Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2020-0290

ONTARIO POWER GENERATION INC.

Application for Payment Amounts for the Period from January 1, 2022 to December 31, 2026

BEFORE: **Allison Duff**
Presiding Commissioner

Michael Janigan
Commissioner

Pankaj Sardana
Commissioner

November 15, 2021

Ontario Energy Board | Commission de l'énergie de l'Ontario

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1 OVERVIEW

This is a Decision and Order of the Ontario Energy Board (OEB) regarding an application filed by Ontario Power Generation Inc. (OPG) on December 31, 2020. The application seeks approval for changes in payment amounts for the output of OPG's nuclear generating facilities in each of the five years beginning January 1, 2022 and ending on December 31, 2026. OPG also requested approval 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 on December 31, 2021 for the period from January 1, 2022 to December 31, 2026.

OPG filed a settlement proposal on July 16, 2021 covering nearly all of the issues in the proceeding, with only a limited number of partially settled and unsettled issues. The OEB granted oral approval (with reasons to follow) of the settlement proposal at the conclusion of the oral hearing on the unsettled issues on August 6, 2021. The reasons for the OEB's approval of the settlement proposal are included as part of this Decision and Order.

OPG's payment amounts relate to generation from its nuclear and hydroelectric facilities. The payment amounts make up part of the electricity line item on customers' bills. The approved settlement proposal (and OPG's rate smoothing proposal) results in the bill impacts set out below for a typical residential customer. Because those bill impacts were calculated at the time of the settlement they do not reflect the OEB's findings in this Decision and Order, the update to the return on equity rate for the 2022-2026 period, and the OEB's pending decision on rate smoothing (which will be addressed as part of the draft payment amounts order process).

Table 1: Bill Impacts for a Typical Residential Customer

	2022	2023	2024	2025	2026	Average
Monthly Bill Impacts ($)	$1.04	$0.26	$0.01	$(0.04)	$(0.37)	$0.18
Monthly Bill Impacts (%)	0.90%	0.23%	0.01%	-0.03%	-0.32%	0.16%

The issues that were not settled as part of the settlement proposal and the OEB's findings on these issues are summarized below.

1. Small Modular Reactor-related Issues[1]
    a. Whether OPG's Small Modular Reactor-related costs are consistent with the purpose of the Nuclear Development Variance Account and thereby appropriate to be booked in this account
    b. How OPG could further improve its customer engagement process in respect of a potential Small Modular Reactor generating station at the Darlington site
    c. Whether the reporting and record keeping requirements proposed by OPG are appropriate in respect of a potential Small Modular Reactor generating station at the Darlington site.

For the reasons that follow, the OEB finds that OPG's Small Modular Reactor-related costs are appropriately recorded in the Nuclear Development Variance Account. In addition, the OEB will not direct OPG to conduct additional customer engagement on Small Modular Reactor-related costs and activities. Finally, the OEB finds that no additional Small Modular Reactor-specific reporting requirements are necessary.

2. Heavy Water Storage and Drum Handling Facility-related Issues[2]
    a. Whether the proposed test period in-service additions for the Heavy Water Storage and Drum Handling Facility are reasonable
    b. Whether the deferral and variance balances associated with the Heavy Water Storage and Drum Handling Facility are reasonable.

For the reasons that follow, the OEB finds it appropriate to apply a permanent rate base disallowance to the Heavy Water Storage and Drum Handling Facility comprised of $94 million and also the amount of carrying costs incurred during the period from May 2017 to March 2020. The OEB also finds that the appropriate in-service date for the proposed 2016 and 2019 Heavy Water Storage and Drum Handling Facility-related in-service additions is March 2020. OPG is directed to recalculate the associated deferral and variance account balances and rate base in accordance with this Decision and Order.

The approved settlement proposal includes an agreement to defer the consideration of rate smoothing. The OEB has provided direction in section 6 of this Decision and Order with respect to the rate smoothing evidence that it expects OPG to file. The OEB's final determination on rate smoothing will be included in a subsequent decision.

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[1] The Small Modular Reactor-related issues are contained within Issues 1.2, 13.1, and 14.1 as set out in the OEB's approved Issues List.
[2] The Heavy Water Storage and Drum Handling Facility-related issues are contained within Issues 7.6 and 13.2 as set out in the OEB's approved Issues List.

2 CONTEXT AND PROCESS

OPG filed an application dated December 31, 2020, with the OEB under section 78.1 of the *Ontario Energy Board Act, 1998* (OEB Act).

The OEB issued a Notice of Hearing on January 14, 2021. The Notice of Hearing was published in various newspapers and was posted on the OEB's website and OPG's website.

The following parties requested and were granted intervenor status in the proceeding.

- Association of Major Power Consumers in Ontario (AMPCO)
- Building Owners and Managers Association (BOMA)[3]
- Canadian Manufacturers & Exporters (CME)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence Canada Inc. (Environmental Defence)
- Independent Electricity System Operator (IESO)
- 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)
- SNC Lavalin Nuclear Inc. and Aecon Construction Group Inc. (CanAtom)[4]
- Society of United Professionals (Society)
- Vulnerable Energy Consumers Coalition (VECC)

AMPCO, BOMA, CME, CCC, Energy Probe, Environmental Defence, LPMA, OAPPA, OSEA, QMA, SEC, and VECC applied for and were granted cost eligibility.

The OEB approved an Issues List in its May 20, 2021 Decision on Issues List and amended it in the May 27, 2021 Decision on Motions. The final approved Issues List is attached as Schedule A to the Decision on Motions.

[3] By letter dated May 26, 2021, BOMA withdrew as an intervenor in the proceeding.
[4] CanAtom sought status as an intervenor that was limited to participation in any issues arising from the eligibility for recovery of costs regarding contracts related to the refurbishment or replacement of facilities at OPG's Darlington site.

A settlement conference was held between June 7, 2021 and June 14, 2021. OPG and the following intervenors participated in the settlement conference: AMPCO, CME, CCC, Energy Probe, Environmental Defence, LPMA, OAPPA, OSEA, PWU, QMA, SEC, Society, and VECC (the Parties).

OPG filed a settlement proposal on July 16, 2021. All of the Parties supported the settlement proposal except Environmental Defence, PWU and Society, who each took no position on the settlement proposal. OEB staff filed a submission supporting the settlement proposal on July 22, 2021.

The settlement proposal covered nearly all of the issues set out in the Issues List, with only a limited number of partially settled and unsettled issues.

The OEB approved the settlement proposal at the conclusion of the oral hearing held between August 4 and August 6, 2021. The reasons for its approval of the settlement proposal are included as part of this Decision and Order (Decision).

The oral hearing addressed the unsettled issues, which relate to Small Modular Reactors (SMR) and the Heavy Water Storage and Drum Handling Facility project (D2O Project). The OEB received submissions on these unsettled issues from OEB staff, AMPCO / CCC,[5] CME, Energy Probe, Environmental Defence, LPMA, OAPPA, PWU, QMA, SEC, Society, and VECC. The OEB also received an argument-in-chief and reply submission from OPG with respect to these issues.

The approved settlement proposal includes an agreement to defer the consideration of rate smoothing to the payment amounts order stage of the proceeding. The Decision sets out the rate smoothing evidence that OPG shall file as part of the draft payment amounts order and also establishes the process for addressing rate smoothing (and the overall draft payment amounts order).

[5] AMPCO and CCC filed a joint submission on the unsettled issues.

3 SETTLEMENT PROPOSAL

OPG filed a settlement proposal on July 16, 2021 covering nearly all of the issues set out in the Issues List, with only a limited number of partially settled and unsettled issues.

The settlement proposal results in a reduction to the proposed 2022-2026 revenue requirements, an increase to the proposed 2022-2026 production forecasts and a reduction to the amortization of deferral and variance account (DVA) balances and other amounts.[6] The following tables highlight the impact of the settlement proposal relative to the amounts OPG proposed in the application (updated for certain corrections).[7]

Table 2: Impact of Settlement Proposal on Rate Base[8]

($ millions)	2022	2023	2024	2025	2026
Proposed Rate Base	$8,719.00	$8,788.80	$11,262.40	$12,471.60	$13,316.60
Settled Rate Base	$8,689.80	$8,701.40	$11,117.00	$12,269.50	$13,069.40
Variance	$(29.20)	$(87.40)	$(145.40)	$(202.10)	$(247.20)

[6] The other amounts include tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the recovery (hydroelectric business segment) and refund (nuclear business segment) of the impact of the COVID-19 pandemic.
[7] The proposed amounts discussed in the following tables are updated for certain corrections as described in Settlement Proposal / Draft Payment Amount Order / Appendix A / Table 6. In addition, some of the settled amounts in these tables will change based on the OEB's determinations with respect to the unsettled issues and the agreement to update the return on equity (ROE) rate for the 2022-2026 period based on the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Parameters letter as of the effective date of the final payment amounts order in this proceeding.
[8] Settlement Proposal / pp. 9-13.

Table 3: Impact of Settlement Proposal on Revenue Requirement[9]

($ millions)	2022	2023	2024	2025	2026	Total
Proposed Revenue Requirement (RR)	$3,609.30	$3,538.80	$3,642.00	$3,325.80	$2,552.40	$16,668.30
Cost of Capital	$(28.20)	$(31.80)	$(39.60)	$(44.80)	$(48.90)	$(193.30)
OM&A	$(64.50)	$(66.50)	$(69.30)	$(68.40)	$(47.10)	$(315.80)
Other Expenses	$(2.40)	$(5.00)	$(6.80)	$(8.10)	$(11.90)	$(34.20)
Other Revenues	$(2.40)	$(4.20)	$(5.20)	$(2.20)	$(6.40)	$(20.40)
Stretch Factor	$ -	$(5.40)	$(10.60)	$(14.40)	$(9.50)	$(39.90)
Settled RR	$3,511.80	$3,425.90	$3,510.50	$3,187.90	$2,428.60	$16,064.70
Variance ($)	$(97.50)	$(112.90)	$(131.50)	$(137.90)	$(123.80)	$(603.60)
Variance (%)	-2.70%	-3.19%	-3.61%	-4.15%	-4.85%	-3.62%

Table 4: Impact of Settlement Proposal on Production Forecast[10]

(TWh)	2022	2023	2024	2025	2026	Total
Proposed Nuclear Production Forecast	33.2	30.8	33.3	30.2	21.5	149
Settled Nuclear Production Forecast	33.6	31.2	34.0	31.1	21.9	151.8
Variance	0.4	0.4	0.7	0.9	0.4	2.8

Table 5: Impact of Settlement Proposal on Nuclear-related DVA and Other Amount Amortization[11]

($ millions)	2022	2023	2024	2025	2026	Total
Proposed Nuclear DVA Disposition	$77.60	$77.60	$77.60	$166.20	$166.20	$565.20
Settled Nuclear DVA Disposition	$58.40	$58.40	$58.40	$166.20	$166.20	$507.60
Variance	$(19.20)	$(19.20)	$(19.20)	$ -	$ -	$(57.60)

[9] *Ibid.*
[10] *Ibid.*
[11] *Ibid.* The other amounts include tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the refund of the COVID-19 pandemic impact credit (nuclear).

Table 6: Impact of Settlement Proposal on Hydroelectric-related DVA and Other Amount Amortization[12]

($ millions)	2022	2023	2024	2025	2026	Total
Proposed Hydroelectric DVA Disposition	$43.70	$43.70	$43.70	$22.80	$22.80	$176.70
Settled Hydroelectric DVA Disposition	$34.00	$34.00	$34.00	$22.80	$22.80	$147.60
Variance	$(9.70)	$(9.70)	$(9.70)	$ -	$ -	$(29.10)

Table 7: Impact of Settlement Proposal and Updated Rate Smoothing Proposal on Deferred Revenue Amounts[13]

($ millions)	2022	2023	2024	2025	2026	Total
Proposed Deferred Revenue Amounts	$241.20	$299.90	$167.00	$103.40	$(44.80)	$766.70
Updated Deferred Revenue Amounts	$82.40	$125.70	$ -	$ -	$ -	$208.10
Variance	$(158.80)	$(174.20)	$(167.00)	$(103.40)	$44.80	$(558.60)

OEB staff filed a submission on July 22, 2021 that supported the settlement proposal. OEB staff submitted that the settlement proposal is consistent with the OEB's statutory objectives under section 1 of the OEB Act, in particular, the protection of consumers with respect to prices and the adequacy, reliability and quality of electricity service, and the promotion of cost effectiveness in the generation of electricity, while facilitating the maintenance of a financially viable electricity sector.[14]

Findings

The OEB approved the settlement proposal at the conclusion of the oral hearing on August 6, 2021, with written reasons to follow. The approved settlement proposal is attached as Schedule A to the Decision. The OEB approved the settlement proposal

[12] *Ibid.* The other amounts include tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the recovery of the COVID-19 pandemic impact debit (hydroelectric).
[13] *Ibid.* / p. 14. The updated rate smoothing proposal was filed on July 16, 2021 under separate cover.
[14] OEB Staff Submission on Settlement Proposal / p. 9.

orally to provide regulatory certainty to OPG, intervenors and OEB staff in preparing submissions for the remaining unsettled issues.

The OEB's reasons for approving the settlement proposal are as follows.

The OEB finds that the settlement proposal represents a reasonable outcome for ratepayers and will result in just and reasonable payment amounts. Relative to OPG's application, the settlement proposal includes:

- $603.6 million (3.62%) reduction in total revenue requirement over the 2022-2026 period[15]
- Significant reductions to rate base in each year of the 2022-2026 period[16]
- 2.8 TWh increase to the total nuclear production forecast over the 2022-2026 period[17]
- 25.9% reduction in revenue deficiency[18]
- $57.6 million reduction in Nuclear DVA balances for disposition[19]
- $29.1 million reduction in Hydroelectric DVA balances for disposition.[20]

Some of these numbers will change based on the OEB's findings on the unsettled issues.[21]

The OEB has considered the settlement proposal in the context of its statutory objectives under section 1 of the OEB Act, specifically to protect customers with respect to:

- Electricity prices
- Adequacy, reliability and quality of electricity service
- Promotion of cost effectiveness in electricity generation while facilitating the maintenance of a financially viable electricity sector.

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[15] *Ibid.* / p. 15.
[16] *Ibid.* / p. 20.
[17] *Ibid.* / p. 15.
[18] OEB Staff Submission on Settlement Proposal / p. 4.
[19] Settlement Proposal / pp. 9-13.
[20] *Ibid.*
[21] The numbers may also be impacted by the agreement to update the ROE rate for the 2022-2026 period based on the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Parameters letter as of the effective date of the final payment amounts order in this proceeding.

The OEB finds that the settlement proposal is comprehensive as there was full settlement on 30 of the 36 issues in this proceeding. Further, there was partial settlement on four issues. Given the comprehensive nature of the settled and partially settled issues, the OEB finds that the expected outcomes of the settlement proposal will serve to protect customers and provide OPG with the funding it requires to operate its prescribed generation facilities safely and effectively during the 2022-2026 period.

The settlement proposal explicitly requests that the OEB consider and accept the proposal as a package.[22] The OEB is familiar with this type of request. It is common that settlement proposals filed with the OEB include such a condition. The OEB finds that this is a reasonable request given the joint effort required by parties during a settlement conference to discuss, propose, refine, and agree on proposals for the OEB's consideration.

The OEB notes that the settlement conference was attended by parties with diverse interests. Representatives for 13 intervenors participated in the settlement conference, including eight ratepayer groups.[23] The OEB considered OEB staff's submission regarding the settlement proposal. OEB staff supported the settlement proposal and recommended the OEB approve it. OEB staff "strongly" believed the settlement proposal was in the public interest and was a "good outcome" for ratepayers.[24]

The OEB appreciates the effort involved by the parties to participate in a settlement conference given the number of participants and the complexity of the issues. While the OEB panel of Commissioners was not privy to the discussion, the filing of the settlement proposal is evidence that parties successfully adapted to a virtual settlement conference "room" and overcame logistical barriers.

The OEB found the schedule, mutually proposed by parties for procedural steps after the settlement proposal, to be extremely helpful. The proposed schedule demonstrated a concerted effort to streamline the proceeding and gain efficiencies:

- Eliminated procedural steps provisionally established in Procedural Order No. 1 (as shown in the illustrative schedules)
- Reduced the oral hearing from potentially 22 days to three days
- Submissions focused on only the four partially settled issues and one unsettled issue.

[22] Settlement Proposal / p. 6.
[23] *Ibid.* / p. 4.
[24] OEB Staff Submission on Settlement Proposal / pp. 9-10.

This contracted hearing schedule enabled the Decision to be issued in 2021, before the start of the 2022-2026 payment amounts period and within the OEB's 355-day metric for this proceeding.

This may be the first substantial settlement proposal filed in an OPG proceeding since OPG became subject to OEB regulation. In addition, the OEB acknowledges the "new" aspects of the settlement proposal that were not included in OPG's application. This indicates a progressive discussion and resolution among participants during the settlement conference, specifically:

- Earning sharing mechanism – an asymmetrical mechanism applicable to both OPG's hydroelectric and nuclear generation businesses. While it is "new" to OPG, it is a common aspect for other OEB-regulated entities selecting the Custom IR option.[25]

- COVID-19 pandemic impact – ratepayers will receive a credit of $46.6 million disposed over a three-year period (2022-2024) related to OPG's response to the COVID-19 pandemic in 2020 and 2021,[26] notwithstanding that the 2020 and 2021 payment amounts were approved on final basis. It is a novel proposal given the pandemic's unexpected impact on OPG's nuclear production.

- Lower return on a portion of rate base – for $358 million of actual 2017-2021 in-service capital additions that are in excess of OPG's forecasted and the OEB-approved amounts set out in OPG's 2017-2021 Payment Amounts proceeding,[27] the long-term debt rate replaces the higher ROE rate on the equity portion in the applicable weighted average cost of capital.[28] OEB staff remarked that this is a "reasonable and creative" approach.[29] The OEB agrees.

- Resume the Pension and Other Post-Employment Benefit (OPEB) Cost Variance Account – this variance account enables the true-up of pension and OPEB costs

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[25] Settlement Proposal / p. 18.
[26] *Ibid.* / pp. 19-20.
[27] More specifically, as shown at Settlement Proposal / pp. 23-24, the $358 million amount is calculated as: (a) 100% of the difference between OPG's actual 2017-2021 in-service capital additions and the forecasted amounts in OPG's 2017-2021 Payment Amounts proceeding; and (b) 50% of the difference between the 2017-2021 forecasted and OEB-approved in-service capital additions in OPG's 2017-2021 Payment Amounts proceeding. These amounts exclude the Darlington Refurbishment Program (DRP)-related capital.
[28] Settlement Proposal / pp. 23-24.
[29] OEB Staff Submission on Settlement Proposal / pp. 8-9.

recovered from ratepayers to the actual costs incurred by OPG.[30] The resumption effectively extends the status quo in place since 2011, ensuring that neither OPG nor ratepayers are harmed by forecasting variances and cost volatility.

The OEB is satisfied with the results of the approved settlement proposal.

[30] Settlement Proposal / pp. 28-29.

4 SMALL MODULAR REACTOR-RELATED ISSUES

The following SMR-related issues were not settled:

a. Whether OPG's SMR-related costs are consistent with the purpose of the Nuclear Development Variance Account (NDVA) and thereby appropriate to be booked in this account.

b. How OPG could further improve its customer engagement process in respect of a potential SMR generating station at the Darlington site.

c. Whether the reporting and record keeping requirements proposed by OPG are appropriate in respect of a potential SMR generating station at the Darlington site.

4.1 Appropriateness of Recording Small Modular Reactor-related Costs in the NDVA

In its Decision on Issues List, dated May 20, 2021, the OEB defined the issue in this proceeding with respect to SMRs as follows, "[t]he OEB will consider the narrow issue of whether OPG's SMR-related costs are consistent with the purpose of the NDVA and thereby appropriate to be booked in the account."[31]

In the pre-filed evidence, OPG forecast OM&A expenses of $66 million in 2020 and $206 million in 2021 (total of $272 million) associated with the preliminary planning and preparation for an SMR generating station at the Darlington site. There was no forecast of planning and preparation expenditures for the development of an SMR included in OPG's 2017-2021 Payment Amounts proceeding.[32] Therefore, OPG proposed to record the preliminary planning and preparation amounts expected to be incurred in 2020 and 2021 related to the SMR project in the NDVA. OPG is not seeking disposition of the SMR-related amounts recorded in the NDVA in the current proceeding. OPG also noted that there are no SMR-related costs included in its proposed 2022-2026 revenue requirements.[33]

[31] Decision on Issues List / p. 9.
[32] EB-2016-0152.
[33] Exhibit F2 / Tab 8 / Schedule 1 / pp. 1-2; and Oral Hearing Transcripts / Vol. 1 / p. 29.

Through the course of the proceeding, OPG updated its forecast OM&A expenses over the 2020-2021 period associated with the preliminary planning and preparation for an SMR generating station at the Darlington site to $166 million.[34]

OPG submitted that its SMR-related costs are consistent with the purpose of the NDVA and appropriate to be recorded in the account.[35]

OPG submitted that the OEB's obligation under section 6(2)4.1 of O. Reg. 53/05 (Payments under Section 78.1 of the Act) is to ensure that OPG recovers the prudent capital and non-capital costs and firm financial commitments to plan and prepare for the development of proposed new nuclear generation, and the NDVA (which is established by section 5.4 of O. Reg. 53/05) is a mechanism by which the OEB fulfills that obligation with respect to the non-capital amounts.[36] Specifically, section 5.4 of O. Reg. 53/05 requires OPG to establish the NDVA to record those non-capital costs incurred and firm financial commitments made in the course of planning and preparation for development of proposed new nuclear generation, to the extent those costs are not reflected in the approved payment amounts (though see the discussion of the recent amendments to this section below). This enables the OEB to track and assess the prudence of the historic non-capital amounts in respect of planning and preparation activities for new nuclear generation facilities on an actual basis, and in turn set appropriate payment riders to recover those amounts, consistent with its broader obligation under section 6(2)4.1 of O. Reg. 53/05.

OPG submitted that the use of SMR technology over traditional scale reactors does not distinguish the nature of the costs that OPG expects to record to the NDVA from those that it has historically tracked in the account. OPG has been planning and preparing for new nuclear generation facilities – and incurring costs in respect of those activities – throughout the history of the OEB setting payment amounts for OPG. OPG noted that it has incurred, and the OEB has approved, recovery of costs for a range of such planning and preparation activities in multiple prior applications. OPG submitted that the eligible activities that OPG has previously undertaken, and the costs historically recorded to the

[34] Exhibit L / F2-08-Society-13 / p. 1; and Oral Hearing Transcripts / Vol. 1 / pp. 26-27.
[35] OPG Argument-in-Chief / p. 3.
[36] In its reply argument at p. 2, OPG noted that on September 14, 2021, the Government of Ontario posted notice to the provincial Regulatory Registry of a proposed amendment to O. Reg. 53/05, "to include the Darlington SMR project as a regulated facility prescribed within the OEB Act." As discussed below, amendments were filed on November 5, 2021, which come into force on January 1, 2022: see O. Reg. 739/21.

NDVA, are analogous to the type of costs that OPG has incurred and expects to incur in respect of the potential SMR nuclear generating facility at Darlington.[37]

OEB staff, PWU and Society submitted that the SMR-related costs that OPG intends to record in the NDVA are directly associated with the planning and preparation for the development of a proposed new nuclear facility at Darlington. Therefore, in accordance with O. Reg. 53/05, the costs are eligible to be recorded in the account.[38] CME submitted that it does not oppose the recording of SMR-related amounts in the NDVA.[39]

Some intervenors argued that it is not appropriate to record the SMR-related costs in the NDVA.[40] Other intervenors argued that the OEB should reserve its determination on the appropriateness of recording SMR-related costs in the NDVA until such time that OPG seeks disposition of the balance in the account.[41] A few other arguments were also made by intervenors. These arguments are summarized in the following categories: the NDVA is a variance account, there is no proposed new nuclear facility, the OEB should defer consideration until a future proceeding, a new account is required, and a cap on firm financial commitments is appropriate.

Findings

The OEB finds that the SMR-related costs that OPG proposed to record in the NDVA with respect to the planning and preparation for the development of a new SMR facility at Darlington are consistent with the purpose and description of the account and therefore appropriately recorded in the account.

This matter has been complicated by the fact that on November 5, 2021 amendments to certain sections of O. Reg. 53/05 were filed. In particular, sections 5.4(1) and 6(2)4.1 were amended as follows:

> **5.4(1)** Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between,

[37] OPG Reply Submission / pp. 1-3.
[38] OEB Staff Submission on Unsettled Issues / pp. 4-5; PWU Submission / pp. 1-4; and Society Submission / pp. 1-8.
[39] CME Submission / p. 23.
[40] Energy Probe Submission / pp. 4-5; SEC Submission / pp. 4-8; and VECC Submission / pp. 2-5.
[41] AMPCO / CCC Submission / p. 10; Environmental Defence Submission / p. 3; and LPMA Submission / p. 3.

(a) the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs of,

i. planning and preparation for the new facilities,

ii. technology identification for the new facilities, and

iii. design, development and construction of the new facilities; and

(b) the amount of the revenue requirement impacts arising from non-capital and capital costs and firm financial commitments that were included in payments made under section 78.1.

6(2)4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs described in subclauses 5.4 (1) (a) (i) to (iii), to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

Prior to the amendments, sections 5.4(1) and 6(2)4.1 read as follows:

5.4(1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities.

6(2)4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

In addition, "small modular reactor" was added to the definitions section, and any small modular reactors on lands owned by OPG in the Municipality of Clarington (which includes the site of the Darlington Nuclear Generating Station) have been added to the list of prescribed assets in section 2 of the regulation. The amendments come into force January 1, 2022.

The OEB notes that the amended O. Reg. 53/05 requires the OEB to ensure that OPG recovers the prudent capital and non-capital costs and firm financial commitments related to the planning and preparation for the development of proposed new nuclear generation. Prior to the amendments, section 5.4(1) of O. Reg. 53/05 only applied to non-capital costs. The NDVA was therefore originally established to record only the non-capital costs to the extent that the costs are not already reflected in approved payment amounts, in accordance with the then current wording of section 5.4(1) of O. Reg. 53/05.

As noted above, section 5.4(1) has now been amended to (amongst other things) include the revenue requirement impacts of both non-capital and capital costs. However, OPG has not identified any in-service capital additions in 2020, 2021, or during the test period that would attract a revenue requitement. The addition of capital costs to section 5.4(1), therefore, does not appear to be relevant to the OEB's determination in this proceeding. To the extent that OPG does have in-service capital additions that would attract a revenue requirement during the test period, the OEB will review both the eligibility of these costs for the NDVA and the prudence of these costs when OPG seeks disposition for those costs.

The OEB finds that the SMR-related costs that OPG proposed to record in the NDVA are directly related to the planning and preparation for a new nuclear generating facility. This finding is bolstered by the amendments to section 5.4(1), which provide additional detail on the types of costs that are eligible for the NDVA. The costs described by OPG in its application are consistent with the types of costs described in section 5.4(1). OPG's forecast expenditures in this application are for the years 2020 and 2021, and the amendments to O. Reg. 53/05 do not come into force until January 1, 2022. As these expenditures were forecasts, the OEB is not certain if all of these expenditures have (or will) actually take place before the end of 2021. Regardless, it is the OEB's determination that the types of SMR costs described by OPG are eligible for inclusion in the NDVA under either version of O. Reg. 53/05. Therefore, the OEB has a statutory obligation, as established in sections 5.4(1) and 6(2)4.1 of O. Reg. 53/05 to allow the SMR-related costs at issue to be recorded in the NDVA. The recovery of any such costs will be subject to a prudence review at the time that OPG seeks disposition of the balance in the NDVA.

The OEB's findings with respect to the arguments made by intervenors that the OEB should not approve (or defer consideration of) OPG's proposal with respect to recording the SMR-related costs in the NDVA are set out below.

NDVA is a Variance Account Not a Deferral Account

SEC argued that recording costs related to SMRs in the NDVA is inconsistent with the purpose of the NDVA. It treats the NDVA as a deferral account rather than a variance account. SEC noted that there was no forecast of planning and preparation expenditures for the development of an SMR included in OPG's 2017-2021 Payment Amounts proceeding. SEC further stated that while the NDVA does have a monthly reference amount from which variances are calculated, none of the reference amount includes any SMR-related costs. SEC submitted that until OPG has an OEB-approved budget for SMR-related costs, these costs are not recordable in the NDVA and are not recoverable from ratepayers.[42] Energy Probe and VECC made similar arguments to SEC regarding OPG inappropriately treating the NDVA as a deferral account.[43]

In its reply argument, OPG submitted that it is not proposing to treat the NDVA as a deferral account. The previously approved payment amounts include a forecast of new nuclear planning and preparation costs. This forecast is the reference amount against which the NDVA will be reconciled.

OPG submitted that the argument that it should not be allowed to record amounts related to SMR technology because its 2017-2021 payment amounts did not include any SMR-related costs should be rejected. In effect, OPG noted that SEC is asking the OEB to impose a new limit on the NDVA, restricting the account not only to planning and preparation activities, but also to the specific type of reactor technology that OPG was contemplating at the time of the prior payment amounts application. OPG submitted that this proposal is inconsistent with the scope of the NDVA.

OPG submitted that although it does not propose to track the NDVA against a nil amount, it is not aware of a requirement that a variance account must vary against a non-zero amount. There is no legislated requirement in O. Reg. 53/05 that there be a non-zero forecast amount in payment amounts to vary against. OPG stated that its revenue requirement did not include any forecast amounts for new nuclear planning and

[42] SEC Submission / pp. 4-8.
[43] Energy Probe Submission / p. 4; and VECC Submission / p. 2.

preparation activities in two previous proceedings.[44] OPG also stated that several of its long-standing variance accounts record differences between a nil reference amount and actual amounts and have been approved for disposition on that basis in multiple prior proceedings.[45]

Findings

The OEB finds that the NDVA can record variances in actual costs relative to nil forecasts in approved payment amounts. The fact that the NDVA is referred to as a variance account does not mean that the account cannot record variances between actual costs incurred for planning and preparing for new nuclear generation facilities relative to a zero-forecast amount for the same activities. The OEB notes that there is no requirement in O. Reg. 53/05 that there be a non-zero forecast amount in payment amounts in which to record variances against.

The OEB notes that OPG cited previous OPG proceedings in which the revenue requirement did not include any forecast amounts for new nuclear planning and preparation activities.[46] The OEB also notes that OPG has several variance accounts that record differences between a zero-forecast amount and actual amounts, which have been approved for disposition on that basis in prior proceedings.[47] The OEB sees no valid reason why the NDVA should only be eligible to record variances against a non-zero forecast amount.

<u>There is No Proposed New Nuclear Facility Associated with the Recorded Costs</u>

VECC and Energy Probe argued that the NDVA is specifically designed for the limited purpose of capturing cost variances associated with "proposed new nuclear generation facilities" and OPG did not propose any new nuclear generation facilities.[48]

VECC argued that OPG is exploring technologies, potential business partners and trying to determine the economic viability of unknown SMR technologies that OPG may,

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[44] OPG cited its 2011-2012 Payment Amounts proceeding (EB-2010-0008) and its 2014-2015 Payment Amounts proceeding (EB-2013-0321).
[45] OPG Reply Submission / pp. 4-6. OPG cited its Hydroelectric Surplus Baseload Generation Variance Account and the Gross Revenue Charge Variance Account. OPG also noted that its Capacity Refurbishment Variance Account records variances between a nil forecast and actual costs for eligible projects that were not included in the prior rebasing application.
[46] OPG Reply Submission / p. 6.
[47] *Ibid.*
[48] Energy Probe Submission / pp. 4-5; and VECC Submission / pp. 4-5.

or may not, ultimately purchase. VECC further submitted that O. Reg. 53/05 allows for the establishment of a variance account that, at best, may be used to record costs related to approved nuclear facilities for which the costs will ultimately be recovered in regulated payment amounts. It does not anticipate that it be used for the exploration of technologies.[49]

Energy Probe argued that the only new nuclear generation facilities proposed by OPG were the facilities set out in OPG's 2008-2009 Payment Amounts proceeding.[50] Energy Probe stated that the evidence that OPG filed with the Canadian Nuclear Safety Commission (CNSC) with respect to these facilities included three reactor designs, none of which is an SMR. The related environmental assessment report (EA Report) discussed the safety and environmental aspects of the three reactor designs that OPG included in evidence. Energy Probe submitted that the NDVA was established to record cost variances related only to a proposed new nuclear reactor at the Darlington site, as described in the noted EA Report.[51]

In response, OPG submitted that these arguments are flawed as a matter of statutory interpretation, and are inconsistent with the OEB's past approvals with respect to the NDVA. The parties interpret the word "proposed" in section 5.4(1) of O. Reg. 53/05 as imposing a threshold that a new nuclear development project must cross before amounts are eligible to be recorded in the NDVA. OPG submitted that a reasonable plain language reading of section 5.4(1) of O. Reg. 53/05 is that the NDVA records amounts to plan and prepare for a new nuclear generation facility that is "proposed" in the sense of "being considered." In that context, OPG submitted that it is planning and preparing for a proposed project.

OPG stated that the narrow interpretation of the word "proposed" being a project that has the approval of the Board of Directors or shareholder would imply that the very costs necessary to enable a project decision would be ineligible for recovery under section 5.4(1) of O. Reg. 53/05. These include planning and preparation costs that would be typical (and prudent) for evaluating any project, but especially when considering the development of a new nuclear generating facility, prior to an investment decision.[52] OPG also directly responded to VECC's argument that described OPG's

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[49] VECC Submission / pp. 4-5.
[50] EB-2007-0905.
[51] Energy Probe Submission / p. 5.
[52] OPG Reply Submission / pp. 6-8.

SMR-related costs as exploratory and Energy Probe's argument that the only proposed facilities were those related to three reactor designs cited in an EA report.[53]

Findings

Some of the argument that the OEB received on this part of the issue has been impacted by the amendments to the regulation. The new language in section 5.4(1) provides additional detail on what types of costs are eligible for NDVA treatment, specifically costs related to: (a) the planning and preparation for the new facilities (which was included in the previous version of section 5.4(1)); (b) technology identification for the new facilities; and (c) design, development and construction of the new facilities. The OEB finds that the SMR-related costs described in the current application are related to the planning and preparation for a proposed new nuclear generation facility, and more specifically include costs related to technology developer selection. However, the OEB is satisfied that the types of costs described by OPG would also be eligible for inclusion in the NDVA under the pre-amendment version of 5.4(1) as costs related to the planning and preparation for the development of proposed new nuclear generation facilities. The OEB further agrees with OPG's interpretation of the language in section 5.4(1) of O. Reg. 53/05 that "proposed" refers to "being considered."[54]

The OEB finds that OPG's investment in planning and preparation activities for the development of an SMR generating station at the Darlington site are consistent with expectations of the Province of Ontario. In making this determination, the OEB has considered the Ontario government's commitment to SMR technology as demonstrated by the interprovincial SMR-related Memorandum of Understanding to advance SMR development and deployment.[55] The OEB also considered that OPG's 2020-2026 business plan, which underpins the current application and was approved by OPG's Board of Directors, includes SMR-related new nuclear planning and preparation costs.[56] In addition, the OEB considered that in the Minister of Energy, Northern Development and Mines' concurrence with OPG's business plan, he has requested that OPG continue to advance SMR development and deployment.[57] Therefore, OPG's investment in the planning and preparation for an SMR generating station at the Darlington site is with respect to a "proposed" generation facility as evidenced by the Ontario government's support for this spending.

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[53] *Ibid.* / pp. 8-10.
[54] *Ibid.* / pp. 6-8.
[55] Exhibit L / F2-08-Staff-248 / Attachment 1.
[56] OPG Reply Submission / p. 8.
[57] *Ibid.*

<u>The OEB Should Defer its Determination on this Issue</u>

LPMA submitted that, currently, there are too many unknowns with respect to the SMR-related costs for a facility that may or may not be proposed (and may or may not be rate regulated). LPMA submitted that the OEB should defer any decision related to the SMR-related non-capital costs and firm financial commitments to a proceeding when clearance of the account is requested.[58] With respect to any SMR-related costs that may be incurred in 2022 (and beyond), Environmental Defence submitted that these costs should not be deemed eligible for the NDVA as it is too early to resolve the issues around eligibility.[59]

AMPCO / CCC made a similar argument. AMPCO / CCC argued that the OEB should state that it has in no way opined on: (a) whether any SMR-related costs are eligible to be recorded in the NDVA (as set out in section 5.4 of O. Reg. 53/05); and (b) whether the SMR-related costs were prudently incurred. AMPCO / CCC further argued that the OEB should confirm that OPG is taking the risk that the OEB may not accept recovery of SMR-related amounts (capital and / or non-capital) on the basis of eligibility and / or prudence at the time that OPG seeks disposition of any SMR amounts contemplated pursuant to section 6(2)4.1 of O. Reg. 53/05.[60]

In its reply argument, OPG submitted that it expects that the treatment of the NDVA will be consistent with the OEB's typical "record-review-recover" practice for DVAs. OPG would record the amounts in the NDVA that it believes are eligible, and the OEB would review the nature and prudence of those amounts in a subsequent application when OPG proposes to dispose of the balance in the account. OPG submitted that this post-facto review is sufficient and appropriate protection for ratepayers from any potential uncertainty around the treatment of an SMR generating facility at the Darlington site in the future.[61]

Findings

The OEB notes that deferring its findings on the appropriateness of recording SMR-related costs in the NDVA would be inconsistent with the OEB's decision to hear the issue.[62]

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[58] LPMA Submission / p. 3.
[59] Environmental Defence Submission / p. 3.
[60] AMPCO / CCC Submission / p. 10.
[61] OPG Reply Submission / p. 11.
[62] Decision on Issues List / p. 9.

The OEB approves the use of the NDVA to record the SMR-related costs as described in the current application. This approval is granted in the context that the OEB will consider, at the time that OPG seeks disposition of the balance in the account, whether the actual costs incurred (and recorded in the NDVA) are: (a) consistent with the costs described in the current application (or for costs incurred after January 1, 2022 otherwise eligible to be recorded in the account); and (b) prudently incurred. If the actual costs incurred are not found to be prudent (or eligible to be recorded in the NDVA) at the time that OPG seeks disposition of the balance in the NDVA, OPG will bear the cost.

New Account is Required

QMA submitted that there is no evidence that SMRs were contemplated when O. Reg. 53/05 was established. QMA stated that the purpose of the NDVA is to record costs that were incurred in respect of any existing and proposed "new" CANDU reactor models that were being considered at the time. QMA argued that a new account should be established to record SMR-related non-capital costs separately from the NDVA. QMA stated that OPG should be allowed to recover its prudently incurred costs that are captured in this new account.[63]

In response, OPG submitted that a separate account is not needed to address QMA's proposal. OPG stated that it will provide detailed evidence on the actual amounts recorded in the NDVA with respect to the proposed SMR generating facility at the Darlington site when it seeks recovery of the balance recorded in the account.[64]

Findings

The OEB finds that it is not necessary to establish a new account to record SMR-related non-capital costs incurred with respect to the planning and preparation for a new nuclear generating facility. As noted by OPG, detailed evidence on the actual amounts recorded in the NDVA will be provided at the time that OPG seeks disposition of the balance in the account.[65]

[63] QMA Submission / pp. 2-3.
[64] OPG Reply Submission / p. 12.
[65] OPG Reply Submission / p. 12.

A Cap on Firm Financial Commitments is Appropriate

Energy Probe argued that there should be a clear definition of a firm financial commitment, rules on how and when a firm financial commitment can be booked in the NDVA, and a reasonable upper limit on the quantum of firm financial commitments that can be recorded in the account.[66]

In its reply argument, OPG submitted that the cap that Energy Probe proposed to impose on the NDVA is inconsistent with the OEB's obligation under section 6(2)4.1 of O. Reg. 53/05 to ensure that OPG recovers the costs and firm financial commitments to plan and prepare for new nuclear generation. The obligation set out in the regulation is without limitation other than the requirement to demonstrate prudence.[67]

Findings

The OEB finds that there is no valid basis for establishing a cap on the amounts that may be recorded in the NDVA. None of the provisions of O. Reg. 53/05 provide for any such limitation.

4.2 Small Modular Reactor-related Customer Engagement

OPG stated that a requirement that it engage with customers on SMRs as part of its business planning underpinning a payment amounts application is neither appropriate nor practicable. OPG stated that engagement on planning and preparing for an SMR nuclear generating facility at the Darlington site would not have been appropriate, since the decision as to the progress and construction of an SMR is a system planning decision that rests with the Minister of Energy.

OPG stated that an SMR at the Darlington site is necessarily subject to a range of policy decisions and regulatory requirements. While OPG would own the facility, the major policy questions related to such a facility, including the IESO’s determination of the system need, will not ultimately be made by OPG. Similarly, decisions around the configuration and construction of an SMR nuclear generating facility at the Darlington site would be subject to regulatory approval by the CNSC. CNSC requirements include mandatory public and Indigenous community engagement activities.

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[66] Energy Probe Submission / p. 6.
[67] OPG Reply Submission / pp. 10-11.

OPG noted that, in addition to the above considerations, customer engagement on SMRs in the context of the current application would not have been practicable. At the time OPG was developing its customer engagement process that informed the business planning underpinning this application, the development of such a facility was not being explored by OPG.[68] OEB staff and PWU agreed with OPG that the consideration of SMRs as part of the current application's customer engagement would not have been practicable.[69] OEB staff also submitted that no OEB-directed customer engagement with respect to SMRs is necessary going forward.[70]

PWU, LPMA, OAPPA and CME submitted that OPG should engage customers with respect to SMRs in the future.[71]

CME submitted that OPG should consult with customers regarding SMR development. While CME acknowledged that the ultimate decision whether to go ahead with SMR belongs to the Minister of Energy, SMRs are for the benefit of ratepayers. OPG and the Minister of Energy would benefit by canvassing customer views on SMRs prior to making any decisions that could affect Ontario's energy landscape for decades.[72]

In its reply submission, OPG submitted that there will be appropriate engagement on SMR generating facilities in the coming year, and OPG will be part of that larger discussion. However, OPG submitted that there would be no practical scope for any additional customer engagement in connection specifically with its business planning.[73]

LPMA submitted that OPG should engage customers on several aspects of SMRs including, but not limited to, the potential cost of power produced, whether the Darlington site is the optimal location, what alternatives to SMR are available and whether such a facility should be rate regulated.[74]

In response, OPG submitted that the issues raised by LPMA are all system planning and policy matters that ultimately rest with the Minister of Energy, and none of these issues are within the scope of OPG's business planning process. Accordingly, OPG

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[68] OPG Argument-in-Chief / pp. 5-6.
[69] OEB Staff Submission on Unsettled Issues / p. 6; and PWU Submission / p. 6.
[70] OEB Staff Submission on Unsettled Issues / p. 6.
[71] PWU Submission / p. 6; LPMA Submission / p. 4; OAPPA Submission / p. 4; and CME Submission / p. 23.
[72] CME Submission / p. 23.
[73] OPG Reply Submission / p. 13.
[74] LPMA Submission / p. 4.

submitted that it would not be appropriate for the OEB to mandate that OPG conduct customer engagement on these topics.[75]

OAPPA submitted that the OEB should order OPG (and provide advance warning to the Ministry of Energy) that plans for SMR generation must include investments in setting the stage for community acceptance via in-depth stakeholder consultation.[76]

In its reply argument, OPG submitted it is not its role, or the role of the OEB, to send warnings to the Ministry of Energy, nor dictate the public consultations that the Government of Ontario and other stakeholders should conduct in respect of energy planning in Ontario.[77]

Findings

The OEB will not direct OPG to conduct additional customer engagement on SMR-related costs and activities.

The OEB finds that OPG's proposed customer engagement process is appropriate. It could be misleading for OPG (alone) to conduct SMR-specific customer engagement given the final decision regarding the construction of an SMR generating facility is a system planning decision that rests with the Minister of Energy. Significant engagement would also be required by the CNSC for any new nuclear facilities.

4.3 Small Modular Reactor-related Reporting and Record Keeping Requirements

OPG noted that the approved settlement proposal includes a range of reporting and record keeping requirements, some of which encompass the NDVA and, should it be legislated as a prescribed facility, a potential SMR nuclear generating facility at the Darlington site.

OPG noted that the required reporting is to be posted on the OEB's and OPG's websites, and includes an extensive nuclear performance reporting scorecard that contains discrete performance measures for the company's prescribed nuclear facilities, with separate annual reporting for each of the nuclear generating stations. In addition,

[75] OPG Reply Submission / p. 14.
[76] OAPPA Submission / pp. 2-4.
[77] OPG Reply Submission / pp. 14-15.

the balance of the NDVA will continue to be included in quarterly reporting on OPG's DVAs. Finally, OPG will annually report on the prior year's capital in-service additions and construction work in progress balances for prescribed facilities by April 30 each year. OPG submitted that the noted reporting requirements are appropriate and sufficient.[78]

OEB staff and PWU agreed with OPG that no incremental reporting requirements are necessary with respect to SMR-related costs.[79]

AMPCO / CCC and LPMA submitted that OPG should separately track and report on SMR-related costs.[80] AMPCO submitted that OPG should publicly report, on an annual basis, all SMR spending (capital and / or non-capital) for all years 2020 and onwards (with the spending fully itemized by cost type).[81]

In its reply argument, OPG submitted that the reporting requirements that AMPCO / CCC propose reflect a level of granularity that exceeds OPG's typical reporting requirements. The level of granularity sought by AMPCO / CCC would also require an approved basis upon which to breakdown the progress of the potential SMR project, which has been neither developed nor approved.

OPG stated that a central function of its reporting and record keeping requirements is to provide the OEB and ratepayers with a view of OPG's actual performance at its regulated facilities on a range of operational and financial outcomes relative to the plans presented to, and approvals made by, the OEB. This allows the OEB and other parties to assess how OPG is performing and the outcomes it is achieving relative to those plans. In this case, no SMR project or costs have been proposed to, or will have been approved by, the OEB in this proceeding. Consequently, there are no proposed outcomes to track against, nor any amounts being collected from customers to reconcile against.[82]

Findings

The OEB finds the list of reporting and record keeping requirements approved in the settlement proposal[83] to be sufficient and comprehensive given the scope of OPG's

[78] OPG Argument-in-Chief / pp. 6-7.
[79] OEB Staff Submission on Unsettled Issues / p. 7; and PWU Submission / p. 7.
[80] AMPCO / CCC Submission / p. 10; and LPMA Submission / p. 4.
[81] AMPCO / CCC Submission / p. 10.
[82] OPG Reply Submission / p. 16.
[83] Settlement Proposal / Appendix A.

activities for the next five years. The OEB agrees with OPG that the objective of reporting is to provide the OEB and ratepayers a view of OPG's actual performance relative to the plans presented to, and approvals made by, the OEB at its regulated facilities.[84] The OEB finds that no additional SMR-specific reporting requirements are necessary.

[84] OPG Reply Submission / p. 16.

5 D2O PROJECT-RELATED ISSUES

The issues that are not settled related to the D2O Project, which were the subject of examination at the oral hearing held between August 4 and August 6, 2021, are as follows:

a. Whether the proposed test period in-service additions for the D2O Project are reasonable

b. Whether the deferral and variance account balances associated with the D2O Project are reasonable.

5.1 Reasonableness of D2O Project-related In-service Additions

The D2O Project involved construction of a seismic dike and a concrete and steel building to house the tanks and equipment necessary to store various streams of heavy water and handle, clean, test and store the drums used to transport heavy water.[85]

The D2O Project is designed to store tritiated heavy water from Darlington nuclear units undergoing refurbishment and to support the operations of the Tritium Removal Facility (TRF) to remove tritium from heavy water, which is necessary to operate Ontario's nuclear fleet. Until the last Darlington nuclear unit is refurbished, 1,700 m^3 of the 2,100 m^3 of heavy water storage contained in the D2O Project will be used to support the DRP; once the DRP is complete, this storage capacity will support the entire Ontario nuclear fleet including the possible storage of heavy water from the planned Pickering shutdown. The remaining heavy water storage capacity, 400 m^3, supports ongoing operations at Darlington and the TRF.[86]

On June 22, 2012, OPG issued a purchase order to Black & McDonald (B&M) to begin work on the D2O Project.[87] In the spring of 2013, site preparation work was started.[88] The D2O Project was substantially complete in November 2019 and declared capable of receiving heavy water in March 2020.[89] Final commissioning of the D2O Project was completed in November 2020 for the Primary Heat Transport (PHT) system and in early 2021 for the moderator and TRF product and feed systems. OPG's completion of

[85] Exhibit D2 / Tab 2 / Schedule 10 / pp. 14-15.
[86] *Ibid.* / pp. 5 and 9.
[87] *Ibid.* / p. 47.
[88] Exhibit D2 / Tab 2 / Schedule 10 / Attachment 4 / p. 3.
[89] Exhibit D2 / Tab 2 / Schedule 10 / p. 102; and Exhibit D2 / Tab 2 / Schedule 10 / Attachment 4 / p. 8.

commissioning allowed the D2O Project to begin accepting heavy water from Unit 3 on November 26, 2020.[90]

The actual total cost of the D2O Project is $510 million, consisting of $509.3 million in capital and $0.7 million in OM&A for removal costs incurred in 2013.[91] Of the $509.3 million in capital cost, OPG noted that $14.6 million was approved for inclusion in rate base in 2014 and is reflected in the rate base approved in OPG's 2017-2021 Payment Amounts proceeding.[92]

In its application, OPG requested approval to incorporate the remaining $494.7 million of the D2O Project capital cost into rate base.[93] OPG also requested approval for recovery of the related portion of the Capacity Refurbishment Variance Account (CRVA) balance, as at December 31, 2019, related to the D2O Project.[94]

The D2O Project cost estimates provided to OPG's senior management as the basis for funding approval between 2012 and 2018 are as follows[95]:

Table 8: D2O Project Cost Estimates

	Date	Estimate ($ millions)
Full Definition Release	June 2012	108.1
Partial Execution Release	August 2012	108.1
Full Execution Release	May 2013	110.0
Superseding Execution Release	March 2015	381.1
Superseding Execution Release	February 2018	510.0

OPG submitted that it acted prudently with respect to the D2O Project and that the costs it seeks to recover for the project reflect the true cost to design, engineer, procure materials for, construct, and commission the D2O Project.[96]

[90] OPG Argument-in-Chief / p. 31.
[91] Exhibit D2 / Tab 2 / Schedule 10 / p. 1.
[92] *Ibid.*
[93] *Ibid. /* p. 12. The $494.7 million capital cost for which OPG seeks approval to close to rate base includes $160 million in 2016, $320.9 million in 2019, and $13.8 million in 2020.
[94] Exhibit H1 / Tab 1 / Schedule 1 / p. 20.
[95] Exhibit L / D2-02-SEC-094 / p. 1.
[96] OPG Argument-in-Chief / p. 11.

OEB staff and some intervenors argued for disallowances ranging from $160 million to $400 million due to OPG's imprudent management of the D2O Project.[97]

OEB staff and intervenor submissions on the D2O Project are summarized in the following categories: prudence review, prudence of D2O Project costs, and allocation of D2O Project costs. OPG's responses to the submissions of parties are summarized in the same categories. Submissions with respect to the timing of D2O Project in-service additions as reflected in the CRVA are discussed in section 5.2 of the Decision.

Prudence Review

O. Reg. 53/05 paragraph 6(2)4 stipulates that the OEB must allow OPG to recover DRP-related costs so long as they are prudent: "[t]he Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project … including, but not limited to, assessment costs and pre-engineering costs and commitments … if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made."

OPG submitted that the OEB's traditional approach to prudence reviews was set out in RP-2001-0032 and affirmed by the Ontario Divisional Court and the Court of Appeal in *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72 (Div. Ct.); reversed on other grounds, (2006), 41 Admin L.R. (4th) 69 (Ont. Ct. of Appeal). OPG stated that the OEB's traditional approach to prudence reviews has considered the circumstances that were known or ought to have been known to the utility at the time the decision was made, not used hindsight, and employed a retrospective factual inquiry where the evidence must be concerned with elements that could or did enter into the decision at the time it was made. OPG submitted that, while the Supreme Court held in *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, that the OEB is not required to continue using this standard in prudence reviews, its decision does not suggest that the OEB should abandon its previously articulated prudence standard.

OPG also stated that in that decision, the Supreme Court held that applying a presumption of prudence would conflict with the burden of proof in the OEB Act. OPG stated that its arguments do not rely on a presumption of prudence. OPG submitted that

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[97] OEB Staff Submission on Unsettled Issues / pp. 19-20; AMPCO / CCC Submission / p. 11; CME Submission / p. 3; Energy Probe Submission / p. 7; LPMA Submission / p. 5; SEC Submission / p. 4; and VECC Submission / p. 7.

the continued application of the OEB's historical approach to prudence review is appropriate in this proceeding.[98]

CME and SEC submitted that OPG does not benefit from the presumption of prudence.[99] SEC submitted that the legal obligation (both onus and burden) on OPG to demonstrate that the $510 million cost of the D2O Project is prudent is an important foundation for the OEB's consideration of this issue. SEC further stated that OPG is required to provide sufficient evidence of prudence so that the OEB can make a finding with respect to just and reasonable rates. While the OEB has broad discretion with how it assesses OPG's evidence in support of prudence, SEC submitted that what the OEB must do at all times is to adhere to the terms of the statute from which all of its powers and mandate arise.[100]

SEC argued that there are five main ways that OPG can discharge the burden of showing that a capital cost was prudently incurred: (a) benchmarking the cost of the project against a similar project; (b) providing evidence that the project unfolded as forecast in accordance with a well-constructed plan; (c) providing external evidence that at each stage of the project, OPG applied best practices to make decisions; (d) providing an independent review of the project, its development, execution, and final costs to demonstrate that no material imprudent actions or decisions were taken; and (e) providing explanations as to why each of the problems experienced did not involve imprudence. SEC described, why, in its view, OPG has not discharged its burden of proof.[101]

With respect to the use of hindsight in determining prudence, OEB staff submitted that no hindsight is required to identify imprudence. The evidence of imprudence is found mainly in contemporaneous accounts of the project, especially reports prepared for OPG's Board of Directors by Modus Strategic Solutions Canada and Burns & McDonnell Canada (Modus / Burns).[102]

CME submitted that while the OEB must be cautious not to apply hindsight in making determinations about prudence, the review properly takes into account both what OPG knew, or ought to have known, at the time that a decision was made.[103]

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[98] OPG Argument-in-Chief / pp. 9-10.
[99] CME Submission / p. 7; and SEC Submission / p. 15.
[100] SEC Submission / pp. 15-16.
[101] *Ibid.* / pp. 17-20.
[102] OEB Staff Submission on Unsettled Issues / p. 16.
[103] CME Submission / p. 7.

SEC submitted that it is not hindsight to review what actually happened with respect to the D2O Project in an attempt to determine what went wrong and applying the knowledge that something adverse did occur. The outcome – a 400% cost overrun – is what frames the question about the capital spending. SEC further submitted that the outcomes of the D2O Project are known to the OEB, and they are the framework within which the OEB can assess whether the capital costs for this project were prudent. Using the facts that are known to assess what happened in the past is not the application of hindsight; it is a lens.[104]

In response, OPG acknowledged that it has the burden of proof to establish that the costs it seeks to include in rate base are reasonable. OPG's legal position on the use of hindsight in the application of the prudence standard is that the project should be evaluated based on what was known or reasonably should have been known at the time of the project. Further, OPG submitted that hindsight is to be avoided when evaluating the reasonableness of actions taken because hindsight involves information that was unknown and not reasonably knowable at the time the action was taken. Outcomes are the results of actions and establish neither prudence nor the lack of prudence.[105]

Findings

The OEB must find the D2O Project costs to be prudent before those costs can be placed into rate base. In a utility context, "prudent cost" has been found to be synonymous with "reasonable cost."[106]

The onus is on OPG to prove prudence. The OEB agrees with OPG that there is no presumption of prudence in assessing the costs for a capital addition to be added to rate base.

The OEB has not used hindsight in this decision, even though there is no prohibition against the use of hindsight depending on the circumstances. The Supreme Court of Canada has provided guidance as to the appropriate approach for the use of hindsight to assess the prudence of costs incurred by a utility: "[t]he question of whether it was reasonable to assess a particular cost using hindsight should turn instead on the circumstances of that cost."[107]

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[104] SEC Submission / p. 16.
[105] OPG Reply Submission / pp. 19, 24-25.
[106] *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission),* 2015 SCC 45, paras. 34-35.
[107] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, para. 104.

There is no bright line to define what is hindsight and what is not. In any case, the OEB did not use hindsight because it has considered what would have been prudent acts of management at the time the decisions were made by OPG.

It appears that the principal source of concern for OPG is that the reliance on project estimates involves the potential use of hindsight. For example, in OPG's view it would be inappropriate for the OEB to rely on OPG's 2013 Full Execution Release, or the 2015 Superseding Execution Release, or the 2018 Superseding Execution Release to establish the prudent cost of completing the D2O Project. Thus, any increase in costs over these estimates could somehow be evidence of improvident management forcing a reduction in the amount added to rate base in keeping with the prior estimate. OPG emphasized that the project pathway was a learning experience with lessons learned along the project timeline.

The OEB does not accept the general premise put forth by several parties that the significant overspending relative to the D2O Project release estimates represents the key factor in establishing the quantum of costs that should be disallowed due to imprudent management. The OEB also does not accept that the final cost of the D2O Project proposed to be added to rate base would have been expended regardless of the problems and delays that occurred. The OEB finds that the failure of the estimates to accurately predict cost outcomes is a symptom of the preventable mistakes that the OEB has quantified herein. The extent of the underestimates is one factor negating the approval of $510 million as a prudent cost for the D2O Project.

Prudence of D2O Project Costs

As noted previously, OPG submitted that it acted prudently with respect to the D2O Project and that the costs it seeks to recover for the project reflect the true cost to design, engineer, procure materials for, construct, and commission the D2O Project.[108] PWU and the Society agreed with OPG that the costs of the D2O Project were prudently incurred (and therefore are recoverable from ratepayers).[109]

AMPCO / CCC, CME, Energy Probe, LPMA, SEC, VECC and OEB staff argued that the D2O Project costs were not prudently incurred and a disallowance is appropriate.[110]

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[108] OPG Argument-in-Chief / p. 11.
[109] PWU Submission / pp. 10-11; and Society Submission / p. 5.
[110] OEB Staff Submission on the Unsettled Issues / pp. 9-20; AMPCO / CCC Submission / pp. 11-50;

Some of the arguments that the parties made are based on the commentary set out in certain Modus / Burns reports[111] and the Auditor General's 2018 Report. For example, some parties cited[112] Modus / Burns that OPG's Projects and Modifications (P&M) group:

> … was completely overwhelmed in trying to manage Campus Plan Projects – in particular, the two largest of these projects, the D2O Storage Facility and Auxiliary Heat Steam Plant...[113]

A summary of the arguments made by the parties supporting their position that the D2O Project costs were not prudently incurred is set out below.

- OPG moved forward with the D2O Project in the absence of sufficient design / engineering.[114]

- OPG's initial contracting practice and contractor selection (B&M) was imprudent.[115]

- OPG's poor project management and contractor oversight led to imprudent costs being incurred.
    - OPG's P&M group had insufficient training and experience to manage the D2O Project.[116]
    - OPG's P&M group lacked experience with the Engineer, Procure and Construct (EPC) contracting model.[117]

CME Submission / pp. 8-22; Energy Probe Submission / pp. 6-12; LPMA Submission / pp. 4-6; SEC Submission / pp. 9-39; and VECC Submission / pp. 6-7. Note that LPMA supported the arguments of AMPCO / CCC (D2O Project cost disallowance) and SEC (Bates White Report), VECC supported the arguments of AMPCO / CCC, Energy Probe and SEC, and SEC supported the arguments of AMPCO / CCC (D2O Project was overbuilt).

111 Exhibit L / D2-02-Staff-105 / Attachment 2. Parties largely reference the Modus / Burns 2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors, and to a lesser extent the Modus / Burns Supplemental 2nd Quarter 2014 Report to the Nuclear Oversight Committee.

112 OEB Staff Submission on Unsettled Issues / pp. 12-13; CME Submission / p. 13; and SEC Submission / p. 23.

113 Exhibit L / D2-02-Staff-105 / Attachment 2 / p. 176.

114 Energy Probe Submission / p. 8; and SEC Submission / p. 27.

115 OEB Staff Submission on the Unsettled Issues / pp. 11-12; AMPCO / CCC Submission / p. 24; CME Submission / pp. 8-12; Energy Probe Submission / p. 7; and SEC Submission / pp. 28-29.

116 OEB Staff Submission on the Unsettled Issues / pp. 13-14; AMPCO / CCC Submission / pp. 23-24; CME Submission / pp. 12-13; Energy Probe Submission / p. 10; and SEC Submission / pp. 22-24.

117 Energy Probe Submission / p. 10; and SEC Submission / p. 26.

  - OPG's P&M group incorrectly applied a "hands-off" approach to its contractor oversight.[118]
  - The P&M group intentionally minimized the baseline cost estimates for the D2O Project.[119]
  - The P&M group's failure to report cost and schedule variances constrained options available during the duration of the D2O Project.[120]

- OPG imprudently accepted design changes from its second contractor (CanAtom) that resulted in cost increases and also did not impose a cap on the total project cost at the time of the proposed redesign.[121]

- The D2O Project was overbuilt. OPG only considered one size for the project being the largest and most expensive version possible.
  - Uncontrolled scope changes were made to achieve operational flexibility, which was not needed for the purposes of DRP-related storage.[122]
  - OPG did not properly consider potential alternatives (i.e. constructing the D2O Project outside the protected area, utilizing the flexibility of the Heavy Water Management Building, Pickering and Bruce, and constructing the D2O Project on-grade).
  - OPG did not optimize tank volumes.
  - OPG did not provide economic evaluation of increased scope.[123]

In its reply argument, OPG provided detailed responses to the submissions of parties with respect to its management of the D2O Project and supporting its position that the D2O Project was not overbuilt.[124] These responses are summarized below.

- It was appropriate to release funding for the D2O Project when engineering for the project was in its early stages to allow certain construction activities to begin in parallel with design and site preparation activities and to enable the procurement of long lead materials.[125]

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[118] OEB Staff Submission on the Unsettled Issues / pp. 12-13; AMPCO / CCC Submission / p. 21; CME Submission / p. 13; Energy Probe Submission / pp. 6-12; LPMA Submission / pp. 4-6; SEC Submission / pp. 9-39; and VECC Submission / pp. 6-7.
[119] AMPCO / CCC Submission / pp. 35-36; CME Submission / p. 14; and SEC Submission / p. 25.
[120] OEB Staff Submission on the Unsettled Issues / pp. 15-16; AMPCO / CCC Submission / p. 37; CME Submission / pp. 17-18; and SEC Submission / p. 24.
[121] AMPCO / CCC Submission / pp. 39-44.
[122] AMPCO / CCC Submission / pp. 19-22.
[123] *Ibid.* / pp. 19-34.
[124] OPG Reply Submission / pp. 27-77.
[125] *Ibid.* / p. 100.

- Both proponents that responded to the initial work request were viewed as technically qualified to undertake the D2O Project and a different contractor would not have changed the D2O Project (and it was the project, as fully elaborated, that drove the cost).[126]

- Parties have mischaracterized the meaning of (or drawn the wrong conclusions from) the comments in the Modus / Burns reports with respect to OPG's management of the D2O Project.
  - Despite the many criticisms of both B&M and OPG's performance early in the life the project, Modus / Burns concluded that the challenges they identified did not result in increased costs or even the potential to increase costs on the D2O Project.[127]

- The redesign proposed by CanAtom, and accepted by OPG, did not result in cost increases. Instead, the cost increase experienced was primarily driven by increased construction costs incurred to complete the project.[128]

- The D2O Project is not overbuilt. The D2O Project was constructed to meet the needs of the DRP and the ongoing operational needs of the Darlington station and the TRF.
  - DRP and operational storage needs are not different. If OPG had constructed two facilities to store heavy water, one for refurbishment and one for operational needs, both buildings would have required many of the same systems.
  - Planned scope elaboration is not scope creep. The D2O Project always included elaboration of its scope as an initial step.
  - OPG properly considered alternatives and rejected the alternatives for valid reasons.
  - OPG elected to use smaller tanks (rather than larger tanks) to reduce the risk of downgrading a large quantity of heavy water and allow for easier inspection and maintenance.[129]

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[126] *Ibid.* / pp. 54-58.
[127] *Ibid.* / pp. 58-67.
[128] *Ibid.* / pp. 71-73.
[129] *Ibid.* / pp. 31-54.

OPG filed an independent expert report prepared by Bates White Economic Consulting (Bates White) (the Bates White Report)[130] that OPG stated supports its position that the amount it seeks to recover is a realistic estimate of the true D2O Project cost.[131]

OPG submitted that the Bates White Report shows that, assuming "perfect knowledge" with respect to project scope, design requirements, and actual site conditions encountered, statistically, the most probable cost estimate for constructing the D2O Project would have been calculated at $512.1 million prior to the start of construction.[132]

OEB staff, AMPCO / CCC, CME, Energy Probe and SEC (as supported by other parties) provided arguments with respect to the Bates White Report as summarized below.

- The Bates White Report does not provide any opinion on prudence, which is what the OEB must assess in the current proceeding.[133]

- The Bates White Report does not provide any assistance to the OEB with respect to whether the design of the D2O Project was the appropriate alternative to pursue.[134]

- Bates White's failure to shield itself from the knowledge of OPG's growing cost estimates was a methodological flaw that calls into question the conclusions of the report.[135]

- The Bates White Report is based on questionable assumptions.
    - It reflects the inclusion of contingency even though with perfect knowledge there is no uncertainty.
    - It uses a 39% labour productivity rate when OPG's labour productivity at Darlington is 53%-55%.[136]
    - It uses a four-person crew when OPG stated that a three-person crew is a reasonable average.[137]

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130 Undertaking J3.4.
131 OPG Argument-in-Chief / p. 11; and OPG Reply Submission / p. 78.
132 Undertaking J3.4.
133 OEB Staff Submission on Unsettled Issues / p. 16; AMPCO / CCC Submission / p. 46; CME Submission / p. 19; Energy Probe Submission / pp. 11-12; and SEC Submission / p. 36.
134 AMPCO / CCC Submission / p. 46; CME Submission / p. 21; and SEC Submission / p. 36.
135 OEB Staff Submission on Unsettled Issues / p. 17; and AMPCO / CCC submission / pp. 46-47.
136 SEC Submission / pp. 32-34; and CME Submission / pp.19-20 (labour productivity rate only).
137 CME Submission / p. 20.

- The Bates White Report has other serious problems.
  - It includes undocumented analysis with respect to the amount of pipe required by the design drawings.
  - Bates White appears to always conclude that the amount their utility clients spent, or think should have been spent, is the reasonable cost of the project.[138]

In its reply argument, OPG provided detailed responses to the submissions of parties with respect to the Bates White Report as summarized below:[139]

- The prudence of a project's costs is ultimately a matter of weighing evidence and rendering judgment based on it. Prudence is properly determined by the OEB and not by outside experts.

- OPG did not request that Bates White assess project alternatives as it had been engaging external experts to assist in assessing options for storing additional heavy water at Darlington since 2014 (and OPG provided a list of external assessments of alternatives that were filed in the current proceeding).

- The OEB should ignore the parties' speculative claims of bias and rely on the responses from Bates White provided at the oral hearing.[140]

- The criticisms of the assumptions used in the Bates White Report are based either on misunderstanding the Bates White methodology or mispresenting the methodology.
  - It was appropriate to include contingency amounts in the cost estimate as Bates White assumed perfect knowledge of what would be built and site-specific conditions but did not assume perfect knowledge of ordinary construction risks.
  - The criticisms of the productivity rate rest on the erroneous proposition that OPG's internal productivity rate (53%-55%) for construction projects at Darlington are higher than the productivity factor used by Bates White. The 53%-55% productivity factor is the productivity assumed for regular work in the Darlington station, not for construction projects within the Darlington protected area.

[138] SEC Submission / pp. 34-35.
[139] OPG Reply Submission / pp. 22-24, 78-97.
[140] OPG referred to the testimony of Bates White at Oral Hearing Transcripts / Vol. 3 / pp. 117-122.

  - The estimate does not use an average crew size. Instead, the estimate is based on the crew sizes required to execute each of the specific tasks used to build-up the Bates White project cost estimate.

- There is no support for the statement that Bates White always concludes in favour of its client.[141]

As previously noted, OEB staff and some intervenors argued for disallowances ranging from $160 million to $400 million due to OPG's imprudent management of the D2O Project.[142]

AMPCO / CCC, Energy Probe, LPMA, SEC, and VECC submitted that the OEB should order a $200 million disallowance to address OPG's imprudent management of the D2O Project and overbuilding the facility. The proposed $200 million disallowance for the D2O Project is based on the findings made by the OEB in OPG's 2017-2021 Payment Amounts proceeding[143] with respect to the disallowance applied to the Auxiliary Heating System (AHS) and Operations Support Building (OSB) projects, which were also managed by the P&M group.[144] In the noted decision, the OEB disallowed 50% of the variance between the first execution business case and final claimed cost for each project. The OEB determined that it would allow 50% of the increased cost on account of increased scope and disallow 50% of the increased cost to account for poor management.[145]

As was the case with the disallowance applied to the AHS and OSB projects, AMPCO / CCC, Energy Probe, LPMA, SEC, and VECC argued that it is appropriate to account for OPG's imprudent management of the D2O Project by disallowing 50% of the difference between the 2013 Full Execution Release ($110 million) and the final claimed cost ($510 million). This results in a $200 million disallowance to the D2O Project (i.e. 50% of the $400 million cost overrun).[146]

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141 OPG Reply Submission / pp. 22-24, 78-97.
142 OEB Staff Submission on Unsettled Issues / pp. 19-20; AMPCO / CCC Submission / p. 11; CME Submission / p. 3; Energy Probe Submission / p. 7; LPMA Submission / p. 5; SEC Submission / p. 4; and VECC Submission / p. 7.
143 EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 20-22.
144 AMPCO / CCC Submission / p. 11; Energy Probe Submission / p. 7; LPMA Submission / p. 5; SEC Submission / p. 4; and VECC Submission / p. 7.
145 EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 21-22.
146 AMPCO / CCC Submission / p. 11; Energy Probe Submission / p. 7; LPMA Submission / p. 6; SEC Submission / p. 4; and VECC Submission / p. 7.

OEB staff submitted that applying the same 50:50 split to the cost overrun, as was applied to the AHS and OSB projects, to the D2O Project would be too high, as it would not take into account OPG's successful offloading of $77 million in costs to CanAtom (which was one of OPG's contractors on the project). Therefore, OEB staff submitted that 40% of the cost overrun should be attributable to imprudent management. This results in a disallowance of $160 million (i.e. 40% of the $400 million cost overrun).[147]

CME submitted that the OEB should order a $400 million disallowance, which is equal to the entire cost overrun in excess of the 2013 Full Execution Release estimate. While the OEB disallowed 50% of the difference between the full execution release and the final cost for the AHS and OSB projects, CME submitted that the full disallowance is warranted for the D2O Project. CME stated that increasing scope is not mutually exclusive with imprudent management. Instead, it is a symptom.[148]

In its reply argument, OPG submitted that the disallowances sought by OEB staff and some intervenors are not appropriate as it has demonstrated that it acted prudently throughout the life of the D2O Project.

OPG argued that the OEB should reject invitations to adopt a formula-based approach to determining a disallowance as a substitute for reviewing the prudently incurred costs of the D2O Project. OPG stated that applying the formula used for calculating the disallowance applied to the AHS and OSB projects in OPG's 2017-2021 Payment Amounts proceeding is unnecessary because of the detailed body of evidence that OPG has provided on the D2O Project.[149]

OPG also submitted that the parties advocating for formulaic disallowances assume that the 2013 Full Execution Release provides a proper initial baseline for project costs. OPG submitted that this assumption is incorrect. OPG stated that its early estimates were incorrectly categorized as more mature estimates (Class 2) than they actually were (Class 5). OPG submitted that while construction challenges justifiably caused the D2O Project final cost to be $510 million, the 2015 Superseding Execution Release ($381.1 million) was the first document that reflected the project's full scope and thus represents a more appropriate starting point for assessing the project's final cost.

[147] OEB Staff Submission on Unsettled Issues / pp. 17-20.
[148] CME Submission / pp. 3 and 22.
[149] OPG Reply Submission / pp. 97-99.

OPG submitted that the recommended disallowances are inconsistent with the evidence and the evidence supports full recovery of the D2O Project costs.[150]

Findings

As was noted previously in the Decision, the OEB does not accept the general premise put forth by some parties that the significant overspending relative to the release cost estimates is the key factor in establishing the quantum of costs that should be disallowed due to imprudent management. The OEB will not use the release cost estimates to determine a pro-rata split of overspending, such as a 50:50 split or 60:40 split of the variance. The OEB also does not accept that the final cost of the D2O Project to OPG of $510 million would have been expended regardless of the problems and delays that accompanied the project.

The OEB makes a permanent rate base disallowance to the $509.3 million total cost that OPG proposes to add to rate base for the D2O Project, comprised of the following:

1. A $94 million disallowance
2. A disallowance of the carrying costs incurred related to the in-service delay from May 2017 to March 2020.[151]

Disallow $94 million as a Permanent Rate Base Reduction

The evidence indicates that $115.3 million had been incurred by OPG when it terminated B&M in October 2014. This is comprised of $114 million of capital costs and $1.3 million of OM&A costs ($0.6 million of the OM&A cost was written off).[152] The OEB has assessed the value of the capital work completed as of October 2014 at no more than $20 million, which includes the $14.6 million already in rate base.[153] The OEB finds that the $114 million capital cost was not prudently incurred and permanently reduces the balance of allowed capital costs to $20 million as of October 2014.

The OEB considers the October 2014 termination date of B&M to be a pivotal time for the D2O Project. It preceded the retention of CanAtom, the 2015 Superseding

[150] *Ibid.* / pp. 100-104.
[151] As discussed in section 5.2, the OEB has determined that OPG's proposed partial in-service additions in 2016 and 2019 for the D2O Project are appropriately considered in-service in March 2020.
[152] Exhibit L / D2-02-Staff-162.
[153] Exhibit D2 / Tab 2 / Schedule 10 / p. 1. OPG placed $14.6 million in-service in October 2014 for the D2O Project, which is reflected in the rate base approved in OPG's 2017-2021 Payment Amounts proceeding.

Execution Release ($381.1 million) and the redesign of the building. At that time, OPG had incurred $114 million of capital costs, but what did ratepayers "get" for $114 million to justify the inclusion in rate base and recovery in payment amounts as a just and reasonable cost?

Instead of a completed D2O Project as of October 2014, $114 million had been spent for what the OEB considers site preparation and design work. In fact, the D2O Project was already over budget and behind schedule. The OEB is not convinced that the costs included prior to October 2014 were prudently incurred. In making this conclusion, the OEB has been influenced by the following chronological evidentiary record for the D2O Project.

The OEB has considered the 2011 Developmental Release, the 2012 Partial Execution Release and the 2013 Full Execution Release which preceded B&M's termination. In particular, the 2012 Partial Execution Release included an approved budget of $27.3 million for the completion of both the detailed design and site preparation phases by September 2013 which the OEB considers a prudent budget ceiling for "fit for purpose" spending.[154]

Six months after B&M was terminated, the 2015 Superseding Execution Release indicated the following.

Table 9: Overview of Project Phase Status in 2015 Superseding Execution Release

Project Phase	Project Status	Completion Date
Detailed Design	In Progress	May 2015
Site Preparation	Complete	April 2014

This subsequent 2015 Superseding Release was described by OPG as "a more appropriate starting point" for assessing the project's final costs.[155] A review of the budget after 2014 points to additional costs to either redo the work of B&M and its subcontractors, or execute work that was supposed to have been performed as of October 2014. This bolsters the OEB's finding that OPG failed to prove that the $94 million was prudently incurred up to the termination of B&M.

[154] Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2N / pp. 4-5, 17.
[155] OPG Reply Submission / p. 102.

The OEB has applied its judgement in attributing a $20 million value to ratepayers for work completed as of October 2014 based on the evidence available, by considering:

- OPG approved budgets before October 2014
- The objectives OPG should have ensured were reflected in the contract and performance of B&M
- The stage of completion of the D2O Project
- Interest accrued on lifetime-to-date expenditures
- OPG approved budgets after October 2014

OPG appears to ascribe value to incurred costs, claiming there were "valuable" lessons learned for the remainder of the DRP.[156] The OEB does not find value to ratepayers for costly lessons learned during the early stages of the D2O Project. The OEB finds that any valuable lessons learned in executing the D2O Project may be evident in executing the DRP but cannot be monetized to justify the costs incurred in the early stages of the D2O Project.

OPG may have had the option of writing off expenses associated with scope changes and design elaboration. Instead, $0.6 million was written off in OM&A for OPG's assessment of the preliminary engineering and project management work that was no longer used.[157]

The OEB finds it appropriate to permanently disallow $94 million in rate base additions. In the context of the final D2O Project and the services it provides, the OEB ascribes $20 million in value to ratepayers up to the termination of B&M in October 2014 as an addition to rate base.

In permanently disallowing $94 million from rate base, the OEB has considered the cost of poor management and errors prior to B&M's termination. The OEB finds that the evidence associated with the costs incurred does not support a conclusion of prudence. Instead, the OEB finds that the evidence has brought forth a host of issues suggestive of mismanagement and imprudence on OPG's part, including:

1. **Project funding was prematurely approved** by OPG's executive management based on project cost estimates that were misrepresented in the AACE[158] classification system

[156] OPG Reply Submission / p. 27.
[157] Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2I / p. 4.
[158] AACE is the Association for the Advancement of Cost Engineering.

2. **EPC contract terms were not understood** by the P&M group tasked with managing B&M, the EPC contractor. As a result, the "hands-off" approach taken by P&M was not aligned to manage risks and incurred costs

3. **P&M group lacked adequate training and experience** to manage the D2O Project

4. **Risk management was inadequate** and did not follow OPG's standard procedures for DRP projects

5. **Inaccurate and insufficient reporting** to executive management delayed corrective action from being taken.

In support of these findings, the OEB has benefitted from independent third-party reports, filed as evidence, that provide insight into the above-noted conclusions. These reports commissioned by OPG are authored by Modus / Burns. Each OEB finding is supported by quotes from the Modus / Burns Quarter 2, 2014 Report to OPG's Board of Directors:

1. **Project funding was prematurely approved**
   - "[P&M] [m]ischaracterized the nature of these estimates by assuming anything provided by a contractor was at a very high level of maturity (Class 3/2) when such estimates were based on conceptual (at best) engineering, meaning these estimates could not have been better than Class 5 (-50% to +100%) in nature."[159]

2. **EPC contract terms were not understood**
   - "P&M believed 'the EPC Process' would mitigate known risks via 'project efficiency gains due to the expertise and autonomy of the contractor.'"[160]
   - "[P&M]… incorrectly applied an 'oversight' project management approach for its EPC contracting strategy, leading to a series of cascading management failures and contractor performance issues…"[161]
   - "P&M's error was misunderstanding the essential nature of the ESMSA contracts, which are not fixed-price EPC contracts that shift all risk and responsibility for performance to the contractors…"[162]

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159 Exhibit L / D2-02-Staff-105 / Attachment 2 / p. 180.
160 *Ibid.*
161 *Ibid.* / p. 176.
162 *Ibid.* / p. 180.

- "The fact that the contract is cost-reimbursable, require the owner to engage in active management of the contractors and coordinate interfaces. This means providing very specific instructions to lock down scope at the project's conceptual design phase and holding the contractors accountable on a daily basis to meet expected cost and schedule."[163]

3. **P&M group lacked adequate training and experience**
   - "P&M was completely overwhelmed in trying to manage… the D2O [Project]"[164]
   - "It is apparent that the P&M Team did not have the necessary experience, training or internal management direction to properly manage this work."[165]

4. **Risk Management was inadequate**
   - "Risk management training is virtually non-existent in the P&M organization…"[166]
   - "There is no structured or defined risk program management oversight (such as the Nuclear Refurbishment Risk Oversight Committee)"[167]
   - "P&M does not actively manage its on-going risks as a part of an effective risk management program"[168]
   - "This suggests a lack of understanding of the value of a risk management program or lack of acceptance, which can be addressed by effective training and indoctrination"[169]
   - "It appears that all P&M's identification of risks is a 'check-the-box' activity due the fact that having a list of risks is a prerequisite to obtaining a funding release."[170]

5. **Inaccurate and insufficient reporting**
   - "P&M failed to update its project reports during the design phase to reflect cost increases due to scope changes in the projects"[171]
   - "The P&M team provided sporadic updates to the design milestones as they continued to be missed but failed to convey the potential consequence"[172]

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163 *Ibid.*
164 *Ibid.* / p. 176.
165 *Ibid.* / p. 180.
166 *Ibid.* / p. 182.
167 *Ibid.*
168 *Ibid.*
169 *Ibid.*
170 *Ibid.*
171 *Ibid.* / p. 183.
172 *Ibid.*

- "P&M's first reporting to senior management and other OPG stakeholders of any impact of the design changes that had been brewing for nearly two years was inconsistent at best"[173]
- "As a direct consequence of P&M's failure to report these cost and schedule variances, senior management was deprived of the ability to… mitigate the impact of the schedule delays and cost overruns".[174]

The subsequent 2018 Auditor General's Report focused on OPG's planning and execution of the DRP, including the prerequisite D2O Project, and echoed many of the Modus / Burns observations, including:

- misclassification of contractors' estimates
- assigning prerequisite work to staff with limited relevant experience with complex project work
- poor project management of external contractors due to its "hands-off" project management approach
- lack of detailed planning and understanding of project work complexity
- poor risk assessment
- did not challenge or put enough pressure on the contractors to meet the Project's cost and time estimates.[175]

The OEB notes that OPG relied upon an independent expert report prepared by Bates White as evidence to support that $510 million was the true cost of the D2O Project.

With respect to the Bates White Report, the OEB finds that this report offers little substantive or probative value in assisting the OEB in determining whether OPG's actual costs for the D2O Project were prudent. The OEB is of the view that the Bates White Report was an ineffectual statistical and tautological exercise to prove a known fact: that OPG spent $510 million to build what was the final design and scope of the D2O Project. Stated differently, the Bates White Report is based on a model that is better characterized as a self-fulfilling prophecy. The model used assumptions and actual known costs incurred by OPG as inputs to derive a range of cost outputs with a most probable project cost estimate of just over $510 million. Because the authors had access to all the cost information provided by OPG, the OEB cannot regard the report as an independent analysis of the true costs of the D2O Project.

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[173] *Ibid.* / p. 184.
[174] *Ibid.* / p. 185.
[175] Exhibit K1.9 / pp. 150-156.

OPG submitted that the OEB should rely on the oral testimony of Bates White "…[w]e honestly did not let that colour our expectations as to where the number would come out."[176] The OEB finds that the Bates White Report did not meet expectations of independence because the final cost was known upfront. It did not provide independent evidence and needed considerable assistance from OPG in carrying out its analysis.

This lack of independence could have been avoided. OEB staff and intervenors drew comparisons to High Bridge Associates, Inc.'s (High Bridge) approach to independence during the D2O Recovery Plan. To ensure independence, High Bridge avoided reviewing CanAtom's estimate of the cost to complete. While the circumstances were slightly different, OPG chose to provide Bates White with cost estimates for the D2O Project – which Bates White accepted.[177] In addition, Bates White made errors in its calculations which had to be corrected at the oral hearing, and applied questionable input assumptions such as the inclusion of a 10% contingency in a perfect knowledge estimate.

In summary, the Bates White Report does not alter the OEB's assessment that the $114 million expended by OPG prior to B&M's termination was excessive and not representative of the accomplishment of project tasks required to justify that amount. The OEB's reduction of that sum to $20 million provides a reasonable recognition of the work done to that date for the purpose of its inclusion in rate base.

<u>Disallow Carrying Costs for the In-service Delay from May 2017 to March 2020</u>

An examination of the project execution and costs incurred following the termination of the B&M contract discloses that the adverse effects of the initial unsuccessful attempt to achieve a satisfactory completion of the D2O Project extended to the work done subsequent to October 2014. In addition, there were problems associated with the relationship between the new contractor, CanAtom, and OPG that led to delays. These delays appear far from what could be considered reasonable given the expected knowledge of OPG at that stage of the project's execution, especially given OPG's experience with B&M and the commentary included in the Modus / Burns reports.

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[176] OPG Reply Submission / p. 95.
[177] Oral Hearing Transcripts / Vol. 3 / p. 118. The OEB notes that Bates White stated that "[a]nd not having asked to be shielded from some things, perhaps with 20/20 hindsight we could have proceeded differently on that front."

In October 2014, OPG terminated its EPC contract with B&M and became the general contractor. In December 2014, OPG issued a competitive work request to CanAtom and ES Fox. In early 2015, CanAtom became the successful proponent.[178]

In March 2015, the 2015 Superseding Execution Release ($381.1 million) was approved. Prior to this release, OPG's estimate to complete the project had been informed by its own project management experience including ongoing project costs and performance to date including the following:

1. A scope review conducted in April 2014 by OPG, B&M and its subcontractors to improve the schedule and control costs[179]
2. The development of a firm estimate by OPG and B&M assisted by Faith and Gould (an earlier consultant on project costs)[180]
3. Receipt of the responses to the competitive work requests from ES Fox and CanAtom.

The $381.1 million approved budget provided for an increase in costs of $271 million from the 2013 Full Execution Release ($110 million). The increase in costs was primarily attributed to the following:

- Change to a stand-alone building rather than a three-sided building attached to the TRF
- Increased materials quantities for piping, valves and equipment due to design changes and the need to install stand-alone systems rather than tying into existing systems at the TRF
- Increased construction costs due to changes from the preliminary to the final design
- Required installation of the pipe chase given the reconfiguration of the building and to address water-hammer issues in the preliminary design
- Need to address tritiated soil and water
- Underestimation of effort by the original contractor.[181]

The approved budget of $381.1 million included a contingency of $33.9 million. The $381.1 million estimate was classified by OPG as an AACE Class 2 estimate. Class 2

[178] Exhibit D2 / Tab 2 / Schedule 10 / Attachment 4.
[179] Exhibit D2 / Tab 2 / Schedule 10 / p. 67.
[180] *Ibid.* / p. 66.
[181] *Ibid.* / p. 110.

engineering estimates range between -15% to +20%, so the final cost of the D2O Project should have ranged between $323.9 million and $457.3 million.

The October 2015 in-service date set out in the 2013 Full Execution Release was changed to May 2017 in the 2015 Superseding Execution Release.

In light of OPG's knowledge gained through its experience with B&M and all the lessons learned from the early years of the project, it is reasonable to expect that the May 2017 in-service date would have been met. It was the date that OPG's President and CEO, CFO and Senior Vice President of Nuclear Projects approved in the 2015 Superseding Execution Release.

Yet in February 2018, OPG issued another Superseding Execution Release ($510 million) that approved an additional $117.4 million and included a management reserve of $11.5 million bringing the total amount authorized to $510 million. In its evidence, OPG set out the reasons for the further escalation of project costs:

> As with the 2015 Superseding Release Execution BCS, the 2018 Superseding Release Execution BCS analyzes the variances that led to increased project costs. Several of the factors identified above as most significantly contributing to the increase in project cost, including increased project scope and underestimation of cost, continued to be major factors in the increased cost of the EPC contract, which makes up the bulk of the cost increase approved in this BCS. The other major factors identified in the 2018 Superseding Release Execution BCS as increasing project cost are:
>
> - Increased interest costs due to a deferred in-service date
> - Increased OPG project management costs due to the schedule extension and the transition to a new contract
> - Increased cost for OPG engineering due to the schedule extension
> - During the transition, OPG determined that certain manuals and procedures should be developed and documented by the TRF.
> - Costs that OPG incurred when it acted as the general contractor for the project.[182]

The OEB's review of OPG's reasons for incurring additional costs discloses that problems and delays caused by the project history with B&M continued to hamper and adversely impact the D2O Project. These reasons include:

[182] *Ibid.* / pp. 111-112.

- It was necessary for OPG to assume general contractor duties in October 2014 after B&M was terminated and until CanAtom assumed control of the project site in January 2016

- There was a time-consuming process of securing a new contractor including the competition work request, initial negotiations and execution of a Limited Notice to Proceed with CanAtom

- There was a redesign of the seismic dike slab and building superstructure necessitated by the questionable initial design endorsed by RCM Technologies Canada Corporation and B&M.[183]

In addition, OPG had a turbulent relationship with CanAtom epitomized by OPG's inability to manage its contractor. More specifically:

- Commercial disputes commenced with a Project Change Notice by CanAtom, demanding an increased contract price caused by the redesign

- In 2017, there were multiple disputes with CanAtom that escalated to a slowdown and stop work demand until an agreement on a Maximum Price Guarantee was obtained

- Delays and failures of performance by CanAtom that required close supervision of work arrangements

- Further agreement between OPG and CanAtom was needed to resolve issues in February 2018.[184]

The total cost for completion of the D2O Project requested by OPG is $510 million. The evidence indicates that CanAtom settled its commercial disputes with OPG concerning terms and performance cost. This settlement resulted in unrecovered costs for CanAtom of $77 million. The 2015 Superseding Execution Release was presumably made with the benefit of lessons learned and the experience that OPG gained throughout the project to that date. Despite the benefit of that experience, the final cost to OPG of $510 million exceeds the upper bound of the Class 2 estimate of $457.3

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[183] *Ibid.* / pp. 71, 78-82.
[184] *Ibid.* / pp. 90-99.

million by over 11%, and by 28% if CanAtom unrecovered costs are included in the total.

It is clear to the OEB that it is the ratepayer, not the shareholder, that is being asked to pay for all of OPG's incurred costs. In contrast OPG as the project owner has written off only $0.6 million (0.1%) as an unrecovered cost.[185] This differs from a settlement between CanAtom and OPG for work undertaken on or after June 27, 2017 which included a sharing arrangement known as "gain/pain sharing."[186] Conversely, OPG's proposal allocates 100% of OPG's share of the overspending pain to its ratepayers. The OEB does not find this reasonable.

In the face of escalating costs that OPG claims were not possible to foresee nor avoid and accompanying project completion delays, the OEB cannot find that OPG's project management has been consistently reasonable and prudent.

Previously in the Decision, the OEB disallowed capital costs related to project work done prior to the dismissal of B&M in October 2014.

Following that date, the OEB finds that the effects of the project delays were occasioned by OPG's failure to reasonably manage the completion of the work consistent with anticipated dates for the storage facility coming into service. This failure must be reflected in reductions to the total cost of the project to ratepayers. The principal impact of the delays is associated with the accrual of interest costs following that date, which added to the total cost of the D2O Project.

While the OEB accepts the design and construction costs incurred from October 2014 to completion, the OEB will not allow the recovery of any interest costs capitalized to the D2O Project between May 2017, which is the in-service date that was forecast in the 2015 Superseding Execution Release, and the date that the prudent cost is allowed into rate base. For clarity, the OEB finds that the prudent in-service capital cost of the D2O Project is $509.3 million less $94 million and less any accrued interest from May 2017 to March 2020.[187]

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[185] Oral Hearing Transcripts / Vol. 3 / p. 32.
[186] Exhibit D2 / Tab 2 / Schedule 10 / pp. 96-97.
[187] As noted previously, section 5.2 includes the OEB's determination that OPG's proposed partial in-service additions in 2016 and 2019 for the D2O Project are appropriately considered in-service in March 2020.

The OEB finds that the completed design and build of the final D2O facility was fit for purpose despite the inaccurate cost estimates and OPG's imprudent project management. While OPG's assessment of alternatives was not robust, alternatives were considered and included in all business case summaries. There is insufficient evidence that a different configuration or scope would have been a more prudent decision.

Allocation of D2O Project Costs (to Decommissioning)

AMPCO / CCC stated that once the DRP is complete, 1,500 m^3 of the storage capacity within the D2O Project may be used to support the decommissioning of Pickering. Specifically, the storage may be used to support some of the long-term storage requirements for the Pickering units. AMPCO / CCC submitted that it is important to flag the possible change of use in the current proceeding as there could be a related change in accounting for the costs associated with the storage capacity once the DRP is complete.

AMPCO / CCC stated that the decommissioning activities related to Pickering are contemplated and funded by the Nuclear Liabilities amounts that are already recovered in payment amounts. More specifically, funding for the long-term storage costs associated with heavy water from decommissioned units is a cost that is included in the scope of the Ontario Nuclear Funds Agreement (ONFA) as a decommissioning cost that is funded through the Decommissioning Fund. Accordingly, if any part of the storage in the D2O Project is used for decommissioning, the cost of that storage should either be recovered directly from the Decommissioning Fund as other revenue, or the costs of the storage removed from rate base.[188]

SEC submitted that the OEB should direct OPG, in its next payment amounts proceeding, to file a study or studies showing: (a) the likely use of the D2O Project for the long-term heavy water storage of decommissioned units; (b) the amounts currently set aside in the Decommissioning Fund for long-term heavy water storage; and (c) an integration of the two to show the extent to which the costs of the D2O Project should be allocated to decommissioning costs. With this information, the OEB can determine if some part of the remaining unamortized net cost of the D2O Project should be re-allocated to decommissioning cost. This will ensure that ratepayers do not pay for this storage twice – once in payment amounts and once in decommissioning costs.[189]

[188] AMPCO / CCC Submission / pp. 49-50.
[189] SEC Submission / p. 40.

LPMA supported AMPCO / CCC's submission with respect to the appropriate allocation of the D2O Project costs.[190]

In its reply argument, OPG noted that submissions suggesting costs of the D2O Project could be potentially recovered from the Decommissioning Fund are incorrect. OPG submitted that the D2O Project was built for two purposes only: refurbishment and the ongoing operational needs of Darlington, including those of the TRF. OPG submitted that the cost of the D2O Project is properly recorded as an operational asset in OPG's financial statements and appropriately forms the non-nuclear liability aspect of rate base for recovery through payment amounts. OPG confirmed in reply argument that the costs are not duplicated as no portion of the D2O Project cost is reflected in the ONFA Reference Plan cost estimates underpinning the current revenue requirement for nuclear liabilities.

OPG further stated that no decision has been made regarding the use of the D2O Project to store heavy water from Pickering decommissioning. In the event that the D2O Project is used to store heavy water from Pickering decommissioning, and nuclear liability costs decrease as a result, this would be reflected in a future ONFA Reference Plan cost estimate, with a corresponding adjustment to revenue requirement impacts. To the extent it was appropriate to attribute a portion of the D2O costs to nuclear liabilities (which OPG maintains it is not), such costs would be simply reallocated from non-nuclear liabilities to the nuclear liabilities' portion of the revenue requirement.[191]

Findings

The OEB accepts that OPG has made no decision on heavy water management related to Pickering decommissioning. In the interim, the OEB is satisfied there is no "double counting" of D2O Project costs in the proposed payment amounts for the 2022-2026 period at issue in the current proceeding.

Understanding the plan and estimated costs for heavy water storage management associated with the end of Pickering's commercial operations will be an issue in a future OEB proceeding. The OEB will not direct OPG to provide a study regarding the "likely use" of the D2O Project for the long-term heavy water storage of decommissioned units in its next payment amounts application. However, OPG should be prepared to explain its proposed heavy water management plan and provide the costs of heavy water

[190] LPMA Submission / pp. 5-6.
[191] OPG Reply Submission / pp. 106-109.

storage associated with decommissioned units as embedded in its ONFA estimates at that time, compared to other available options.

5.2 D2O Project-related Capacity Refurbishment Variance Account Balance

OPG noted that the revenue requirement impacts of the D2O Project have been recorded in the CRVA as the related assets have been placed in-service. These revenue requirement impacts will continue to be recorded in the CRVA until the effective date of nuclear payment amounts that reflect the D2O Project's inclusion in rate base. OPG requested approval to clear the December 31, 2019 CRVA debit balance of $58.1 million related to the D2O Project, which is largely related to a proposed 2016 in-service amount of $160 million, and a proposed 2019 in-service amount of $320.9 million.[192]

AMPCO / CCC, LPMA, SEC and OEB staff submitted that the OEB should reject the proposed 2016 and 2019 in-service dates and defer the in-service date to 2020 when the D2O Project was capable of receiving heavy water.[193]

AMPCO / CCC noted that the $160 million in-service addition in 2016 reflects completion of the seismic dike and installation of piping to connect five PHT tanks. However, the D2O Project was not used to store heavy water for Unit 2 in 2016. Instead, the existing Heavy Water Management Building was used to temporarily store Unit 2 heavy water. To make the necessary storage space available, heavy water was transferred to Pickering and Bruce. AMPCO / CCC argued that the D2O Project was not used or useful in 2016 as it would have required installation of several temporary safety systems, such as leak detection and radiation monitoring, to safely store radioactive heavy water in the building, which would have added to the D2O Project's cost.

AMPCO / CCC stated that the D2O Project was declared capable of accepting heavy water in March 2020, and in November 2020 the D2O facility accepted heavy water for the first time when heavy water was drained from Unit 3. Thus, the appropriate year to include in-service capital amounts in rate base is 2020 as the facility was neither used nor useful prior to 2020.[194] OEB staff, SEC and LPMA made similar arguments, yet

[192] OPG Argument-in-Chief / p. 33; and Exhibit D2 / Tab 2 / Schedule 10 / p. 12.
[193] OEB Staff Submission on Unsettled Issues / p. 20; AMPCO / CCC Submission / p. 49; LPMA Submission / p. 6; and SEC Submission / p. 38.
[194] AMPCO / CCC Submission / pp. 48-49.

OEB staff was specific, arguing that the in-service month for the D2O Project should be March 2020.[195]

In its reply argument, OPG submitted that the OEB should accept its 2016 and 2019 in-service additions because the relevant elements of the D2O Project became useful at those times. OPG stated that it follows a comprehensive process to deem assets used or useful prior to declaring them in-service. OPG stated that approval for placing assets in-service is captured in Report of Equipment In-Service (REIS) documentation which is in evidence in this proceeding.

OPG stated that the 2016 in-service addition represented the costs of the seismic dike, five PHT storage tanks, valves, and the pumps and piping necessary to allow them to receive heavy water if required. All inspection and quality documents related to this work were signed off by both civil contractors, and completion assurance was completed by OPG. Although these assets were considered useful at the time, OPG decided not to use the unfinished building as temporary storage during the Unit 2 refurbishment. OPG stated that to use the unfinished building, temporary support systems would have been required to safely store heavy water which would have altered its construction plan. OPG submitted that while the assets were not ultimately used, they are appropriately considered useful in providing an alternative option to store Unit 2 heavy water.

OPG stated that the 2019 in-service addition represented the costs of the process systems, process support systems and building support systems necessary to enable functionality of the facility. Almost all of the systems, equipment, seismic dike and above ground portions of the building had been placed into service and the project was substantially complete for its intended use by November 2019 and was available to store Unit 3 PHT and moderator water, if needed. However, the DRP schedule at the time forecast that the facility would not be needed to store Unit 3 heavy water until April 2020. Therefore, additional life safety systems required to enable occupation of the building were completed between November 2019 and March 2020. OPG submitted that the 2019 in-service additions were useful, and some were actually used in November 2019.

OPG also submitted that had it placed the $160 million and $320.9 million in-service in March 2020, instead of 2016 and 2019, the D2O Project would have accrued approximately $30 million in additional financing costs that would have been capitalized

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[195] OEB Staff Submission on Unsettled Issues / p. 20.

on the construction-work-in-progress balance. Together with recalculated depreciation amounts based on a later in-service date, this would increase the 2022-2026 revenue requirements by a total of approximately $17 million, decrease the tax loss carried forward beyond 2026 by approximately $13 million, and similarly increase the revenue requirements from 2027 until the end of asset life. Over time, higher total project costs would more than offset a lower proposed balance in the CRVA resulting from the application of a March 2020 in-service date.

Overall, OPG submitted that declaring D2O Project assets in-service in 2016 and 2019 as they became used or useful was appropriate, and benefits ratepayers as a result of reduced total project costs.[196]

Findings

The OEB must decide the applicable date for recognizing the approved D2O Project capital costs in rate base. The traditional approach has been to consider utility assets as rate base when those assets are "used and useful."[197] This approach has been often modified, in part, by statutory provisions in governing legislation or by regulatory practice recognizing utility exigencies in delivering service. Such modifications have taken the form of adoption of a test of "used or useful" for consideration of the status of utility assets.[198]

In Ontario, the previous *Ontario Energy Board Act* provided rate base was "…property that was used or useful in serving the public…"[199] The Act was subsequently changed and the provision set out in the above section was eliminated. Henceforth determinations concerning rate base for natural gas were to be made in accordance with provisions in the OEB Act that required the OEB to approve "just and reasonable rates" determined in accordance with "any method or technique that it considers appropriate" for the regulation of natural gas distribution transmission and storage.[200] Determinations based on just and reasonable rates are also required for electricity transmission and distribution[201] and for the determination of just and reasonable payments to generators.[202] Neither of the provisions in the OEB Act for electricity or generation contain specific requirements for the determination or treatment of rate base.

[196] OPG Reply Submission / pp. 109-113.
[197] *Smyth v. Ames*, 171 U.S. 361 (1898), *Calgary Power v. Camrose (City)*, [1975] 2 SCR 465.
[198] *Ontario (Energy Board) v. Ontario Power Generation*, 2015 SCC 44, paras. 90-91.
[199] *Ontario Energy Board Act*, R.S.O. 1980, c. 332, sec. 19(3).
[200] OEB Act, sec. 36(2) and (3).
[201] *Ibid.*, sec. 78(3).
[202] *Ibid.*, sec. 78.1(5).

Since the passage of the 1998 OEB Act, both the traditional[203] and modified[204] versions of the formulation of the test have been referenced in the determination of a number of OEB decisions as well as in a Divisional Court appeal.

A central tenet of both articulations of eligibility for inclusion in rate base is that the asset in question must be available for use or be fit or available for use to provide service to utility customers.[205] The determination of the usefulness and ability to service utility needs is an essential requirement for an asset being included or remaining in rate base.[206]

In the Decision, the OEB finds that the D2O Project will provide a service that is essential for the operation of OPG's nuclear fleet. However, the OEB is not persuaded by OPG's argument that these assets were useful prior to March 2020. OPG stated that the unfinished building would have required temporary support systems at an additional cost to safely store heavy water.[207]

In 2016, the building's inability to fulfill its operational objectives to store Unit 2 heavy water is a relevant fact that proves that the D2O Project was not operational. The Darlington nuclear facility has four units; therefore, by not serving Unit 2 during refurbishment, the D2O Project did not meet 25% of the DRP objectives. Instead, the existing Heavy Water Management Building was used to temporarily store Unit 2 heavy water, and to make the necessary storage space available, heavy water was transferred to Pickering and Bruce.

In 2019, the D2O Project was still not able to safely store heavy water, thereby not fulfilling its operational objectives, until the life safety systems, required to allow human

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[203] For example, "used and useful" has been adopted by the OEB in OPG's 2017-2021 Payment Amounts proceeding (EB-2016-0152), December 28, 2017, London Hydro Inc. (EB-2008-0235), August 21, 2009, Newmarket-Tay Power Distribution Ltd. (EB-2020-0041), April 22, 2021, and by the Divisional Court in *Toronto Hydro-Electric System Limited,* [2009] O.J. No. 1872. (affirming EB-2007-0680).
[204] "Used or useful" has been adopted in PowerStream Inc. (EB-2008-0244), July 27, 2009, Toronto Hydro-Electric Systems Limited (EB-2012-0064), April 2, 2013, and Toronto Hydro-Electric System Limited (EB-2014-0116), December 29, 2015.
[205] In PUC Distribution Inc. (EB-2020-0249/EB-2018-0219), April 29, 2021, the OEB found that "[t]he OEB also requires PUC Distribution to establish the generic ICM sub-accounts. Per the ICM policy, these sub-accounts are subject to the assets being **used** or **useful** (i.e. in-service). If the assets for the Project are not in-service in 2022, they are treated as construction work in progress." (Emphasis added.)
[206] Assets that are no longer required to meet a utility service need cannot be included as regulatory assets and considered part of rate base. *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2004 ABCA 3 affirmed on appeal *ATCO Gas & Pipelines Ltd. v. Alberta (Energy and Utilities Board),* 2006 SCC 4; see also *ATCO Gas South, Re*, 2008 ABCA 200.
[207] OPG Reply Submission / p. 111.

occupation of the building, were installed. In its reply submission, OPG claimed that the D2O facility was "actually used in 2019."[208] However, the OEB finds that OPG has not substantiated that claim. If an asset's use is to provide additional or standby capacity, the ability to provide that use is critical. In November 2019, this was not the case.

Regarding OPG's entries into its internal REIS in 2016 and 2019, the OEB does not find that such entries are binding on the OEB in the determination of what amount should be placed in rate base. The OEB has considered OPG's terminology of "substantial completion" as of November 2019 and "facility declared capable of accepting heavy water" as of March 2020[209] and finds that the ability to have the asset available for use is the primary consideration of when to include the cost of those assets in rate base.

For the reasons set out above, the OEB denies the proposed 2016 and 2019 in-service additions and finds that March 2020 is the appropriate in-service date of the approved costs for inclusion in rate base.

OPG is directed to provide a detailed calculation of the impact of the OEB's findings regarding the D2O Project permanent rate base disallowance comprised of $94 million and the carrying costs incurred from May 2017 to March 2020, and the approved change to a March 2020 in-service date, on both the CRVA balance and rate base in its draft payment amounts order.

[208] *Ibid.* / p. 112.
[209] Exhibit D2 / Tab 2 / Schedule 10 / Attachment 4 / p. 8.

6 IMPLEMENTATION

In the approved settlement proposal, the parties agreed that the effective date for new payment amounts and riders will be January 1, 2022.[210]

The approved settlement proposal includes an agreement to defer the consideration of rate smoothing to the payment amounts order stage of the proceeding.[211]

The OEB directs OPG to file a draft payment amounts order that reflects the OEB's findings in the Decision and the 2022 ROE rate of 8.66% approved by the OEB on October 28, 2021[212] in accordance with the approved settlement proposal.[213] The draft payment amounts order shall also include rate smoothing alternatives. The OEB will provide intervenors and OEB staff the opportunity to provide comments on the draft payment amounts order (including the rate smoothing alternatives) and OPG the opportunity to respond to any comments received.

With respect to rate smoothing, the OEB would like to see a range of alternatives to consider the impact on the rate smoothing guiding principles as approved in the decision in OPG's 2017-2021 Payment Amounts proceeding.[214] The OEB requires OPG to file the following in a comparison chart similar to Chart 3, "Smoothing Alternatives – Outcomes" filed in evidence.[215] The new chart shall include a row with the amount of revenue requirement deferred during the 2022-2026 period associated with each alternative. The new chart shall include the following alternatives (at a minimum):

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

[210] Settlement Proposal / p. 50.
[211] *Ibid.*
[212] OEB 2022 Cost of Capital Parameter Update Letter, October 28, 2021.
[213] Settlement Proposal / p. 24. The parties agreed 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.
[214] EB-2016-0152 / Decision and Order / December 28, 2017 / p. 155.
[215] Exhibit I1 / Tab 3 / Schedule 2 / p. 8.

- A ranking of the "best" credit metrics alternative, from OPG's perspective.[216]

The OEB will set out the cost claim process for those intervenors that were granted cost eligibility in its final payment amounts order for this proceeding.

[216] The OEB asks OPG to identify the "best" credit metrics alternative, from OPG's perspective, such that the OEB may consider this in addition to: (a) the lowest cash flow from operations pre working capital to debt ratio (2022-2026); and (b) lowest funds from operations to debt ratio (2022-2026).

7 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The settlement proposal, which was approved at the conclusion of the oral hearing on August 6, 2021, is attached as Schedule A.

2. OPG shall file with the OEB, with a copy to intervenors, a draft payment amounts order that reflects the OEB's findings in the Decision, the 2022 ROE rate as specified by the OEB in its cost of capital report, and OPG's rate smoothing proposal (including alternatives to its proposal) no later than **November 29, 2021**.

3. OEB staff and intervenors shall file with the OEB, with a copy to OPG, any comments on the draft payment amounts order (including the rate smoothing proposal) no later than **December 6, 2021**.

4. OPG shall file with the OEB, with a copy to intervenors, a response to any comments no later than **December 13, 2021**.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, **EB-2020-0290** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the Filing Systems page on the OEB's website
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance

All communications should be directed to the attention of the Registrar at the address below and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Managers, Lawrie Gluck at Lawrie.Gluck@oeb.ca and Shuo Zhang at Shuo.Zhang@oeb.ca, and OEB Counsel, Michael Millar at Michael.Millar@oeb.ca and Ian Richler at Ian.Richler@oeb.ca.

Email: registrar@oeb.ca
Tel: 1-877-632-2727 (Toll free)

DATED at Toronto November 15, 2021

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

SCHEDULE A

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

APPROVED SETTLEMENT PROPOSAL

EB-2020-0290

NOVEMBER 15, 2021

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

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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)