7	(10.3)	1,226.5
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	(24.3)	1,594.9
7a		line 3a + line 4a - line 5a - line 6a	75.2	(49.4)	25.8
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	8.9	(7.4)	1.4
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	5.9	(4.9)	1.0
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)	(12.4)	(13.7)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(8.9)	7.4	(1.4)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(5.9)	4.9	(1.0)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(14.8)	12.4	(2.4)
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	(63.4)	456.5
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	(63.4)	378.1

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 - 12a.
4 Settled Amounts from PAO App. A, Table 4, col. (c), line 17
5 Reflects the impact of updated 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 Adjustment to reflect changes to Capital Cost Allowance resulting from settlement adjustments to capital in-service additions per PAO App. A, Table 9a;13% reduction in forecast Nuclear Operations and 5% reduction in Corporate Support Services in-service additions.
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.

Numbers may not add due to rounding.

Table 21

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

Line No.	Particulars	Note	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2,3	468.7	(68.0)	400.6
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	568.6	(13.3)	555.3
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	(14.0)	1,391.3
	Deductions for Regulatory Tax Purposes:				
14	**CCA**	6	828.5	(24.6)	803.9
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	(24.6)	1,708.6
23	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 13 - line 22)		140.7	(57.5)	83.2
24	**Tax Loss Carry-Over / (Applied)**	7	(140.7)	57.5	(83.2)
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.

Numbers may not add due to rounding.

Table 21a
Notes to Table 21
Calculation of Regulatory Income Taxes
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 Settled Amount Subject to D2O Project	OPG Proposed	Settlement Adjustment	Settled Amount Subject to D2O Project
			(a)	(b)	(c)
			Note 2a		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 5, line 12 and line 12a	555.1	(68.0)	487.1
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	(68.0)	525.4
4a	Additions for Regulatory Tax Purposes	line 13	1,405.3	(14.0)	1,391.3
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	(24.6)	1,708.6
7a		line 3a + line 4a - line 5a - line 6a	156.6	(57.5)	99.2
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 28) x line 30/ (1 - line 32)	21.1	(8.6)	12.5
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 28) x line 31 / (1 - line 32)	14.1	(5.7)	8.3
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	(14.4)	4.9
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 24 x line 30	(21.1)	8.6	(12.5)
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 24 x line 31	(14.1)	5.7	(8.3)
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	(35.2)	14.4	(20.8)
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	(68.0)	487.1
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	(68.0)	400.6

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 - 12a.
4 Settled Amounts from PAO App. A, Table 5, col. (c), line 17
5 Reflects the impact of updated 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 Adjustment to reflect changes to Capital Cost Allowance resulting from settlement adjustments to capital in-service additions per PAO App. A, Table 9a;13% reduction in forecast Nuclear Operations and 5% reduction in Corporate Support Services in-service additions.
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.

Numbers may not add due to rounding.

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)	(473.6)	(587.5)	(528.3)	(518.6)
2	**Income/(Loss) for the Year**	2	(152.5)	(113.9)	0.0	0.0	0.0
3	**Tax Loss Applied**	2	0.0	0.0	59.2	9.6	83.2
4	**Loss Carried Forward** (line 1 + line 2 + line 3)		(473.6)	(587.5)	(528.3)	(518.6)	(435.4)

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 ($M)**	1	3,511.7	3,425.9	3,510.5	3,188.0	2,428.5
2	**Forecast Production (TWh)**	2	33.6	31.2	34.0	31.1	21.9
3	**Smoothed Nuclear Payment Amount ($/MWh)**	3	102.06	105.68	103.25	102.54	110.84
4	**Forecast Nuclear Revenue Received** (line 2 x line 3)		3,429.2	3,300.1	3,510.5	3,188.0	2,428.5
5	**Nuclear Revenue Requirement Deferred** (line 1 - line 4)		82.4	125.7	0.0	0.0	0.0

Notes:
1 PAO App. A, Tables 1 to 5, line 26, col. (c).
2 Per Settlement Proposal, 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	0.01	(0.04)	(0.37)	**0.18**
5	**Typical Bill Impact (%)** (line 4 / line 3)		0.90%	0.23%	0.01%	-0.03%	-0.32%	**0.16%**
6	Prior Year OPG Weighted Average Total Payments ($/MWh)	2	71.76	74.63	75.38	75.40	75.29	74.49
7	Current Year OPG Weighted Average Total Payments ($/MWh)	2	74.63	75.38	75.40	75.29	74.05	74.95
8	Change in OPG Weighted Average Total Payments ($/MWh) (line 7 - line 6)		2.87	0.75	0.02	(0.11)	(1.24)	0.46
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		2023		2024		2025		2026	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	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	0.02	0.02	(0.11)	(0.11)	(1.24)	(1.24)
7	**Percentage Increase in Consumer Bills**		0.87%	0.96%	0.22%	0.24%	0.01%	0.01%	-0.03%	-0.03%	-0.31%	-0.34%
	(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	0.92	31.39	(4.19)	(143.33)	(41.81)	(1,431.63)

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		2023		2024		2025		2026	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	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	0.02	0.02	(0.11)	(0.11)	(1.24)	(1.24)
7	**Percentage Increase in Consumer Bills**		0.64%	0.87%	0.16%	0.22%	0.01%	0.01%	-0.02%	-0.03%	-0.23%	-0.31%
	(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	0.42	18.29	(1.93)	(83.53)	(19.31)	(834.34)

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		2023		2024		2025		2026	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	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	0.02	0.02	(0.11)	(0.11)	(1.24)	(1.24)
7	**Percentage Increase in Consumer Bills**		0.83%	0.84%	0.21%	0.21%	0.01%	0.01%	-0.03%	-0.03%	-0.30%	-0.30%
	(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	0.90	46.08	(4.10)	(210.44)	(40.99)	(2,101.89)

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) ($/MWh)**	4	89.70	102.06	105.68	103.25	102.54	110.84
5	**Nuclear Payment Rider (NPR) ($/MWh)**	5	6.13	1.74	1.87	1.72	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	53.29	52.35	47.27
9	**Weighted Average Payment Amount ($/MWh)** ((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		71.76	74.63	75.38	75.40	75.29	74.05
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			4.0%	1.0%	0.0%	-0.1%	-1.7%

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. G.
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) = line 10 * (0.25 / 0.75). Tax rate from PAO App. A, Table 17, line 32, col. (c).
6 Calculated as: line 11 * tax rate / (1 - tax rate) = line 11 * (0.25 / 0.75). Tax rate from PAO App. A, Table 17, line 32, col. (c).
7 Calculated as: line 12 * tax rate / (1 - tax rate) = line 11 * (0.25 / 0.75). 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 settlement proposal (Settlement Proposal, 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 (Settlement Proposal, P. 28)
12 From Ex. H1-2-1, Table 1, col. (g) for lines 1-19.

Numbers may not add due to rounding.

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

Line No.	Account	Note	Audited Year End Balance 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											
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 Account**	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**		38.3	(17.4)	0.0	55.7	55.7	0.0		0.0	0.0	0.0	0.0	0.0	0.0	55.7
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**	14	(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	0.0	58.0	36	19.3	19.3	19.3	0.0	0.0	58.0	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	161.1	339.7		26.6	26.6	26.6	129.9	129.9	339.7	161.1
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	161.1	507.7		58.4	58.4	58.4	166.2	166.2	507.7	161.1
31	**Forecast Production (TWh)**	4								33.6	31.2	34.0	31.1	21.9		
32	**Nuclear Payment Rider ($/MWh)** (line 30 / line 31)									1.74	1.87	1.72	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 settlement proposal (Settlement Proposal, 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.
14 The final deferral and variance account amounts recoverable for the D2O Project and therefore the final nuclear payment riders are subject to the OEB's approval of OPG's proposed in-service amounts for the project, which are not subject to the settlement proposal.

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 17) 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 $339.7M (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)) 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 $507.7M (App. D, Table 1, col. (m), line 30).[1]

[1] Subject to any adjustments from the OEB's decision on the D2O Storage Project.

The OEB approves recovery of the above approved balances in the regulated hydroelectric deferral and variance accounts, together with the above additional amounts, using a payment rider 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 Appendix 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 a payment rider of $1.74/MWh from January 1, 2022 to December 31, 2022, $1.87/MWh from January 1, 2023 to December 31, 2023, $1.72/MWh from January 1, 2024 to December 31, 2024, $5.34/MWh from January 1, 2025 to December 31, 2025, and $7.58/MWh from January 1, 2026 to December 31, 2026, as determined in Appendix D, Table 1, line 32.[2]

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, being January 1, 2022.

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

[2] *Ibid*.

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 corresponding 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.[3]

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

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 nuclear revenue requirements approved by the OEB in 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.[4] 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 by the OEB 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.

[4] Ex. G2-1-1, Table 1, line 8, as increased by 10% as part of the settled amount of other revenues (Settlement Proposal, p. 29).

As detailed in EB-2013-0321, Ex. E1-2-1, Section 3.2 and set out in the EB-2016-0152 Payment Amounts Order[5], 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:

- 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)

[5] EB-2016-0152, Payment Amounts Order, Appendix G, p. 6.

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 annual 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.[6]

[6] 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, cols. (a) and (b), line 14).

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 requirements 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, ($1.36M) for 2023, ($1.37M) for 2024, ($1.34M) for 2025 and ($1.33M) for 2026, being 1/12 of the corresponding annual amounts reflected in the approved revenue requirements for 2022-2026.[7]

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 Section 6(2)4 of O. Reg. 53/05. 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.[8] 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

[7] Subject to any adjustments from the OEB's decision on the D2O Storage Project and the final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order.
[8] 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.

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 2021.[9] 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.[10] 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.[11] The monthly reference amounts for the DRP capital component shall be 1/12 of $442.2M for 2022, $417.5M for 2023, $700.0M for 2024, $842.5M for 2025, and $942.0M for 2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[12,13] 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

[9] This process is summarized at Ex. H1-1-1, Chart 1.
[10] Ex. F2-7-1, Table 1, line 1.
[11] Ex. L-H1-01-Staff-328, Chart 1, lines 4 and 9.
[12] The reference amount for the DRP capital component is equal to the revenue requirement impact of forecast DRP capital as presented at Ex. L-H1-01-Staff-328, Chart 2, updated for the settled capital structure (Settlement Proposal, pp. 28-29).
[13] Subject to any adjustments from the OEB's decision on the D2O Storage Project and the final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order.

2026, as reflected in the nuclear revenue requirements approved by the OEB in this proceeding.[14,15] 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;
- For the DRP capital component: $36.9M for 2022, $34.8M for 2023, $58.3M for 2024, $70.2M for 2025, and $78.5M for 2026; 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 amounts in (i).

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-2012 Additions component will have been fully amortized. OPG shall continue to track the Future Recovery

[14] 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 (Settlement Proposal, pp. 28-29).
[15] Subject to the final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order.

component separately until it is fully amortized by December 31, 2024, as previously approved by the OEB. [16]

As the nuclear 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, $272.8M in 2024, $228.2M in 2025, and $183.5M in 2026.[17] 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 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.[18] 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 requirement for 2014 and 2015 approved by the OEB in EB-2013-0321 and underpinning the approved hydroelectric payment amounts in this proceeding reflects forecast registered pension plan ("RPP") contributions and OPEB plan payments (including the long-term disability benefit plan), rather than pension and OPEB costs calculated on an accrual basis.

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

[16] 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)
[17] Ex. F4-3-2, Chart 1.
[18] Income tax PILs impacts are determined by multiplying additions to and deductions from regulatory earnings before tax related to pension and OPEB plans (Appendix A, Tables 17-21, col. (c): line 5 less line 17 less line 18) by 25% / (1 - 25%).

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 Northern Development, Mines, Natural Resources and Forestry, pertaining to production increases at OPG's Sir 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[19] 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

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

annual average forecast of $12.8M[20] 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 nuclear revenue requirements in this proceeding reflect pension and OPEB costs calculated on an accrual basis, rather than RPP contributions and OPEB plan payments.

2.11 Pension & 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 that period included RPP contributions and OPEB plan payments, rather than 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 shall be recorded on the balance in the account.

[20] Ex. H1-1-1, Table 7, line 2 and EB-2016-0152, Payment Amounts Order, Appendix G, p. 12.

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[21] 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 & 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 & 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 Primary 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 double entry book-keeping, for each of regulated hydroelectric and nuclear facilities. Carrying charges do not apply to the Contra Sub-Account. The Carrying

[21] 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.

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 $28.0M ordered in EB-2013-0321 and the varied disallowance of $6.4M 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.[22] 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%.[23] As the average unfunded nuclear liabilities are negative and lesser than the average asset retirement cost beginning in 2023, OPG shall record the return on rate base in

[22] O. Reg. 53/05 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).
[23] Appendix A, Table 11, line 7, col. (c).

the account beginning in 2023 using the OEB-approved weighted average cost of capital rates.[24]

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. Subject to the OEB's decision on the scope of the account as it relates to small modular reactors, this account shall continue to record variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB. Such monthly reference amount shall be $2.2M in 2022, $2.2M in 2023, $2.3M in 2024, 2.3M in 2025 and $2.3M in 2026, being 1/12 of the corresponding annual amounts of $0.18M, $0.18M, $0.19M, $0.19M, $0.19M reflected in the approved nuclear revenue requirements for 2022-2026.[25]

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

[24] Appendix A, Tables 12-15: line 4, col. (b) x col. (c) + line 5b, col. (b) x line 5a, col. (c).
[25] Ex. F2-1-1, Table 1, line 6, cols. (g) to (k).

Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations.

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 nuclear revenue requirements approved by the OEB for each respective year from 2022 to 2026[26] 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[27] ("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.[28] 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.

[26] Appendix A, Tables 1-5, line 20, col. (c).
[27] Appendix A, Table 8, line 1.
[28] 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.[29] 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 on the balance 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 nuclear revenue requirements 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.[30] 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.

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

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 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, and 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 Section 5.5(1) of O. Reg. 53/05, an annual deferral amount will be recorded in this account from January 1, 2017 until the DRP ends (the "deferral period").[31] 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, $0.0M in 2024, $0.0M in 2025, and $0.0M in 2026.[32]

Per Section 5.5(2) of O. Reg. 53/05, 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.[33]

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[31] O. Reg. 53/05 specifies that the balance recorded in the account is to be recovered on a straight line basis over a period not to exceed ten years commencing at the end of the deferral period (subsection 6(2)12(iv)).

[32] Subject to any adjustments from the OEB's decision on the D2O Storage Project, the final ROE rate as specified by the OEB's Cost of Capital Report as of the effective date of the final payment amounts order,and any adjustments to the rate smoothing proposal as part the process of establishing the final payment amounts order.

[33] Long-term debt rates for 2022-2026 are presented at Appendix A, Tables 11-15: line 2, col. (c).

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.[34] 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.

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.

[34] Ex. L-H1-01-Energy Probe-068.

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

Basis of Approval

OEB Approved Settlement Proposal, p. 33.

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.[1]

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.

[1] 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 the EB-2020-0290 proceeding.

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: (i) are eligible for reimbursement to OPG under the Ontario Nuclear Funds Agreement; (ii) have already been included in an order made by the OEB.

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.

O. Reg. 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

OEB Approved Settlement Proposal, p. 33.

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

OEB Approved Settlement Proposal, p. 33.

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.[2] 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 include the balance tracked in the account as part of its reporting requirements for deferral and variance accounts.

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

[2] 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

OEB Approved Settlement Proposal, p. 33.

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[3] for the regulated hydroelectric facilities and the ROE rate approved in EB-2020-0290[4] 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.

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

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

Basis of Approval

OEB Approved Settlement Proposal, p. 33.

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.

Updated July 16 2021

EB-2020-0290
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2020-0290 Revenue Requirement Work Form

Table of Contents

Worksheet

No.

1 Cover Page

2 Table of Contents

3 Legend / Colour Scheme

4 OEB Adjustment Input Sheet

5 Rate Base and Cost of Capital

6 Regulatory Income Taxes

7 Revenue Requirement

8 Revenue Requiremenmt Deficiency / Sufficiency

9 Requested Payment Amounts

10 Recovery of Deferral and Variance Accounts and Riders

11 Residential Customer Impacts

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

Ontario Power Generation

EB-2020-0290 Revenue Requirement Work Form

Legend / Colour Scheme

OPG Proposed Amounts

Adjustment Input Cells For OEB Use

Automatically Generated Calculations

OEB Adjustment Input Sheet

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

Total Generating Facilities

Line No.	Description	2022 OPG Proposed 12/31/2020	2022 Settlement Agreement	2022 OEB Adjustment	2022 OEB Approved	2023 OPG Proposed 12/31/2020	2023 Settlement Agreement	2023 OEB Adjustment	2023 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Capital Structure									
1	Common Equity	50.0%	44.2%		44.2%	50.0%	44.3%		44.3%
2	Common Equity at Long Term Rate		0.8%		0.8%		0.7%		0.7%
3	Debt	50.0%	55.0%		55.0%	50.0%	55.0%		55.0%
Cost of Capital									
4	Short-Term Debt Facility Cost ($M)	5.2	5.2		5.2	5.2	5.2		5.2
5	Short-Term Debt Interest Cost ($M)	0.5	0.5		0.5	0.8	0.8		0.8
6	Regulated Portion of Short-Term Debt Allocation Factor	97.40%	97.40%		97.40%	97.40%	97.40%		97.40%
7	Short-Term Debt Cost ($M)	5.5	5.5		5.5	5.8	5.8		5.8
8	Regulated Portion of Short-Term Debt Cost Rate	0.47%	0.47%		0.47%	0.78%	0.78%		0.78%
9	Existing and Planned Long-Term Debt Cost Rate	3.61%	3.61%		3.61%	3.49%	3.49%		3.49%
10	Other Long-Term Debt Provision Cost Rate	3.61%	3.61%		3.61%	3.49%	3.49%		3.49%
11	Common Equity Cost Rate ROE	8.34%	8.34%		8.34%	8.34%	8.34%		8.34%
13	Adjustment for Lesser of UNL/ARC Cost Rate	4.89%	4.89%		4.89%	4.89%	4.89%		4.89%
Capitalization ($M)									
14	Short-Term Debt Principal	97.4	97.4		97.4	97.4	97.4		97.4
15	Existing and Planned Long-Term Debt Principal	3,837.8	3,837.8		3,837.8	4,039.6	4,039.6		4,039.6
16	Common Equity at OEB Approved Rate		7,274.3		7,274.3		7,419.8		7,419.8
17	Common Equity at Long Term Rate		128.8		128.8		113.0		113.0
18	Adjustment for Lesser of UNL/ARC	73.6	73.6		73.6	-	-		-

Line No.	Description	2024 OPG Proposed 12/31/2020	2024 Settlement Agreement	2024 OEB Adjustment	2024 OEB Approved	2025 OPG Proposed 12/31/2020	2025 Settlement Agreement	2025 OEB Adjustment	2025 OEB Approved	2026 OPG Proposed 12/31/2020	2026 Settlement Agreement	2026 OEB Adjustment	2026 OEB Approved
		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Capital Structure													
1	Common Equity	50.0%	44.5%		44.5%	50.0%	44.6%		44.6%	50.0%	44.7%		44.7%
2	Common Equity at Long Term Rate		0.5%		0.5%		0.4%		0.4%		0.3%		0.3%
3	Debt	50.0%	55.0%		55.0%	50.0%	55.0%		55.0%	50.0%	55.0%		55.0%
Cost of Capital													
4	Short-Term Debt Facility Cost ($M)	5.2	5.2		5.2	5.2	5.2		5.2	5.2	5.2		5.2
5	Short-Term Debt Interest Cost ($M)	1.2	1.2		1.2	1.7	1.7		1.7	2.2	2.2		2.2
6	Regulated Portion of Short-Term Debt Allocation Factor	97.40%	97.40%		97.40%	97.40%	97.40%		97.40%	97.40%	97.40%		97.40%
7	Short-Term Debt Cost ($M)	6.2	6.2		6.2	6.7	6.7		6.7	7.2	7.2		7.2
8	Regulated Portion of Short-Term Debt Cost Rate	1.16%	1.16%		1.16%	1.66%	1.66%		1.66%	2.23%	2.23%		2.23%
9	Existing and Planned Long-Term Debt Cost Rate	3.61%	3.61%		3.61%	3.65%	3.65%		3.65%	3.65%	3.65%		3.65%
10	Other Long-Term Debt Provision Cost Rate	3.61%	3.61%		3.61%	3.65%	3.65%		3.65%	3.65%	3.65%		3.65%
11	Common Equity Cost Rate ROE	8.34%	8.34%		8.34%	8.34%	8.34%		8.34%	8.34%	8.34%		8.34%
13	Adjustment for Lesser of UNL/ARC Cost Rate	4.89%	4.89%		4.89%	4.89%	4.89%		4.89%	4.89%	4.89%		4.89%
Capitalization ($M)													
14	Short-Term Debt Principal	97.4	97.4		97.4	97.4	97.4		97.4	97.4	97.4		97.4
15	Existing and Planned Long-Term Debt Principal	3,764.6	3,764.6		3,764.6	3,686.2	3,686.2		3,686.2	3,680.9	3,680.9		3,680.9
16	Common Equity at OEB Approved Rate		8,587.0		8,587.0		9,267.8		9,267.8		9,803.2		9,803.2
17	Common Equity at Long Term Rate		97.6		97.6		84.1		84.1		73.0		73.0
18	Adjustment for Lesser of UNL/ARC	-	-		-	-	-		-	-	-		-

Nuclear Facilities

Line No.	Description	2022 OPG Proposed 12/31/2020	2022 Settlement Agreement	2022 OEB Adjustment	2022 OEB Approved	2023 OPG Proposed 12/31/2020	2023 Settlement Agreement	2023 OEB Adjustment	2023 OEB Approved
	Rate Base ($M)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
19	Gross Plant at Cost	14,197.9	14,168.0		14,168.0	14,781.3	14,690.4		14,690.4
20	Accumulated Depreciation/Amortization	6,165.8	6,166.5		6,166.5	6,678.1	6,674.5		6,674.5
21	Cash Working Capital	(37.8)	(37.8)		(37.8)	(37.8)	(37.8)		(37.8)
22	Materials and Supplies	517.3	517.3		517.3	513.5	513.5		513.5
23	Nuclear Fuel Inventory	208.7	208.7		208.7	209.8	209.8		209.8
24	**Total**	**8,720.4**	**8,689.7**	**-**	**8,689.7**	**8,788.7**	**8,701.5**	**-**	**8,701.5**
	Expenses ($M)								
25	OM&A	2,341.2	2,276.2		2,276.2	2,382.0	2,315.0		2,315.0
26	Fuel	178.3	177.3		177.3	182.1	181.2		181.2
27	Depreciation/Amortization	553.0	550.1		550.1	471.5	465.9		465.9
28	Property Taxes	12.9	12.9		12.9	13.2	13.2		13.2
29	**Total**	**3,085.4**	**3,016.5**	**-**	**3,016.5**	**3,049.0**	**2,975.4**	**-**	**2,975.4**
	Other Revenues ($M)								
30	Bruce Lease Revenues Net of Direct Costs	(45.6)	(45.6)		(45.6)	(38.7)	(38.7)		(38.7)
31	Ancillary and Other Revenue	24.2	26.6		26.6	41.9	46.1		46.1
32	**Total**	**(21.4)**	**(19.0)**	**-**	**(19.0)**	**3.2**	**7.4**	**-**	**7.4**
33	**Forecast Production** (TWh)	**33.2**	**33.6**		**33.6**	**30.8**	**31.2**		**31.2**

Line No.	Description	2024 OPG Proposed 12/31/2020	2024 Settlement Agreement	2024 OEB Adjustment	2024 OEB Approved	2025 OPG Proposed 12/31/2020	2025 Settlement Agreement	2025 OEB Adjustment	2025 OEB Approved	2026 OPG Proposed 12/31/2020	2026 Settlement Agreement	2026 OEB Adjustment	2026 OEB Approved
		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
19	Gross Plant at Cost	17,826.3	17,671.9		17,671.9	19,637.9	19,418.6		19,418.6	21,077.4	20,802.5		20,802.5
20	Accumulated Depreciation/Amortization	7,203.2	7,192.6		7,192.6	7,753.4	7,733.2		7,733.2	8,298.6	8,266.2		8,266.2
21	Cash Working Capital	(37.8)	(37.8)		(37.8)	(37.8)	(37.8)		(37.8)	(37.8)	(37.8)		(37.8)
22	Materials and Supplies	485.6	485.6		485.6	435.9	435.9		435.9	392.5	392.5		392.5
23	Nuclear Fuel Inventory	189.8	189.8		189.8	185.9	185.9		185.9	178.5	178.5		178.5
24	**Total**	**11,260.7**	**11,116.9**	**-**	**11,116.9**	**12,468.5**	**12,269.4**	**-**	**12,269.4**	**13,312.0**	**13,069.5**	**-**	**13,069.5**
	Expenses ($M)												
25	OM&A	2,207.1	2,137.0		2,137.0	1,869.0	1,803.3		1,803.3	1,083.3	1,038.9		1,038.9
26	Fuel	209.4	209.5		209.5	188.6	189.9		189.9	148.2	148.0		148.0
27	Depreciation/Amortization	578.7	570.3		570.3	521.6	510.8		510.8	568.6	555.3		555.3
28	Property Taxes	13.6	13.6		13.6	12.7	12.7		12.7	9.8	9.8		9.8
29	**Total**	**3,008.8**	**2,930.4**	**-**	**2,930.4**	**2,591.9**	**2,516.6**	**-**	**2,516.6**	**1,809.8**	**1,752.0**	**-**	**1,752.0**
	Other Revenues ($M)												
30	Bruce Lease Revenues Net of Direct Costs	(48.1)	(48.1)		(48.1)	(46.5)	(46.5)		(46.5)	(38.3)	(38.3)		(38.3)
31	Ancillary and Other Revenue	52.3	57.5		57.5	21.8	24.0		24.0	63.8	70.2		70.2
32	**Total**	**4.2**	**9.4**	**-**	**9.4**	**(24.7)**	**(22.5)**	**-**	**(22.5)**	**25.5**	**31.9**	**-**	**31.9**
33	**Forecast Production** (TWh)	**33.3**	**34.0**		**34.0**	**30.2**	**31.1**		**31.1**	**21.5**	**21.9**		**21.9**

OEB Adjustment Input Sheet

Line No.	Description	Nuclear Facilities																			
		2022				2023				2024				2025				2026			
		OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	©	(d)	€	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
Applicable Tax Rates																					
34	Federal Rate	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%
35	Provincial Rate	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%
36		**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**
Tax Credits and Payment Adjustments ($M)																					
37	SR&ED Investment	(16.5)	(16.5)		(16.5)	(16.3)	(16.3)		(16.3)	(16.4)	(16.4)		(16.4)	(16.1)	(16.1)		(16.1)	(15.9)	(15.9)		(15.9)
Taxable Income Adjustments ($M)																					
	Additions																				
38	Depreciation and Amortization	553.0	550.1		550.1	471.5	465.9		465.9	578.7	570.3		570.3	521.6	510.8		510.8	568.6	555.3		555.3
39	Nuclear Waste Management Expenses	57.3	57.3		57.3	68.9	68.9		68.9	72.3	72.3		72.3	52.1	52.1		52.1	47.1	47.1		47.1
40	Receipts from Nuclear Segregated Funds	82.5	82.5		82.5	104.3	104.3		104.3	136.4	136.4		136.4	284.2	284.2		284.2	529.3	529.3		529.3
41	Pension and OPEB Accrual	311.7	311.7		311.7	294.1	294.1		294.1	272.8	272.8		272.8	228.2	228.2		228.2	182.6	183.5		183.5
42	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account	28.0	28.7		28.7	28.0	28.7		28.7	28.0	28.7		28.7	21.1	21.1		21.1	21.1	21.1		21.1
43	Regulatory Asset Amortization - Pension and OPEB Variance Cash vs Accrual	152.7	152.9		152.9	152.7	152.9		152.9	152.7	152.9		152.9	108.8	108.8		108.8	108.8	108.8		108.8
44	Regulatory Liability Amortization - Income and Other Taxes Variance Account	(1.6)	(1.6)		(1.6)	(1.6)	(1.6)		(1.6)	(1.6)	(1.6)		(1.6)	-	-		-	-	-		-
45	Adjustment Related to Financing Cost for Nuclear Liabilities	3.6	3.6		3.6	-	-		-	-	-		-	-	-		-	-	-		-
46	Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion	17.4	17.4		17.4	16.5	16.5		16.5	16.3	16.3		16.3	16.3	16.3		16.3	16.1	16.1		16.1
47	Other	73.2	72.6		72.6	76.2	76.3		76.3	35.5	36.0		36.0	4.4	5.0		5.0	(69.3)	(70.0)		(70.0)
48	**Total Additions**	**1,277.8**	**1,275.3**	**-**	**1,275.3**	**1,210.7**	**1,206.1**	**-**	**1,206.1**	**1,291.2**	**1,284.2**	**-**	**1,284.2**	**1,236.7**	**1,226.5**	**-**	**1,226.5**	**1,404.4**	**1,391.3**	**-**	**1,391.3**
	Deductions																				
49	CCA	839.5	825.8		825.8	878.8	860.1		860.1	834.1	813.8		813.8	860.2	836.0		836.0	828.5	803.9		803.9
50	Cash Expenditures for Nuclear Waste & Decomissioning	269.6	269.6		269.6	262.7	262.7		262.7	306.1	306.1		306.1	463.9	463.9		463.9	638.4	638.4		638.4
51	Contributions to Nuclear Segregated Funds and Earnings	244.4	244.4		244.4	100.6	100.6		100.6	100.6	100.6		100.6	-	-		-	-	-		-
52	Pension Plan Contributions	148.5	148.5		148.5	151.5	151.5		151.5	152.1	152.1		152.1	151.7	151.7		151.7	123.0	123.0		123.0
53	OPEB Payments	98.0	98.0		98.0	101.4	101.4		101.4	103.2	103.2		103.2	103.8	103.8		103.8	104.2	104.2		104.2
54	Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
55	Deductible SR&ED Qualifying Expenditures	35.0	35.0		35.0	34.2	34.2		34.2	34.4	34.4		34.4	33.1	33.1		33.1	32.3	32.3		32.3
56	Other	-	-		-	-	-		-	6.1	6.1		6.1	6.3	6.3		6.3	6.9	6.9		6.9
57	**Total Deductions**	**1,634.9**	**1,621.2**	**-**	**1,621.2**	**1,529.2**	**1,510.5**	**-**	**1,510.5**	**1,536.7**	**1,516.4**	**-**	**1,516.4**	**1,619.2**	**1,594.9**	**-**	**1,594.9**	**1,733.2**	**1,708.6**	**-**	**1,708.6**

OEB Adjustment Input Sheet

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

Line No.	Description	Deferral Accounts 2022 OPG Proposed 12/31/2020	2022 Settlement Agreement	2022 OEB Adjustment	2022 OEB Approved	2023 OPG Proposed 12/31/2020	2023 Settlement Agreement	2023 OEB Adjustment	2023 OEB Approved	2024 OPG Proposed 12/31/2020	2024 Settlement Agreement	2024 OEB Adjustment	2024 OEB Approved	2025 OPG Proposed 12/31/2020	2025 Settlement Agreement	2025 OEB Adjustment	2025 OEB Approved	2026 OPG Proposed 12/31/2020	2026 Settlement Agreement	2026 OEB Adjustment	2026 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
Hydroelectric Facilities ($M)																					
1	Hydroelectric Water Conditions Variance	(36.4)	(36.4)		(36.4)	(36.4)	(36.4)		(36.4)	(36.4)	(36.4)		(36.4)	-	-		-	-	-		-
2	Ancillary Services Net Revenue Variance - Hydroelectric	(11.1)	(11.1)		(11.1)	(11.1)	(11.1)		(11.1)	(11.1)	(11.1)		(11.1)	-	-		-	-	-		-
3	Hydroelectric Incentive Mechanism Variance	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	-	-		-	-	-		-
4	Hydroelectric Surplus Baseload Generation Variance	69.4	56.1		56.1	69.4	56.1		56.1	69.4	56.1		56.1	-	-		-	-	-		-
5	Income and Other Taxes Variance - Hydroelectric	(0.9)	(0.9)		(0.9)	(0.9)	(0.9)		(0.9)	(0.9)	(0.9)		(0.9)	-	-		-	-	-		-
6	Capacity Refurbishment Variance - Hydroelectric	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	1.3	1.3		1.3	1.3	1.3		1.3	1.3	1.3		1.3	-	-		-	-	-		-
8	Pension and OPEB Cost Variance - Hydroelectric - Future	1.1	1.1		1.1	1.1	1.1		1.1	1.1	1.1		1.1	-	-		-	-	-		-
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
10	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved	8.3	8.3		8.3	8.3	8.3		8.3	8.3	8.3		8.3	8.3	8.3		8.3	8.3	8.3		8.3
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non - RPP - EB-2018-0243 Approved	7.0	7.0		7.0	7.0	7.0		7.0	7.0	7.0		7.0	-	-		-	-	-		-
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions	8.8	8.8		8.8	8.8	8.8		8.8	8.8	8.8		8.8	8.8	8.8		8.8	8.8	8.8		8.8
13	Pension & OPEB Cash Payment Variance - Hydroelectric	(12.9)	(12.9)		(12.9)	(12.9)	(12.9)		(12.9)	(12.9)	(12.9)		(12.9)	-	-		-	-	-		-
14	Pension and OPEB Cash Versus Accrual Differential Carrying Charges - Hydroelectric	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)	-	-		-	-	-		-
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance	1.1	1.1		1.1	1.1	1.1		1.1	1.1	1.1		1.1	-	-		-	-	-		-
16	**Total**	35.7	22.4		22.4	35.7	22.4		22.4	35.7	22.4		22.4	17.1	17.1		17.1	17.1	17.1		17.1
17	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - RPP - EB-2018-0243 Approved	2.8	2.8		2.8	2.8	2.8		2.8	2.8	2.8		2.8	2.8	2.8		2.8	2.8	2.8		2.8
18	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non RPP - EB-2018-0243 Approved	2.3	2.3		2.3	2.3	2.3		2.3	2.3	2.3		2.3	-	-		-	-	-		-
19	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions	2.9	2.9		2.9	2.9	2.9		2.9	2.9	2.9		2.9	2.9	2.9		2.9	2.9	2.9		2.9
20	Settlement Agreement Covid-19 Impacts		3.6		3.6		3.6		3.6		3.6		3.6		-		-		-		-
21	**Total Recoverable Amount**	**43.7**	**34.0**		**34.0**	**43.7**	**34.0**		**34.0**	**43.7**	**34.0**		**34.0**	**22.8**	**22.8**		**22.8**	**22.8**	**22.8**		**22.8**
									-												
Nuclear Facilities ($M)									-												
22	Nuclear Liability Deferral	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
23	Impact Resulting from Changes in Station End-of-Life Dates (Dec 31, 2015) Deferral Acco	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
24	Nuclear Development Variance	1.2	1.2		1.2	1.2	1.2		1.2	1.2	1.2		1.2	-	-		-	-	-		-
25	Ancillary Services Net Revenue Variance - Nuclear	(1.2)	(1.2)		(1.2)	(1.2)	(1.2)		(1.2)	(1.2)	(1.2)		(1.2)	-	-		-	-	-		-
26	Capacity Refurbishment Variance - Nuclear - DRP	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
27	Capacity Refurbishment Variance - Nuclear - Non-DRP	(34.3)	(32.0)		(32.0)	(34.3)	(32.0)		(32.0)	(34.3)	(32.0)		(32.0)	-	-		-	-	-		-
28	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA-DRP	(6.4)	(6.4)		(6.4)	(6.4)	(6.4)		(6.4)	(6.4)	(6.4)		(6.4)	-	-		-	-	-		-
29	Capacity Refurbishment Variance - Nuclear - D2O	19.4	19.3		19.3	19.4	19.3		19.3	19.4	19.3		19.3	-	-		-	-	-		-
30	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(0.7)	-		-	(0.7)	-		-	(0.7)	-		-	-	-		-	-	-		-
31	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243 Approved	21.1	21.1		21.1	21.1	21.1		21.1	21.1	21.1		21.1	21.1	21.1		21.1	21.1	21.1		21.1
32	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post-2017 Additions	7.7	7.7		7.7	7.7	7.7		7.7	7.7	7.7		7.7	-	-		-	-	-		-
33	Income and Other Taxes Variance - Nuclear	(4.8)	(4.8)		(4.8)	(4.8)	(4.8)		(4.8)	(4.8)	(4.8)		(4.8)	-	-		-	-	-		-
34	Pension and OPEB Cost Variance - Nuclear - Future	21.5	21.5		21.5	21.5	21.5		21.5	21.5	21.5		21.5	-	-		-	-	-		-
35	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
36	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved	53.2	53.2		53.2	53.2	53.2		53.2	53.2	53.2		53.2	53.2	53.2		53.2	53.2	53.2		53.2
37	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non - RPP - EB-2018-0243 Approved	44.1	44.1		44.1	44.1	44.1		44.1	44.1	44.1		44.1	-	-		-	-	-		-
38	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions	55.6	55.6		55.6	55.6	55.6		55.6	55.6	55.6		55.6	55.6	55.6		55.6	55.6	55.6		55.6
39	Pension & OPEB Cash Payment Variance - Nuclear	(58.1)	(58.1)		(58.1)	(58.1)	(58.1)		(58.1)	(58.1)	(58.1)		(58.1)	-	-		-	-	-		-
40	Pension and OPEB Cash Versus Accrual Differential Carrying Charges - Nuclear	(0.2)	(0.2)		(0.2)	(0.2)	(0.2)		(0.2)	(0.2)	(0.2)		(0.2)	-	-		-	-	-		-
41	Nuclear Deferral and Variance Over/Under Recovery Variance	(7.7)	(8.4)		(8.4)	(7.7)	(8.4)		(8.4)	(7.7)	(8.4)		(8.4)	-	-		-	-	-		-
42	Fitness for Duty Deferral	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
43	SR&ED ITC Variance	(4.0)	(4.0)		(4.0)	(4.0)	(4.0)		(4.0)	(4.0)	(4.0)		(4.0)	-	-		-	-	-		-
44	Rate Smoothing Deferral	-	-		-	-	-		-	-	-		-	-	-		-	-	-		-
45	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	(81.9)	(81.9)		(81.9)	(81.9)	(81.9)		(81.9)	(81.9)	(81.9)		(81.9)	-	-		-	-	-		-
46	Total	24.4	26.6		26.6	24.4	26.6		26.6	24.4	26.6		26.6	129.9	129.9		129.9	129.9	129.9		129.9
47	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - RPP - EB-2018-0243 Approved	17.7	17.7		17.7	17.7	17.7		17.7	17.7	17.7		17.7	17.7	17.7		17.7	17.7	17.7		17.7
48	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non RPP - EB-2018-0243 Approved	14.7	14.7		14.7	14.7	14.7		14.7	14.7	14.7		14.7	-	-		-	-	-		-
49	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions	18.5	18.5		18.5	18.5	18.5		18.5	18.5	18.5		18.5	18.5	18.5		18.5	18.5	18.5		18.5
50	Settlement Agreement Covid 19-Impacts		(19.2)		(19.2)		(19.2)		(19.2)		(19.2)		(19.2)		-		-		-		-
51	**Total Recoverable Amount**	**75.4**	**58.4**		**58.4**	**75.4**	**58.4**		**58.4**	**75.4**	**58.4**		**58.4**	**166.2**	**166.2**		**166.2**	**166.2**	**166.2**		**166.2**

OPG Rate Base and Cost of Capital

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

		Total Generating Facilities				Nuclear Facilities															
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
1	Nuclear Rate Base Financed by Capital Structure ($M)	8,646.8	8,616.2	-	8,616.2	8,788.7	8,701.5	-	8,701.5	11,260.7	11,116.9	-	11,116.9	12,468.5	12,269.4	-	12,269.4	13,312.0	13,069.5	-	13,069.5
2	Nuclear Allocation Factor	52.46%	52.37%		52.37%	52.23%	51.98%		51.98%	57.92%	57.60%		57.60%	59.43%	59.04%		59.04%	59.99%	59.55%		59.55%

		Nuclear Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
Capitalization ($M)																					
3	Total Rate Base	8,720.4	8,689.7	-	8,689.7	8,788.7	8,701.5	-	8,701.5	11,260.7	11,116.9	-	11,116.9	12,468.5	12,269.4	-	12,269.4	13,312.0	13,069.5	-	13,069.5
4	Adjustment for Lesser of UNL/ARC	73.6	73.6	-	73.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Rate Base Financed by Capital Structure**	**8,646.8**	**8,616.2**	**-**	**8,616.2**	**8,788.7**	**8,701.5**	**-**	**8,701.5**	**11,260.7**	**11,116.9**	**-**	**11,116.9**	**12,468.5**	**12,269.4**	**-**	**12,269.4**	**13,312.0**	**13,069.5**	**-**	**13,069.5**
6	**Common Equity Subject to OEB Approved ROE**	**4,323.4**	**3,748.4**	**-**	**3,748.4**	**4,394.4**	**3,802.7**	**-**	**3,802.7**	**5,630.4**	**4,905.0**	**-**	**4,905.0**	**6,234.2**	**5,437.2**	**-**	**5,437.2**	**6,656.0**	**5,808.3**	**-**	**5,808.3**
7	**Common Equity Subject to Long Term Rate**		**128.8**	**-**	**128.8**		**113.0**	**-**	**113.0**		**97.6**	**-**	**97.6**		**84.1**	**-**	**84.1**		**73.0**	**-**	**73.0**
8	Total Debt	4,323.4	4,738.9	-	4,738.9	4,394.4	4,785.8	-	4,785.8	5,630.4	6,114.3	-	6,114.3	6,234.2	6,748.2	-	6,748.2	6,656.0	7,188.2	-	7,188.2
9	Short-Term Debt	51.1	51.0	-	51.0	50.9	50.6	-	50.6	56.4	56.1	-	56.1	57.9	57.5	-	57.5	58.4	58.0	-	58.0
10	Existing and Planned Long-Term Debt	2,013.4	2,010.0	-	2,010.0	2,109.9	2,099.8	-	2,099.8	2,180.3	2,168.5	-	2,168.5	2,190.6	2,176.3	-	2,176.3	2,208.3	2,192.0	-	2,192.0
11	**Other Long-Term Debt Provision**	**2,258.9**	**2,677.9**	**-**	**2,677.9**	**2,233.6**	**2,635.4**	**-**	**2,635.4**	**3,393.7**	**3,889.7**	**-**	**3,889.7**	**3,985.8**	**4,514.4**	**-**	**4,514.4**	**4,389.3**	**4,938.2**	**-**	**4,938.2**
Cost of Capital ($M)																					
12	Adjustment for Lesser of UNL/ARC	3.6	3.6	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Common Equity at OEB Approved Rate**	**360.6**	**312.6**	**-**	**312.6**	**366.5**	**317.1**	**-**	**317.1**	**469.6**	**409.1**	**-**	**409.1**	**519.9**	**453.5**	**-**	**453.5**	**555.1**	**484.4**	**-**	**484.4**
14	**Common Equity at Long Term Rate**		**4.6**	**-**	**4.6**		**3.9**	**-**	**3.9**		**3.5**	**-**	**3.5**		**3.1**		**3.1**		**2.7**	**-**	**2.7**
15	Existing and Planned Long-Term Debt	72.6	72.5	-	72.5	73.5	73.2	-	73.2	78.8	78.4	-	78.4	80.0	79.5	-	79.5	80.7	80.1	-	80.1
16	Other Long-Term Debt Provision	81.4	96.5	-	96.5	77.8	91.8	-	91.8	122.6	140.6	-	140.6	145.6	164.9	-	164.9	160.4	180.5	-	180.5

Numbers may not add due to rounding

OPG Regulatory Income Taxes

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

		Nuclear Generating Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
	Applicable Tax Rates																				
1	Federal Rate	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%
3	**Total Tax Rate**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**
	Taxable Income ($M)																				
4	Earnings Before Tax	236.9	193.4	-	193.4	236.2	190.5	-	190.5	348.6	291.4	-	291.4	441.5	378.1	-	378.1	468.7	400.6	-	400.6
5	Adjustments: Additions	1,277.8	1,275.3	-	1,275.3	1,210.7	1,206.1	-	1,206.1	1,291.2	1,284.2	-	1,284.2	1,236.7	1,226.5	-	1,226.5	1,404.4	1,391.3	-	1,391.3
6	Adjustments: Deductions	1,634.9	1,621.2	-	1,621.2	1,529.2	1,510.5	-	1,510.5	1,536.7	1,516.4	-	1,516.4	1,619.2	1,594.9	-	1,594.9	1,733.2	1,708.6	-	1,708.6
7	Tax Loss Carry Over	120.3	152.5		152.5	82.3	113.9		113.9	(103.2)	(59.2)		(59.2)	(59.0)	(9.6)		(9.6)	(139.8)	(83.2)		(83.2)
8	**Total Taxable Income**	**-**	**-**	**-**	**-**	**-**	**0.0**	**-**	**0.0**	**-**	**(0.0)**	**0.0**	**-**	**-**	**-**	**-**	**-**	**0.0**	**-**	**-**	**-**
	Income Taxes ($M)																				
9	Federal Income Taxes	0.0	0.0	-	0.0	0.0	0.0	-	0.0	0.0	(0.0)	**0.0**	0.0	0.0	0.0	-	0.0	0.0	0.0	-	0.0
10	Provincial Income Taxes	0.0	0.0	-	0.0	0.0	0.0	-	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	-	0.0
11	Tax Credits (SR&ED Investment)	(16.5)	(16.5)	-	(16.5)	(16.3)	(16.3)	-	(16.3)	(16.4)	(16.4)	-	(16.4)	(16.1)	(16.1)	-	(16.1)	(15.9)	(15.9)	-	(15.9)
12	**Total Income Taxes**	**(16.5)**	**(16.5)**	**-**	**(16.5)**	**(16.3)**	**(16.3)**	**-**	**(16.3)**	**(16.4)**	**(16.4)**	0.0	**(16.4)**	**(16.1)**	**(16.1)**	**-**	**(16.1)**	**(15.9)**	**(15.9)**	**-**	**(15.9)**
	Earnings Before Tax ($M)																				
13	**Requested After Tax ROE**	**360.6**	**317.3**	**-**	**317.3**	**366.5**	**321.1**	**-**	**321.1**	**469.6**	**412.6**	**-**	**412.6**	**519.9**	**456.5**	**-**	**456.5**	**555.1**	**487.1**	**-**	**487.1**
14	Pension and OPEB Cash vs Accrual Accounts	**(152.7)**	**(152.9)**	**-**	**(152.9)**	**(152.7)**	**(152.9)**	**-**	**(152.9)**	**(152.7)**	**(152.9)**	**-**	**(152.9)**	**(108.8)**	**(108.8)**	**-**	**(108.8)**	**(108.8)**	**(108.8)**	**-**	**(108.8)**
15	Bruce Lease Net Revenues	(45.6)	(45.6)	-	(45.6)	(38.7)	(38.7)	-	(38.7)	(48.1)	(48.1)	-	(48.1)	(46.5)	(46.5)	-	(46.5)	(38.3)	(38.3)	-	(38.3)
16	Total Regulatory Income Taxes After Tax Loss Carry-Over	(16.5)	(16.5)		(16.5)	(16.3)	(16.3)		(16.3)	(16.4)	(16.4)		(16.4)	(16.1)	(16.1)		(16.1)	(15.9)	(15.9)		(15.9)
17	**Total Earnings Before Tax**	**236.9**	**193.4**	**-**	**193.4**	**236.2**	**190.5**	**-**	**190.5**	**348.6**	**291.4**	**-**	**291.4**	**441.5**	**378.1**	**-**	**378.1**	**468.7**	**400.6**	**-**	**400.6**
	Adjustments ($M)																				
	Additions																				
18	Depreciation and Amortization	553.0	550.1	-	550.1	471.5	465.9	-	465.9	578.7	570.3	-	570.3	521.6	510.8	-	510.8	568.6	555.3	-	555.3
19	Nuclear Waste Management Expenses	57.3	57.3	-	57.3	68.9	68.9	-	68.9	72.3	72.3	-	72.3	52.1	52.1	-	52.1	47.1	47.1	-	47.1
20	Receipts from Nuclear Segregated Funds	82.5	82.5	-	82.5	104.3	104.3	-	104.3	136.4	136.4	-	136.4	284.2	284.2	-	284.2	529.3	529.3	-	529.3
21	Pension and OPEB Accrual	311.7	311.7	-	311.7	294.1	294.1	-	294.1	272.8	272.8	-	272.8	228.2	228.2	-	228.2	182.6	183.5	-	183.5
22	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account	28.0	28.7	-	28.7	28.0	28.7	-	28.7	28.0	28.7	-	28.7	21.1	21.1	-	21.1	21.1	21.1	-	21.1
23	Regulatory Asset Amortization - Pension and OPEB Variance Cash vs Accrual	152.7	152.9	-	152.9	152.7	152.9	-	152.9	152.7	152.9	-	152.9	108.8	108.8	-	108.8	108.8	108.8	-	108.8
24	Regulatory Liability Amortization - Income and Other Taxes Variance Account	(1.6)	(1.6)	-	(1.6)	(1.6)	(1.6)	-	(1.6)	(1.6)	(1.6)	-	(1.6)	-	-	-	-	-	-	-	-
25	Adjustment Related to Financing Cost for Nuclear Liabilities	3.6	3.6	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion	17.4	17.4	-	17.4	16.5	16.5	-	16.5	16.3	16.3	-	16.3	16.3	16.3	-	16.3	16.1	16.1	-	16.1
27	Other	73.2	72.6	-	72.6	76.2	76.3	-	76.3	35.5	36.0	-	36.0	4.4	5.0	-	5.0	(69.3)	(70.0)	-	(70.0)
28	**Total Additions**	**1,277.8**	**1,275.3**	**-**	**1,275.3**	**1,210.7**	**1,206.1**	**-**	**1,206.1**	**1,291.2**	**1,284.2**	**-**	**1,284.2**	**1,236.7**	1,226.5	**-**	**1,226.5**	**1,404.4**	1,391.3	**-**	**1,391.3**
	Deductions																				
29	CCA	839.5	825.8	-	825.8	878.8	860.1	-	860.1	834.1	813.8	-	813.8	860.2	836.0	-	836.0	828.5	803.9	-	803.9
30	Cash Expenditures for Nuclear Waste & Decomissioning	269.6	269.6	-	269.6	262.7	262.7	-	262.7	306.1	306.1	-	306.1	463.9	463.9	-	463.9	638.4	638.4	-	638.4
31	Contributions to Nuclear Segregated Funds and Earnings	244.4	244.4	-	244.4	100.6	100.6	-	100.6	100.6	100.6	-	100.6	-	-	-	-	-	-	-	-
32	Pension Plan Contributions	148.5	148.5	-	148.5	151.5	151.5	-	151.5	152.1	152.1	-	152.1	151.7	151.7	-	151.7	123.0	123.0	-	123.0
33	OPEB Payments	98.0	98.0	-	98.0	101.4	101.4	-	101.4	103.2	103.2	-	103.2	103.8	103.8	-	103.8	104.2	104.2	-	104.2
34	SR&ED Costs Capitalized for Accounting	35.0	35.0	-	35.0	34.2	34.2	-	34.2	34.4	34.4	-	34.4	33.1	33.1	-	33.1	32.3	32.3	-	32.3
35	Other	-	-	-	-	-	-	-	-	6.1	6.1	-	6.1	6.3	6.3	-	6.3	6.9	6.9	-	6.9
36	**Total Deductions**	**1,634.9**	**1,621.2**	**-**	**1,621.2**	**1,529.2**	**1,510.5**	**-**	**1,510.5**	**1,536.7**	**1,516.4**	**-**	**1,516.4**	**1,619.2**	**1,594.9**	**-**	**1,594.9**	**1,733.2**	**1,708.6**	**-**	**1,708.6**

Numbers may not add due to rounding

OPG Revenue Requirement

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Draft Payment Amounts Order
Appendix G

		Nuclear Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
	Cost of Capital ($M)																				
1	Short-term Debt	2.9	2.9	0.0	2.9	3.0	3.0	0.0	3.0	3.6	3.6	0.0	3.6	4.0	3.9	0.0	3.9	4.3	4.3	0.0	4.3
2	Long-Term Debt	154.0	169.0	0.0	169.0	151.4	165.0	0.0	165.0	201.4	218.9	0.0	218.9	225.6	244.4	0.0	244.4	241.1	260.6	0.0	260.6
3	Common Equity at OEB Approved Rate	360.6	312.6	0.0	312.6	366.5	317.1	0.0	317.1	469.6	409.1	0.0	409.1	519.9	453.5	0.0	453.5	555.1	484.4	0.0	484.4
4	Common Equity at Long Term Rate		4.6	0.0	4.6		3.9	0.0	3.9		3.5	0.0	3.5		3.1	0.0	3.1		2.7	0.0	2.7
5	Adjustment for Lesser of UNL/ARC	3.6	3.6	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Total**	**521.1**	**492.8**	0.0	492.8	**520.9**	**489.1**	0.0	489.1	**674.6**	**635.1**	0.0	635.1	**749.5**	**704.9**	0.0	704.9	**800.5**	**751.9**	0.0	751.9
	Expenses ($M)																				
7	OM&A	2,341.2	2,276.2	0.0	2,276.2	2,382.0	2,315.0	0.0	2,315.0	2,207.1	2,137.0	0.0	2,137.0	1,869.0	1,803.3	0.0	1,803.3	1,083.3	1,038.9	0.0	1,038.9
8	Fuel	178.3	177.3	0.0	177.3	182.1	181.2	0.0	181.2	209.4	209.5	0.0	209.5	188.6	189.9	0.0	189.9	148.2	148.0	0.0	148.0
9	Depreciation/Amortization	553.0	550.1	0.0	550.1	471.5	465.9	0.0	465.9	578.7	570.3	0.0	570.3	521.6	510.8	0.0	510.8	568.6	555.3	0.0	555.3
10	Property Taxes	12.9	12.9	0.0	12.9	13.2	13.2	0.0	13.2	13.6	13.6	0.0	13.6	12.7	12.7	0.0	12.7	9.8	9.8	0.0	9.8
11	**Total**	**3,085.4**	**3,016.5**	0.0	3,016.5	**3,049.0**	**2,975.4**	0.0	2,975.4	**3,008.8**	**2,930.4**	0.0	2,930.4	**2,591.9**	**2,516.6**	0.0	2,516.6	**1,809.8**	**1,752.0**	0.0	1,752.0
	Other Revenues ($M)																				
12	Bruce Lease Net Revenues	(45.6)	(45.6)	0.0	(45.6)	(38.7)	(38.7)	0.0	(38.7)	(48.1)	(48.1)	0.0	(48.1)	(46.5)	(46.5)	0.0	(46.5)	(38.3)	(38.3)	0.0	(38.3)
13	Ancillary and Other Revenue	24.2	26.6	0.0	26.6	41.9	46.1	0.0	46.1	52.3	57.5	0.0	57.5	21.8	24.0	0.0	24.0	63.8	70.2	0.0	70.2
14	**Total**	**(21.4)**	**(19.0)**	0.0	(19.0)	**3.2**	**7.4**	0.0	7.4	**4.2**	**9.4**	0.0	9.4	**(24.7)**	**(22.5)**	0.0	(22.5)	**25.5**	**31.9**	0.0	31.9
15	**Regulatory Income Tax** ($M)	**(16.5)**	**(16.5)**	0.0	(16.5)	**(16.3)**	**(16.3)**	0.0	(16.3)	**(16.4)**	**(16.4)**	0.0	(16.4)	**(16.1)**	**(16.1)**	0.0	(16.1)	**(15.9)**	**(15.9)**	0.0	(15.9)
15	**Revenue Requirement Before Stretch Factor** ($M)	**3,611.4**	**3,511.7**	0.0	3,511.7	**3,550.4**	**3,440.8**	0.0	3,440.8	**3,662.9**	**3,539.7**	0.0	3,539.7	**3,350.1**	**3,227.9**	0.0	3,227.9	**2,569.0**	**2,456.1**	0.0	2,456.1
16	**Cumulative Nuclear Stretch Dollars** ($M)	**0.0**	**0.0**		0.0	**9.5**	**14.9**		14.9	**18.7**	**29.2**		29.2	**25.5**	**39.9**		39.9	**18.0**	**27.6**		27.6
16	**Revenue Requirement** ($M)	**3,611.4**	**3,511.7**	0.0	3,511.7	**3,540.8**	**3,425.9**	0.0	3,425.9	**3,644.2**	**3,510.5**	0.0	3,510.5	**3,324.5**	**3,188.0**	0.0	3,188.0	**2,550.9**	**2,428.5**	0.0	2,428.5

Numbers may not add due to rounding

OPG Revenue Requirement Deficiency / (Sufficiency)

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

		Nuclear Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Adjustment	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Adjustment	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Adjustment	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Adjustment	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Adjustment	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
Production & Revenue																					
1	Forecast Production (TWh)	33.2	33.6	0.0	33.6	30.8	31.2	0.0	31.2	33.3	34.0	0.0	34.0	30.2	31.1	0.0	31.1	21.5	21.9	0.0	21.9
2	Current Payment Rate ($/MWh)	89.70	89.70	0.00	89.70	89.70	89.70	0.00	89.70	89.70	89.70	0.00	89.70	89.70	89.70	0.00	89.70	89.70	89.70	0.00	89.70
3	**Revenue From Current Payment Rate ($M)**	**2,978.1**	**3,013.9**	**0.0**	**3,013.9**	**2,765.2**	**2,801.1**	**0.0**	**2,801.1**	**2,987.0**	**3,049.8**	**0.0**	**3,049.8**	**2,708.0**	**2,788.7**	**0.0**	**2,788.7**	**1,929.6**	**1,965.4**	**0.0**	**1,965.4**
Revenue Requirement																					
4	Revenue Requirement Net of Stretch Factor ($M)	3,611.4	3,511.7	0.0	3,511.7	3,540.8	3,425.9	0.0	3,425.9	3,644.2	3,510.5	0.0	3,510.5	3,324.5	3,188.0	0.0	3,188.0	2,550.9	2,428.5	0.0	2,428.5
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**633.3**	**497.7**	0.0	**497.7**	**775.6**	**624.8**	0.0	**624.8**	**657.2**	**460.7**	0.0	**460.7**	**616.6**	**399.3**	0.0	**399.3**	**621.4**	**463.1**	0.0	**463.1**

Numbers may not add due to rounding

OPG Requested Payment Amounts

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

		Hydroelectric Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreeement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
1	**Payment Amount ($/MWh)**	43.88	43.88		43.88	43.88	43.88		43.88	43.88	43.88		43.88	43.88	43.88		43.88	43.88	43.88		43.88

		Nuclear Facilities																			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
2	Revenue Requirement Net of Stretch Factor($M)	3,611.4	3,511.7	0.0	3,511.7	3,540.8	3,425.9	0.0	3,425.9	3,644.2	3,510.5	0.0	3,510.5	3,324.5	3,188.0	0.0	3,188.0	2,550.9	2,428.5	0.0	2,428.5
3	Stretch Adjustment ($M)	0.0	0.0	0.0	0.0	9.5	14.9	0.0	14.9	18.7	29.2	0.0	29.2	25.5	39.9	0.0	39.9	18.0	27.6	0.0	27.6
4	Forecast Production (TWh)	33.2	33.6	0.0	33.6	30.8	31.2	0.0	31.2	33.3	34.0	0.0	34.0	30.2	31.1	0.0	31.1	21.5	21.9	0.0	21.9
5	**Unsmoothed Payment Amount ($/MWh) (** (Line 2) / Line 4)	108.78	104.51	-	104.51	114.86	109.71	-	109.71	109.44	103.25	-	103.25	110.12	102.54	-	102.54	118.59	110.84	-	110.84
6	**Smoothed Payment Amount**	101.58	102.06	-	102.06	105.21	105.68	-	105.68	104.49	103.25	-	103.25	106.70	102.54	-	102.54	120.67	110.84	-	110.84

Numbers may not add due to rounding

OPG Recovery of Deferral and Variance Accounts and Riders

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

Previously Regulated Hydroelectric Facilities

Line No.	Description	Amortization 2022 OPG Proposed 12/31/2020	Amortization 2022 Settlement Agreement	Amortization 2022 OEB Adjustment	Amortization 2022 OEB Approved	Amortization 2023 OPG Proposed 12/31/2020	Amortization 2023 Settlement Agreement	Amortization 2023 OEB Adjustment	Amortization 2023 OEB Approved	Amortization 2024 OPG Proposed 12/31/2020	Amortization 2024 Settlement Agreement	Amortization 2024 OEB Adjustment	Amortization 2024 OEB Approved	Amortization 2025 OPG Proposed 12/31/2020	Amortization 2025 Settlement Agreement	Amortization 2025 OEB Adjustment	Amortization 2025 OEB Approved	Amortization 2026 OPG Proposed 12/31/2020	Amortization 2026 Settlement Agreement	Amortization 2026 OEB Adjustment	Amortization 2026 OEB Approved
	Variance Accounts ($M)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
1	Hydroelectric Water Conditions Variance	(36.4)	(36.4)	0.0	(36.4)	(36.4)	(36.4)	0.0	(36.4)	(36.4)	(36.4)	0.0	(36.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Ancillary Services Net Revenue Variance - Hydroelectric	(11.1)	(11.1)	0.0	(11.1)	(11.1)	(11.1)	0.0	(11.1)	(11.1)	(11.1)	0.0	(11.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Hydroelectric Incentive Mechanism Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Hydroelectric Surplus Baseload Generation Variance	69.4	56.1	0.0	56.1	69.4	56.1	0.0	56.1	69.4	56.1	0.0	56.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Income and Other Taxes Variance - Hydroelectric	(0.9)	(0.9)	0.0	(0.9)	(0.9)	(0.9)	0.0	(0.9)	(0.9)	(0.9)	0.0	(0.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Capacity Refurbishment Variance - Hydroelectric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	1.3	1.3	0.0	1.3	1.3	1.3	0.0	1.3	1.3	1.3	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Pension and OPEB Cost Variance - Hydroelectric - Future	1.1	1.1	0.0	1.1	1.1	1.1	0.0	1.1	1.1	1.1	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	8.3	8.3	0.0	8.3	8.3	8.3	0.0	8.3	8.3	8.3	0.0	8.3	8.3	8.3	0.0	8.3	8.3	8.3	0.0	8.3
11	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non - RPP - EB-2018-0243 Approved	7.0	7.0	0.0	7.0	7.0	7.0	0.0	7.0	7.0	7.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions	8.8	8.8	0.0	8.8	8.8	8.8	0.0	8.8	8.8	8.8	0.0	8.8	8.8	8.8	0.0	8.8	8.8	8.8	0.0	8.8
13	Pension & OPEB Cash Payment Variance - Hydroelectric	(12.9)	(12.9)	0.0	(12.9)	(12.9)	(12.9)	0.0	(12.9)	(12.9)	(12.9)	0.0	(12.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Pension and OPEB Cash Versus Accrual Differential Carrying Charges - Hydroelectric	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Hydroelectric Deferral and Variance Over/Under Recovery Variance	1.1	1.1	0.0	1.1	1.1	1.1	0.0	1.1	1.1	1.1	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total**	**35.7**	**22.4**	0.0	**22.4**	**35.7**	**22.4**	**0.0**	**22.4**	**35.7**	**22.4**	**0.0**	**22.4**	**17.1**	**17.1**	**0.0**	**17.1**	**17.1**	**17.1**	**0.0**	**17.1**
17	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - RPP - EB-2018-0243 Approved	2.8	2.8	0.0	2.8	2.8	2.8	0.0	2.8	2.8	2.8	0.0	2.8	2.8	2.8	0.0	2.8	2.8	2.8	0.0	2.8
18	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non RPP - EB-2018-0243 Approved	2.3	2.3	0.0	2.3	2.3	2.3	0.0	2.3	2.3	2.3	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions	2.9	2.9	0.0	2.9	2.9	2.9	0.0	2.9	2.9	2.9	0.0	2.9	2.9	2.9	0.0	2.9	2.9	2.9	0.0	2.9
20	Settlement Agreement Covid-19 Impacts	0.0	3.6	0.0	3.6	0.0	3.6	0.0	3.6	0.0	3.6	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Total Recoverable Amount**	**43.7**	**34.0**	**0.0**	**34.0**	**43.7**	**34.0**	0.0	**34.0**	**43.7**	**34.0**	0.0	**34.0**	**22.8**	**22.8**	0.0	**22.8**	**22.8**	**22.8**	0.0	**22.8**
22	**EB-2016-0152 PAO forecast** (TWh)	**33.0**	**33.0**		**33.0**	**33.0**	**33.0**		**33.0**	**33.0**	**33.0**		**33.0**	**33.0**	**33.0**		**33.0**	**33.0**	**33.0**		**33.0**
23	**Rider** ($/MWh) (Line 20 / Line 21)	**1.33**	**1.03**	0.0	**1.03**	**1.33**	**1.03**	0.0	**1.03**	**1.33**	**1.03**	0.0	**1.03**	**0.69**	**0.69**	0.0	**0.69**	**0.69**	**0.69**	0.0	**0.69**

Nuclear Facilities

Line No.	Description	Amortization 2022 OPG Proposed 12/31/2020	Amortization 2022 Settlement Agreement	Amortization 2022 OEB Adjustment	Amortization 2022 OEB Approved	Amortization 2023 OPG Proposed 12/31/2020	Amortization 2023 Settlement Agreement	Amortization 2023 OEB Adjustment	Amortization 2023 OEB Approved	Amortization 2024 OPG Proposed 12/31/2020	Amortization 2024 Settlement Agreement	Amortization 2024 OEB Adjustment	Amortization 2024 OEB Approved	Amortization 2025 OPG Proposed 12/31/2020	Amortization 2025 Settlement Agreement	Amortization 2025 OEB Adjustment	Amortization 2025 OEB Approved	Amortization 2026 OPG Proposed 12/31/2020	Amortization 2026 Settlement Agreement	Amortization 2026 OEB Adjustment	Amortization 2026 OEB Approved
	Variance Accounts ($M)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
24	Nuclear Liability Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Impact Resulting from Changes in Station End-of-Life Dates (Dec 31, 2015) Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Nuclear Development Variance	1.2	1.2	0.0	1.2	1.2	1.2	0.0	1.2	1.2	1.2	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Ancillary Services Net Revenue Variance - Nuclear	(1.2)	(1.2)	0.0	(1.2)	(1.2)	(1.2)	0.0	(1.2)	(1.2)	(1.2)	0.0	(1.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Capacity Refurbishment Variance - Nuclear - DRP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Capacity Refurbishment Variance - Nuclear - Non-DRP	(34.3)	(32.0)	0.0	(32.0)	(34.3)	(32.0)	0.0	(32.0)	(34.3)	(32.0)	0.0	(32.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA-DRP	(6.4)	(6.4)	0.0	(6.4)	(6.4)	(6.4)	0.0	(6.4)	(6.4)	(6.4)	0.0	(6.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Capacity Refurbishment Variance - Nuclear - D2O	19.4	19.3	0.0	19.3	19.4	19.3	0.0	19.3	19.4	19.3	0.0	19.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(0.7)	0.0	0.0	0.0	(0.7)	0.0	0.0	0.0	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243 Approved	21.1	21.1	0.0	21.1	21.1	21.1	0.0	21.1	21.1	21.1	0.0	21.1	21.1	21.1	0.0	21.1	21.1	21.1	0.0	21.1
34	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post-2017 Additions	7.7	7.7	0.0	7.7	7.7	7.7	0.0	7.7	7.7	7.7	0.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Income and Other Taxes Variance - Nuclear	(4.8)	(4.8)	0.0	(4.8)	(4.8)	(4.8)	0.0	(4.8)	(4.8)	(4.8)	0.0	(4.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Pension and OPEB Cost Variance - Nuclear - Future	21.5	21.5	0.0	21.5	21.5	21.5	0.0	21.5	21.5	21.5	0.0	21.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved	53.2	53.2	0.0	53.2	53.2	53.2	0.0	53.2	53.2	53.2	0.0	53.2	53.2	53.2	0.0	53.2	53.2	53.2	0.0	53.2
39	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non - RPP - EB-2018-0243 Approved	44.1	44.1	0.0	44.1	44.1	44.1	0.0	44.1	44.1	44.1	0.0	44.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions	55.6	55.6	0.0	55.6	55.6	55.6	0.0	55.6	55.6	55.6	0.0	55.6	55.6	55.6	0.0	55.6	55.6	55.6	0.0	55.6
41	Pension & OPEB Cash Payment Variance - Nuclear	(58.1)	(58.1)	0.0	(58.1)	(58.1)	(58.1)	0.0	(58.1)	(58.1)	(58.1)	0.0	(58.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Pension and OPEB Cash Versus Accrual Differential Carrying Charges - Nuclear	(0.2)	(0.2)	0.0	(0.2)	(0.2)	(0.2)	0.0	(0.2)	(0.2)	(0.2)	0.0	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Nuclear Deferral and Variance Over/Under Recovery Variance	(7.7)	(8.4)	0.0	(8.4)	(7.7)	(8.4)	0.0	(8.4)	(7.7)	(8.4)	0.0	(8.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Fitness for Duty Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	SR&ED ITC Variance	(4.0)	(4.0)	0.0	(4.0)	(4.0)	(4.0)	0.0	(4.0)	(4.0)	(4.0)	0.0	(4.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Rate Smoothing Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	(81.9)	(81.9)	0.0	(81.9)	(81.9)	(81.9)	0.0	(81.9)	(81.9)	(81.9)	0.0	(81.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	**Total**	**24.4**	**26.6**	**0.0**	26.6	**24.4**	**26.6**	**0.0**	26.6	**24.4**	**26.6**	**0.0**	**26.6**	**129.9**	**129.9**	**0.0**	**129.9**	**129.9**	**129.9**	**0.0**	**129.9**
49	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - RPP - EB-2018-0243 Approved	17.7	17.7	0.0	17.7	17.7	17.7	0.0	17.7	17.7	17.7	0.0	17.7	17.7	17.7	0.0	17.7	17.7	17.7	0.0	17.7
50	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non RPP - EB-2018-0243 Approved	14.7	14.7	0.0	14.7	14.7	14.7	0.0	14.7	14.7	14.7	0.0	14.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions	18.5	18.5	0.0	18.5	18.5	18.5	0.0	18.5	18.5	18.5	0.0	18.5	18.5	18.5	0.0	18.5	18.5	18.5	0.0	18.5
52	Settlement Agreement Covid-19 Impacts	0.0	(19.2)	0.0	(19.2)	0.0	(19.2)	0.0	(19.2)	0.0	(19.2)	0.0	(19.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	**Total Recoverable Amount**	**75.4**	**58.4**	0.0	**58.4**	**75.4**	**58.4**	0.0	**58.4**	**75.4**	**58.4**	0.0	**58.4**	**166.2**	**166.2**	0.0	166.2	**166.2**	**166.2**	0.0	**166.2**
54	**Forecast Production** (TWh)	**33.2**	**33.6**	0.0	**33.6**	**30.8**	**31.2**	0.0	**31.2**	**33.3**	**34.0**	0.0	**34.0**	**30.2**	**31.1**	0.0	**31.1**	**21.5**	**21.9**	0.0	**21.9**
55	**Rider** ($/MWh) (Line 51 / Line 52)	**2.27**	**1.74**	0.0	**1.74**	**2.44**	**1.87**	0.0	**1.87**	**2.26**	**1.72**	0.0	**1.72**	**5.50**	**5.34**	0.0	**5.34**	**7.72**	**7.58**	0.0	**7.58**

Numbers may not add due to rounding

OPG Customer Bill Impacts

Updated: 2021-07-16
EB-2020-0290
Draft Payment Amounts Order
Appendix G

		Residential Consumers																			
		EB-2016-0152 >> EB-2020-0290				EB-2020-0290				EB-2020-0290				EB-2020-0290				EB-2020-0290			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
	Production and Demand																				
1	Typical Usage, including Line Losses[1] (kWh/Month)	737	737	n/a	737	737	737	n/a	737	737	737	n/a	737	737	737	n/a	737	737	737	n/a	737
2	Forecast Production (TWh)	66.2	66.6	-	66.6	63.8	64.2	-	64.2	66.3	67.0	-	67.0	63.2	64.1	-	64.1	54.5	54.9	-	54.9
3	IESO Forecast Provincial Demand[2] (TWh)	134.3	135.2	n/a	135.2	134.3	135.2	n/a	135.2	134.3	135.2	n/a	135.2	134.3	135.2	n/a	135.2	134.3	135.2	n/a	135.2
4	OPG Proportion of Consumer Usage (line 2 / line 3)	49.3%	49.2%	0.0%	49.2%	47.5%	47.5%	0.0%	47.5%	49.4%	49.5%	0.0%	49.5%	47.0%	47.4%	0.0%	47.4%	40.6%	40.6%	0.0%	40.6%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	363	363	-	363	350	350	-	350	364	365	-	365	347	349	-	349	299	299	-	299
6	**Typical Bill[1] ($/Month)**	**115.11**	**115.11**	n/a	**115.11**	**115.11**	**115.11**	n/a	**115.11**	**115.11**	**115.11**	n/a	**115.11**	**115.11**	**115.11**	n/a	**115.11**	**115.11**	**115.11**	n/a	**115.11**
	Production-Weighted Average Rates																				
7	Prior Year weighted average rate with proposed payment amounts and riders ($/MWh)	71.76	71.76	-	71.76	74.63	74.63	-	74.63	75.38	75.38	-	75.38	76.13	75.40	-	75.40	76.89	75.29	-	75.29
8	Current Year weighted average rate with proposed payment amounts and riders ($/MWh)	74.63	74.63	-	74.63	75.38	75.38	-	75.38	76.13	75.40	-	75.40	76.89	75.29	-	75.29	77.66	74.05	-	74.05
	Impact																				
9	**Typical Bill Impact** ($/Month)	**1.04**	**1.04**	**-**	**1.04**	**0.26**	**0.26**	**-**	**0.26**	**0.27**	**0.01**	**-**	**0.01**	**0.26**	**(0.04)**	**-**	**(0.04)**	**0.23**	**(0.37)**	**-**	**(0.37)**
10	**Percentage Change of Typical Bill** (line 9 / line 6)	**0.9%**	**0.9%**	**0.0%**	**0.9%**	**0.2%**	**0.2%**	**0.0%**	**0.2%**	**0.2%**	**0.0%**	**0.0%**	**0.0%**	**0.2%**	**0.0%**	**0.0%**	**0.0%**	**0.2%**	**-0.3%**	**0.0%**	**-0.3%**

		Current Rates			
Line No.	Description	OPG Proposed	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Payment Amounts ($MWh)				
11	Regulated Hydroelectric	43.88	43.88	n/a	43.88
12	Nuclear	89.70	89.70	n/a	89.70
	Riders ($MWh)				
13	Regulated Hydroelectric	2.05	2.05	n/a	2.05
14	Nuclear	6.13	6.13	n/a	6.13
	Total Annual Rates ($MWh)				
15	Regulated Hydroelectric	45.93	45.93	n/a	45.93
16	Nuclear	95.83	95.83	n/a	95.83
	Forecast Production EB-2020-XXXX (TWh)				
17	Regulated Hydroelectric	32.98	32.98	n/a	32.98
18	Nuclear	35.4	35.4	n/a	35.4
19	**Total**	**68.4**	**68.4**	**-**	**68.4**
	Production-Weighted Average Rates ($MWh)				
20	Regulated Hydroelectric	22.15	22.15	n/a	22.15
21	Nuclear	49.61	49.61	-	49.61
22	**Total** (line 20 + line 21)	**71.76**	**71.76**	**-**	**71.76**
23	**Total Production-Weighted Average Rate** ($MWh)	**71.76**	**71.76**	**-**	**71.76**

		EB-2020-0290				EB-2020-0290				EB-2020-0290				EB-2020-0290				EB-2020-0290			
		Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates			
		2022				2023				2024				2025				2026			
Line No.	Description	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved	OPG Proposed 12/31/2020	Settlement Agreement	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)
	Payment Amounts ($MWh)																				
24	Regulated Hydroelectric	43.88	43.88	-	43.88	43.88	43.88	-	43.88	43.88	43.88	-	43.88	43.88	43.88	-	43.88	43.88	43.88	-	43.88
25	Nuclear	101.58	102.06	-	102.06	105.21	105.68	-	105.68	104.49	103.25	-	103.25	106.70	102.54	-	102.54	120.67	110.84	-	110.84
	Riders ($MWh)																				
26	Regulated Hydroelectric	1.33	1.03	-	1.03	1.33	1.03	-	1.03	1.33	1.03	-	1.03	0.69	0.69	-	0.69	0.69	0.69	-	0.69
27	Nuclear	2.27	1.74	-	1.74	2.44	1.87	-	1.87	2.26	1.72	-	1.72	5.50	5.34	-	5.34	7.72	7.58	-	7.58
	Total Annual Rates ($MWh)																				
28	Regulated Hydroelectric	45.21	44.91	-	44.91	45.21	44.91	-	44.91	45.21	44.91	-	44.91	44.57	44.57	-	44.57	44.57	44.57	-	44.57
29	Nuclear	103.85	103.80	-	103.80	107.65	107.55	-	107.55	106.75	104.97	-	104.97	112.20	107.88	-	107.88	128.39	118.42	-	118.42
	Forecast Production EB-2020-0290 (TWh)																				
30	Regulated Hydroelectric	33.0	33.0	n/a	32.98	33.0	33.0	n/a	32.98	33.0	33.0	n/a	32.98	33.0	33.0	n/a	32.98	33.0	33.0	n/a	32.98
31	Nuclear	33.2	33.6	-	33.6	30.8	31.2	-	31.2	33.3	34.0	-	34.0	30.2	31.1	-	31.1	21.5	21.9	-	21.9
32	**Total**	**66.2**	**66.6**	**-**	**66.6**	**63.8**	**64.2**	**-**	**64.2**	**66.3**	**67.0**	**-**	**67.0**	**63.2**	**64.1**	**-**	**64.1**	**54.5**	**54.9**	**-**	**54.9**
	Production-Weighted Average Rates ($MWh)																				
33	Regulated Hydroelectric	22.53	22.25	n/a	22.25	23.37	23.07	n/a	23.07	22.50	22.11	n/a	22.11	23.27	22.94	n/a	22.94	26.98	26.78	n/a	26.78
34	Nuclear	52.10	52.38	-	52.38	52.01	52.31	-	52.31	53.63	53.28	-	53.28	53.62	52.35	-	52.35	50.68	47.27	-	47.27
35	**Total** (line 20 + line 21)	**74.63**	**74.63**	**-**	**74.63**	**75.38**	**75.38**	**-**	**75.38**	**76.13**	**75.40**	**-**	**75.40**	**76.89**	**75.29**	**-**	**75.29**	**77.66**	**74.05**	**-**	**74.05**
36	**Total Production-Weighted Average Rate** ($MWh)	**74.63**	**74.63**	**-**	**74.63**	**75.38**	**75.38**	**-**	**75.38**	**76.13**	**75.40**	**-**	**75.40**	**76.89**	**75.29**	**-**	**75.29**	**77.66**	**74.05**	**-**	**74.05**

Numbers may not add due to rounding

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
Typical Consumption includes line losses (Assumed loss factor of 1.0525)

2 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.