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

BY E-MAIL

March 11, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ritchie Murray:

Re: Ontario Power Generation Inc. and DNNP LP (the Applicants)
2027-2031 Payment Amounts
Ontario Energy Board (OEB) File Number: EB-2025-0297

In accordance with Procedural Order No. 2, please find attached the Ontario Energy Board (OEB) staff interrogatories in the above proceeding. The applicants and intervenors have been copied on this filing.

Procedural Order No. 2 also made provision for OEB staff to file additional interrogatories on March 25, 2026. As noted on March 6, 2026, OEB staff has recently retained several external experts to assist in this proceeding. OEB staff will limit the interrogatories filed on March 25, 2025 to those that will be prepared by or in co-ordination with those external experts. Further to OEB staff's letter to the Applicants dated March 2, 2026, OEB staff reiterates its request that the Applicants send their experts' working papers as soon as possible. This would facilitate OEB staff's experts' review of the evidence.

Any questions relating to this letter should be directed to the Case Managers, Thomas Eminowicz, at Thomas.Eminowicz@oeb.ca and Jeffrey Sauer, at Jeffrey.Sauer@oeb.ca. The OEB's toll-free number is 1-888-632-6273.

Yours truly,

Thomas Eminowicz
Digitally signed by Thomas Eminowicz
Date: 2026.03.11 15:50:24 -04'00'

Thomas Eminowicz
Senior Advisor,
Generation & Transmission

Jeffrey Sauer
2026.03.11 15:28:20 -04'00'

Jeffrey Sauer
Senior Advisor,
Generation & Transmission

OEB Staff Interrogatories
2027-2031 Payment Amounts Application
Ontario Power Generation (OPG) and DNNP LP
EB-2025-0297
March 11, 2026

Please note, the Applicants are responsible for ensuring that all documents they file with the OEB, including responses to OEB staff interrogatories and any other supporting documentation, 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*.

EXHIBIT A – ADMINISTRATIVE DOCUMENTS

A1-Staff-1

Ref 1: <u>OPG Letter, February 27, 2026 Re: Requirements of Ontario Regulation 53/05 ("O. Reg. 53/05"), Section 8</u>

Preamble:

In Reference 1, the applicants state:

> "Further to the EB-2025-0297 requested approval set out at Ex. A1-2-2, p. 10, DNNP GP Inc., as managing general partner on behalf of DNNP LP (the "DNNP generator"), requests that the Ontario Energy Board issue an order pursuant to section 8 of O. Reg. 53/05 for purposes of section 78.1 of the Ontario Energy Board Act, 1998 (the "Act") declaring that the DNNP generator has satisfied the conditions set out under section 8 of O. Reg. 53/05."

Question(s):

a) Please confirm that the Applicants do not require an order from the OEB regarding the section 8 criteria prior to the OEB's decision in this proceeding.

A1-Staff-2

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2
Ref 3: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3

Ref 4: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Ref 5: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4

Preamble:

References 1-5 are expert reports filed with the Applicants' pre-filed evidence.

References 1, 2, and 3 are reports filed by London Economics International, LLC, relating to Inflation Factor options, Total Factor Productivity benchmarking, and hydroelectric cost benchmarking.

Reference 4 is the common equity ratio study from Concentric Energy Advisors.

Reference 5 is the ScottMadden study of factors impacting total generation cost with normalizing adjustments relating to OPG Nuclear.

Question(s):

a) Please provide all underlying work files (including underlying database files, spreadsheets, program code, or other underlying documentation) used to produce the tables, figures, and calculations presented in each of the reports referred to above.

A1-Staff-3

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9-11

Preamble:

For the years 2028-2031, OPG proposes that its hydroelectric payment amount be adjusted annually according to a mechanistic custom price-cap adjustment, using a formula that includes an Inflation Factor.

OPG suggested that to calculate its proposed Inflation Factor, OPG uses the same sub-indices from Statistics Canada that the OEB uses when determining the inflation factor for electricity distributors and electricity transmitters, as follows:

- Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand (GDP IPI FDD)
- Average Weekly Earnings for Ontario – Industrial Aggregate (Ontario AWE)

However, in the current proceeding, OPG is requesting OPG-specific weightings to its proposed Inflation Factor. In "Chart 3 – Summary of Hydroelectric I-Factor Weighting", OPG is proposing a non-labour weight of 84.7% and a labour weight of 15.3%.

OEB staff has prepared the following "Table 1 – Summary of Inflation Factor Weightings", which summarizes the OEB's policy for electricity distributors and transmitters, as well as OPG's proposal.

Table 1 – Summary of Inflation Factor Weightings

	OEB Policy – Weightings Electricity Distributors	**OEB Policy – Weightings Electricity Transmitters**	**OPG Proposed Weightings**
Non-Labour	70%	86%	84.7%
Labour	30%	14%	15.3%
Total	100%	100%	100%

Question(s):

a) Please confirm that "Table 1 – Summary of Inflation Factor Weightings" is accurate. Please update the table as applicable and explain any changes made.

A1-Staff-4

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 10 & 11
Ref 2: OEB Letter, 2026 Inflation Parameters, June 11, 2025
Ref 3: EB-2021-0212, OEB 2022 IPI Generic Proceeding, Procedural Order No. 1, Fact Sheet, August 27, 2021

Preamble:

In the tables below, OEB staff has calculated the 2027 Inflation Factors using the weighting for electricity distribution, transmission, and as proposed by OPG.

OEB staff has relied on the following data from Statistics Canada which the OEB uses to calculate the Inflation Factors for electricity distribution and transmission:

- GDP-IPI (FDD): Statistics Canada, Table 36-10-0106-01 (formerly CANSIM 380-0066) - Price Indexes, gross domestic product, quarterly (2017 = 100 unless otherwise noted) - 2025 Q4, data accessed March 3, 2026
- Average Weekly Earnings (AWE): Statistics Canada, Table 14-10-0204-01 (formerly CANSIM 281-0027), Ontario, Industrial aggregate excluding unclassified businesses, annual (current dollars), data accessed March 3, 2026

OEB staff notes that the AWE represents annual data and will be updated in late March 2026 by Statistics Canada.

OEB staff observes that the OEB typically uses the logarithmic growth rate in its calculations, as noted in the OEB Letter, 2026 Inflation Parameters, June 11, 2025, Appendix. As set out in the EB-2021-0212, OEB 2022 IPI Generic Proceeding, Procedural Order No. 1, Fact Sheet, August 27, 2021, the calculations of the “Annual % Change”… are based on the logarithmic growth rate, as opposed to the arithmetic growth rate.

Table 1 – Distribution - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

		Inputs and Assumptions										
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	70%	1,293.52	4.9%	30%	3.4%

Table 2 – Transmission - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

		Inputs and Assumptions										
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	86%	1,293.52	4.9%	14%	3.1%

Table 3 – OPG - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

		Inputs and Assumptions										
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees -			Resultant Values - the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	84.7%	1,293.52	4.9%	15.3%	3.1%

Question(s):

a) Please confirm that the following tables are accurate. Please update the tables as applicable and explain any changes made.
   - Table 1 - Distribution - Inflation Factor for 2027 Rate Year
   - Table 2 - Transmission - Inflation Factor for 2027 Rate Year
   - Table 3 - OPG - Inflation Factor for 2027 Rate Year

b) Please update the above-noted tables (or any revised tables) with the AWE data that will be updated in late March 2026 by Statistics Canada.

A1-Staff-5

Ref 1: EB-2016-0152, Decision and Order, December 28, 2017, p. 122
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / pp. 1, 10 & 11
Ref 3: Exhibit I1 / Tab 1 / Schedule 1 / Table 1
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 / p. 36

Preamble:

In OPG's payments amounts for 2017-2021, the OEB approved weights of 88% non-labour and 12% labour for OPG. The OEB did not approve a rate-setting framework for the prescribed hydroelectric facilities in the EB-2020-0290 proceeding, as the payment amounts for those facilities were legislatively frozen under O. Reg. 53/05, s. 6(2)13.

OEB staff notes that the impact of OPG's proposal to use OPG-specific weightings for non-labour and labour have both an immaterial impact and zero impact. This is as compared with the OEB's standard weights for electricity distributors and electricity transmitters, respectively, on OPG's proposed 2027 Revenue Requirement for Regulated Hydroelectric. Please see OEB staff's tables below that calculate the immaterial and zero impacts.

OPG noted that its materiality threshold is $20 million.

Table 1– Calculation of Immaterial Impacts using OPG-Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year

OEB staff calculated Inflation Factor Using OPG-Specific Weights	3.1%
Less: OEB staff calculated Inflation Factor Using Dx-Specific Weights	3.4%
Difference - Equals an approximate net impact of 0.3% on OPG's revenue requirement	-0.3%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1 / Schedule 1 / Table 1	$1,630,407,512
Approximate net impact of 0.3% on OPG's revenue requirement	($4,891,223)
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$20,000,000

Table 2 – Calculation of Zero Impacts using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year

OEB staff calculated Inflation Factor Using OPG-Specific Weights	3.1%
Less: OEB staff calculated Inflation Factor Using Tx-Specific Weights	3.1%
Difference - Equals an approximate net impact of 0.0% on OPG's revenue requirement	0.0%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1 / Schedule 1 / Table 1	$1,630,407,512
Approximate net impact of 0.0% on OPG's revenue requirement	$0
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$20,000,000

Question(s):

a) Please confirm that the following tables are accurate. Please update the tables as applicable and explain any changes made.
   - Table 1 – Calculation of Immaterial Impacts using OPG-Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year
   - Table 2 – Calculation of Zero Impacts using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year

b) Please update the above-noted tables (or any revised tables) with the Average Weekly Earnings (AWE) data that will be updated in late March 2026 by Statistics Canada.

c) Please elaborate whether OPG agrees or disagrees with OEB staff's demonstration that the impact of OPG's proposal to use OPG-specific weightings has both an immaterial impact and zero impact on OPG's 2027 revenue requirement for hydroelectric, when compared to electricity distributors and transmitters, respectively.

d) Please provide an OEB precedent (including EB#) where the OEB approved different weightings for the Inflation Factor calculations, other than the generic weights approved by the OEB for electricity distribution and transmission, and the OPG EB-2016-0152 Decision and Order.

A1-Staff-6

Ref 1: Exhibit A1 / Tab 4 / Schedule 4

Preamble:

At Reference 1, it is stated that DNNP LP is expected to be the OEB-licence holder for the Darlington New Nuclear Program (DNNP) facilities.

Question(s):

a) Please outline and describe the Applicants' plan for an OEB Generation Licence for the Darlington New Nuclear Program facilities.

A1-Staff-7

Ref 1: Exhibit A1 / Tab 4 / Schedule 2 / Chart 1
Ref 2: EB-2013-0321, Exhibit A1 / Tab 4 / Schedule 2

Preamble:

At Reference 1, OPG lists the prescribed hydroelectric generating stations with, among other things, the net in-service installed capacity for each. Reference 2 provides the same type of information at the time of the EB-2013-0321 proceeding.

Question(s):

a) Please confirm the following table correctly compiles the information from References 1 and 2. Please correct any data errors. Please add data to the final column to identify the expected net in-service installed capacity for each prescribed hydroelectric generating station by the end of 2031:

Table 1 – List of Prescribed Hydroelectric Generating Stations with In-Service Capacity (MW)

Region	Generating Station	In-Service Capacity EB-2013-0321 (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
Eastern	Abitibi Canyon	349	344.8	
	Arnprior	82	81.6	
	Barrett Chute	176	176.1	
	Bingham Chute	1	1	
	Calabogie	5	10.7	
	Chats Falls	96	96	
	Chenaux	144	143.7	
	Chute	3	2.9	
	Coniston	5	2.7	
	Crystal Falls	8	8.4	
	Des Joachims	429	428.8	
	Elliott Chute	2	1.6	
	Lower Notch	274	274.2	
	Matabitchuan	10	9.6	
	McVittie	3	2.8	
	Mountain Chute	170	170.2	
	Nipissing	2	0	
	Otter Rapids	182	182.4	
	Otto Holden	243	242.8	
	R.H. Saunders	1045	1045	
	Stewartville	182	182.1	
	Stinson		5.4	
Western	Aguasabon	51	47.1	
	Alexander	69	68.9	
	Auburn	2	1.9	
	Big Chute	10	10	
	Big Eddy	8	8	
	Cameron Falls	92	91.6	
	Caribou Falls	91	91.3	
	Eugenia	6	6.1	
	Frankford	3	2.6	

Region	Generating Station	In-Service Capacity EB-2013-0321 (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
	Hagues Reach	4	3.6	
	Hanna Chute	1	1.4	
	High Falls	3	2.7	
	Kakabeka Falls	25	24.6	
	Lakefield	2	1.8	
	Manitou Falls	73	73.1	
	Merrickville	2	1.7	
	Meyersburg	5	5.2	
	Pine Portage	142	145.9	
	Ragged Rapids	8	8.3	
	Ranney Falls	10	19.5	
	Seymour	6	5.7	
	Sidney	4	4.4	
	Sills Island	2	1.8	
	Silver Falls	48	52.4	
	South Falls	4	5.9	
	Trethewey Falls	1.7	1.8	
	Whitedog Falls	69	67.8	
Niagara	DeCew Falls 1	23	22.8	
	DeCew Falls 2	144	144	
	Sir Adam Beck 1	427	557.9	
	Sir Adam Beck 2	1499	1499.2	
	Sir Adam Beck PGS	174	174	

b) Please list all the generating stations from part a) that have had a realized efficiency gain from the EB-2013-0321 proceeding to the end of 2025.
c) Please list all the generating stations from part a) that are expected to realize an efficiency gain from 2026 to the end of 2031.

A1-Staff-8

Ref 1: Exhibit A1 / Tab 12 / Schedule 1
Ref 2: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1
Ref 3: EB-2020-0290, Exhibit D2 / Tab 2 / Schedule 3
Ref 4: Exhibit D2 / Tab 2 / Schedule 2 / p. 3

Preamble:

Reference 1 identifies a “Program Scope Review Board” while some Business Case Summaries in Reference 2 make reference to submitting “scope requests” to “the PSRB” to obtain approvals in relation to Refurbishment Outages. Specifically, the PSRB is noted in Tabs 9 and 14 to Reference 2. The same acronym is used in Reference 3, which describes scope planning for the Refurbishment Outages for Units 3, 1, and 4.

In Reference 4, OPG states that all the scope included within the OEB’s approval of the $4,800.2 million in-service addition for the refurbishment of Unit 2 was completed.

It is OEB staff’s understanding that in executing the Darlington Refurbishment Outages, OPG regularly convened a committee or other such group to manage and approve the scope of work that was executed.

Question(s):

a) Please confirm whether it was the Program Scope Review Board or some other group that was responsible for managing the scope of Darlington Refurbishment Outages. Please provide the OPG governance document that describes this group and includes their authorities and responsibilities as they related to the Refurbishment Outages.
b) Please summarize in plain language the role of the group or board from part a).
c) Please summarize the decisions the group or board from part a) made in relation to each Refurbishment Outage. Please do so with the following details:
   i. A count of work orders or work packages added to scope
   ii. A count of work orders or work packages removed from scope
   iii. A count of requests for work orders or work packages for scope injection that were denied
   iv. Group the summary using the Uniform Subject Index or System Classification Index, whichever may be applicable, at a resolution no-coarser than the system level (i.e., unless otherwise not possible, the first three digits of the five-digit system code are non-zero).

v. Please summarize any other decisions this group made in the course of executing the Unit 2 Refurbishment Outage.

A1-Staff-9

Ref 1: Exhibit A1 / Tab 3 / Schedule 3 / Chart 1
Ref 2: Exhibit A1 / Tab 2 / Schedule 2
Ref 3: EB-2020-0290, Decision and Order, November 15, 2021

Preamble:

At Reference 1, OPG presents the Nuclear Revenue Requirement Deficiency for the 2027 to 2031 period for OPG's nuclear facilities. Notes 3a to 8a provide references for the differences shown for each respective line and year in Chart 1.

In Reference 2, OPG outlines the approvals sought through this proceeding. Among these, this application seeks OEB approval of five distinct revenue requirements in each of 2027 to 2028 relating to OPG's nuclear facilities. This application also seeks five distinct revenue requirements in each of the same years relating to the Darlington New Nuclear Program (DNNP) facilities. Similarly, with Reference 3, by approving the Settlement Proposal, the OEB approved five distinct revenue requirements in each of 2022 to 2026 relating to OPG's nuclear facilities.

Also at Reference 2, the application seeks approval of a blended nuclear payment amount that reflects the combined nuclear revenue requirements relating to the OPG and the DNNP nuclear facilities.

Question(s):

a) Please reproduce Chart 1 with lines 4 through 9, the Changes in Revenue Requirement, on the basis of comparing the total cumulative five-year revenue requirement of EB-2020-0290 to the total cumulative five-year nuclear revenue requirement of EB-2025-0297. For the total cumulative nuclear revenue requirement for EB-2025-0297, please do so on the basis of the sum of OPG's nuclear facilities and the DNNP facilities.
b) Please further break-down the "Other" category so as to ensure that no individual driver of nuclear deficiency in part a) is smaller than "Other" on a five-year basis. In other words, please add additional categories and details as necessary so that "Other" is the smallest identified deficiency in the table.

c) Please update the accompanying narrative with respect to any new items arising from part b). For clarity, OEB staff is not requesting that the narrative for already identified items be updated in this interrogatory response.
d) Please also provide any additional information and explanation required to reconcile the EB-2020-0290 cumulative revenue requirement of $16,064.7 million and the proposed cumulative OPG nuclear and DNNP revenue requirement of $26,373.8 million.

A1-Staff-10

Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / Attachment 4
Ref 2: Exhibit A2 / Tab 3 / Schedule 1 / Attachments 1 -13

Preamble:

OPG has provided its Management's Discussion & Analysis and audited financial statements, as at and for the year ended December 31, 2024.

OPG has also provided its rating agency reports.

Question(s):

a) Please provide OPG's Management's Discussion & Analysis and audited financial statements, as at and for the year ended December 31, 2025, when available.
b) Please provide any rating agency reports that have been issued since OPG filed its current application in December 2025.

A1-Staff-11

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 p. 41

Preamble:

At Reference 1, OPG states it plans to issue annual public reports on both the Pickering Refurbishment Program (PRP) and the Darlington New Nuclear Program (DNNP) status.

Question(s):

a) Please confirm OPG will publish a final annual report on the status of Darlington Refurbishment Program (DRP) in June 2026.

A1-Staff-12

Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 16-17

Preamble:

Reference 1 summarizes the “Darlington Outage Management” audit, which has a Generally Effective (White) rating.

Question(s):

a) Please identify the outages that were the subject of this audit.
b) Please provide the identified Memorandum of Understanding that “will be prepared between Darlington Operations and DNR organizations, describing the process for transferring deferred WOs.” If it does not exist, please explain how the management action is “closed” without the memorandum being available.

A1-Staff-13

Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 22-23

Preamble:

Reference 1 summarizes the “Shared Services Re-imagine 1.0” audit, which has a Not Effective (Red) rating.

Question(s):

a) Please identify the projects or aspects from this Shared Services Re-imagine 1.0 that “are no-longer in use.”
b) Please confirm whether “Shared Services Re-imagine 1.0” was included in any EB-2020-0290 revenue requirements. If confirmed, please estimate those amounts.
c) Please confirm whether “Shared Services Re-imagine 1.0” was included in any EB-2025-0297 revenue requirements. If confirmed, please estimate those amounts. Please explain the amounts in the 2027-2031 period.
d) Please provide the post-implementation review.

A1-Staff-14

Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 49-52

Preamble:

Reference 1 summarizes the “Nuclear Work Order Materials Management” audit, which has a Not Effective (Red) rating.

Question(s):

a) Please identify the outages that were the scope of this audit or related to this audit.
b) The first finding appears to state that at the time of the audit, OPG Nuclear management was not monitoring the difference between the materials requisitioned and the materials used. If OPG disagrees with this characterization of the first finding, please correct and explain as necessary. Please estimate the difference in costs between what was requisitioned and what was used, as referenced in the audit, and identify the outages and/or the time period relating to that difference.

A1-Staff-15

Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 71-72
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Table 1
Ref 3: Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a, 1b, and 1c
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Tables 2a, 2b, and 3
Ref 5: Exhibit D2 / Tab 1 / Schedule 3 / Tables 2a to 2g, and 3

Preamble:

Reference 1 summarizes the “Long Lead Material Procurement & Supplier Capacity Risk Mitigation” audit, which has a Needs Improvement (Yellow) rating.

References 2 and 3 list the projects with budgets, for hydroelectric and nuclear, respectively, greater than or equal to $30 million.

References 4 and 5 list the projects with budgets or cumulative amounts as the case may be, for hydroelectric and nuclear, respectively, relating to projects with budgets less than $30 million.

Question(s):

a) For the hydroelectric projects listed in Reference 2, please identify all the projects that are reliant on long-lead materials.
b) For the nuclear projects listed in Reference 3, please identify all the projects that are reliant on long-lead materials.
c) For the hydroelectric projects that are collectively the projects relating to Reference 4, please estimate the proportion of the total budgets in each of 2027 to 2031 that relate to projects with long-lead materials.
d) For the nuclear projects that are collectively the projects relating to Reference 5, please estimate the proportion of the total budgets in each of 2027 to 2031 that relate to projects with long-lead materials.
e) Please generally explain how the findings of this audit relate to the hydroelectric projects with expenditures in 2027 to 2031 and explain how the findings are being addressed for these projects.
f) Please generally explain how the findings of this audit relate to the nuclear projects with expenditures in 2027 to 2031 and explain how the findings are being addressed for these projects.

A2-Staff-16

Ref 1: Exhibit A2 / Tab 2 / Schedule 1
Ref 2: *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the* G7, June 2025

Preamble:

Reference 1 provides an overview of OPG's business planning and budgeting objectives, and the planning process that underpins this Application.

Reference 2 is generally referred to as the Ontario Government's Integrated Energy Plan (the Plan).

Question(s):

a) The Minister's Message of Reference 2 explains that the Plan is designed with flexibility in mind. Please explain how OPG's business plan and approach to this application incorporates flexibility and uncertainty about the future as a design objective to that business plan.
b) Chapter 2 of Reference 2 describes how Ontario is adding new generation to ensure electricity remains, among other things, affordable. Please describe how OPG's business plan and approach to this application considered affordability as a design objective.
c) Chapter 8 to Reference 2 describes how the Ontario Government is supporting Indigenous equity partnerships. Please explain how OPG considered other equity partnerships, such as those highlighted in the Plan.
d) Chapter 9 of Reference 2 describes Ontario's objective to be a global energy superpower, exporting nuclear innovation and homegrown energy solutions. Please explain how OPG's business plan and approach to this application considers sharing the benefits from exporting nuclear innovation with the ratepayers who are contributing to the investments that are facilitating this export capability.

EXHIBIT B – RATE BASE

B1-Staff-17

Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Collectively, OPG's Annual Reporting of Estimated Earnings Before Taxes, where the 2024 Report is available at "2024 EBT Estimate Prescribed RRR Final. Non-Confidential.pdf"

Preamble:

At Reference 1, OPG reports the Prescribed Facility Rate Base for Regulated Hydroelectric. OPG also reports this rate base to the OEB through annual filing commitments.

OEB staff notes an apparent discrepancy for recent years between what has been filed in this proceeding compared to what has been reported annually. Specifically, Reference 1 line 6 appears to correspond exactly to Table 2a line 5a of the annual reporting for the years 2017 to 2021 (Reference 2), but not so in the years 2022 to 2024.

Question(s):

a) Please confirm the data in the following table. If not confirmed, please correct the table:

Table 1 – Comparison of Rate Base between Reference 1 and Reference 2 ($ millions)

	2017	2018	2019	2020	2021	2022	2023	2024
B1-1-1 Table 1, line 6	7,383.3	7,391.2	7,438.0	7,476.1	7,517.5	7,734.7	7,990.0	8,124.4
Rate Base from annual reporting	7,383.3	7,391.2	7,437.9	7,476.1	7,517.5	7,727.8	7,982.4	8,117.4

b) Please reconcile Reference 1, line 6 to the annual reporting, explaining any differences in reported prescribed hydroelectric rate base between the filed evidence and the annual reporting.

B1-Staff-18

Ref 1: Exhibit B2 / Tab 3 / Schedule 1 / Table 3a
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / pp. 1-3

Preamble:

At Reference 1, OPG provides the in-service dates, in-service amounts, and first-year weighting for certain hydroelectric projects reflected in rate base. OPG identifies 13 regulated hydroelectric in-service addition amounts greater than $50 million in the bridge years and IR term. At Reference 2, OPG provides the latest business case status for those projects.

Question(s):

a) For the projects listed below, please confirm that the latest Business Case Summaries (BCS) have been filed in the evidence. If not confirmed, update as required. Where required, please provide the updated BCS status and a copy of the latest BCS.

Table 1 – Selected Hydroelectric Projects

Source: Reference 1							Source: Reference 2
Line	**Project name**	**Project #**	**Facility / Region**	**In-service date**	**In-service amount ($M)**	**First-year weighting (months)**	**Latest BCS Status**
1	Otter G2 Capital Upgrade	82543	Otter Rapids / Eastern Region	15-Nov-25	61.9	1.5	Superseding Execution
2	Kakabeka Falls GS Redevelopment	86386	Kakabeka / Western Region	01-Apr-27	134.9	9	Full Release Execution
3	Kakabeka Falls GS Redevelopment	86386	Kakabeka / Western Region	01-Jul-27	165.7	6	Full Release Execution
4	BK1 G4 Refurbishment	86570	Sir Adam Beck 1 / Niagara Region	08-Jun-27	96.5	7	Full Release Execution

5	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2 / Niagara Region	01-Oct-28	176.5	3	G2 – Definition (Full)
6	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1 / Niagara Region	01-Oct-28	113.1	3	Full Release Definition
7	Matabitchuan GS Redevelopment	86387	Matabitchuan / Eastern Region	07-Aug-28	180.0	5	Full Release Execution
8	Kakabeka Falls GS Redevelopment	86386	Kakabeka Falls / Western Region	01-Dec-28	171.9	1	Full Release Execution
9	SAB1 Canal Isolation Preparedness Phase 1	89252	Sir Adam Beck 1 / Niagara Region	01-Mar-29	65.0	10	G2 – Definition (Full)
10	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2 / Niagara Region	01-Feb-29	176.5	11	G2 – Definition (Full)
11	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1 / Niagara Region	01-Mar-30	113.1	10	Full Release Definition
12	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2 / Niagara Region	01-Jul-30	172.1	6	Full Release Development
13	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2 / Niagara Region	01-Nov-30	172.1	2	Full Release Development

b) For each project listed in part a), please indicate whether the in-service date reflected in Reference 1 was established based on the most recent BCS approval or update identified in part a). Where it was not, please provide:
   i. the schedule update or other project controls document on which the in-service date was based.
   ii. a brief explanation of why the most recent BCS approval or update was not the basis for the in-service date reflected in Reference 1.

B1-Staff-19

Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / p. 8-9
Ref 2: Exhibit B2 / Tab 3 / Schedule 1 / Table 3a
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 41

Preamble:

In Reference 1, OPG states that, for regulated hydroelectric net fixed and intangible assets, rate base is generally determined using a mid-year average, but for in-service additions or adjustments greater than $50 million, the actual in-service month is used. In Reference 2, OEB staff notes that Project 87768, Sir Adam Beck 2 G20/G19 Refurbishment, is reflected in rate base using in-service dates of October 1, 2028 and February 1, 2029. In Reference 3, OPG indicates that turbine contractor selection was not yet complete, that Gate 3 funding release was anticipated in Q4 2025, that a fully integrated resource-loaded schedule was expected be developed, and that key project risks include engineering delays, procurement of long-lead materials, system integration complexity, and interconnection assessments.

Question(s):

a) Please confirm whether the Business Case Summary (BCS) provided at Reference 3 is the most recent BCS for Project 87768. If not, please provide the most recent BCS.
b) OPG states that the Gate 3 funding release for Project 87768 was anticipated in Q4 2025. Please confirm whether the Gate 3 funding release has been completed. If not, please explain the reason it has not been completed, provide the current expected approval date, and indicate whether this has affected, or may affect, the in-service dates reflected in hydroelectric rate base.
c) If the BCS provided at Reference 3 is the most recent BCS, please confirm whether the deliverable target dates shown in that BCS are the latest target dates for the project. If they are not, please provide the updated deliverable target dates.
d) Please confirm that the following in-service timing assumptions for Project 87768 are reflected in hydroelectric rate base (or if not confirmed please explain):
   i. October 1, 2028, for an in-service addition of $176.5 million, and
   ii. February 1, 2029, for an in-service addition of $176.5 million.
e) For each in-service date identified in part d), please identify the corresponding deliverable or milestone and target date from the most recent BCS, or from the updated deliverable target dates provided in response to part c), that supports the in-service date reflected in rate base.
f) Please identify the key risks currently facing Project 87768 that could affect the in-service dates reflected in rate base. For each such risk, please indicate whether it has materialized to date and, if so, whether it has affected the current project schedule.

B1-Staff-20

Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / pp. 2-3

Preamble:

In Reference 1, OPG states that the early in-service additions of the Darlington Refurbishment Units is one of the key drivers of increased OPG Nuclear rate base in the 2022-2026 term from what was presented in EB-2020-0290.

Question(s):

a) Please confirm how OPG defines the in-service date for the Darlington Refurbishment Units. Please confirm that OPG proposes the same definition for the Pickering Refurbishment Units. If not confirmed, please explain.
b) In accordance with part a), please identify the in-service date of each of Darlington Refurbishment Units 1, 3, and 4. For each unit, please also confirm the in-service date approved in EB-2020-0290.
c) For each of Darlington Refurbishment Units 1, 3, and 4, please identify the Revenue Requirement increase in each of 2027 to 2031 due to the early in-service date. Please provide the supporting tables in excel format.
d) Please confirm that OPG is stating in Reference 1 that there are anticipated Capacity Refurbishment Variance Account (CRVA) balances for future recovery due to the early return to service of Unit 4, regardless of whether the Darlington Refurbishment Program cost was over the approved budget.
e) OEB staff notes that, as of 11:00AM EST on March 8, 2026, Darlington Nuclear Generating Station Unit 4 is generating approximately 666 MW. Please provide the CRVA details showing CRVA additions that are anticipated based on the early return to service of Unit 4.

EXHIBIT C – CAPITALIZATION, COST OF CAPITAL AND NUCLEAR LIABILITIES

C1-Staff-21

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 9
Ref 2: Exhibit I1 / Tab 2 / Schedule 1 / Table 2
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1-5

Preamble:

For the years 2028-2031, OPG proposes that its hydroelectric payment amount be adjusted annually according to a mechanistic custom price-cap adjustment, using a formula that includes a Custom Capital Factor.

At Exhibit I1, OPG has shown its “Calculation of Capital Factor for Regulated Hydroelectric Facilities” which includes the following amounts that have been allocated from Exhibit C1. OEB staff has prepared Table 1 below showing these amounts.

Table 1 – Cost of Capital Amounts included in the Calculation of Capital Factor ($ millions)

	2028	**2029**	**2030**	**2031**
Short-Term Debt	$7.3	$8.0	$7.8	$6.7
Long-Term Debt	$215.1	$246.3	$265.1	$280.2
Return On Equity	$458.9	$512.3	$543.4	$568.8

Exhibit C1 shows the “Summary of Capitalization and Cost of Capital – OPG” for the years 2027 to 2031, which itemizes OPG’s proposed recovery of short-term debt, long-term debt, and return on equity. These amounts are included in the proposed regulated hydroelectric facilities’ revenue requirement for 2027 and the proposed nuclear facilities’ revenue requirements for 2027 to 2031. These amounts are also embedded in the proposed regulated hydroelectric facilities’ price-cap adjustment for 2028 to 2031 (specifically in the Capital Factor).

Question(s):

a) Please confirm that “Table 1 – Cost of Capital Amounts included in the Calculation of Capital Factor” is accurate. Please update the table as applicable and explain any changes made.
b) If OPG’s proposed Capital Factor is not approved by the OEB, how does OPG propose to recover the cost of capital amounts in Table 1 (or a revised Table 1)

that are provided in its Exhibit C1 evidence for the years 2028 to 2031? Please explain.

C1-Staff-22

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / p. 1
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Ref 3: Exhibit A2 / Tab 2 / Schedule 1 / Attachment 1 / p. 3
Ref 4: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement / Exhibit 0 / Tab 1 / Schedule 1 / p. 24, July 16, 2021

Preamble:

OPG stated that it expects to receive a shareholder equity injection from the Province of Ontario totalling $5 billion over the 2025-2027 period. However, OEB staff notes that this $5 billion injection is not discussed in OPG's expert report titled "Common Equity Ratio Study", authored by Concentric.

OPG stated that equity injections directly reduce OPG's borrowing requirements and benefit ratepayers by helping to ensure cost effective financing for OPG's investments in the electricity system. OPG also stated that under the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period.

In the current proceeding, OPG is requesting a capital structure of 52% equity and 48% debt. In the last payments proceeding, the Parties agreed for the capital structure to remain unchanged from EB-2016-0152 (OPG's previous payments proceeding) at 45% equity and 55% debt for the purposes of determining the nuclear revenue requirements for the 2022-2026 period.

OEB staff notes below that some of the questions are directed to Concentric.

Question(s):

a) Please explain why a shareholder equity injection from the Province of Ontario totalling $5 billion over the 2025-2027 period is required, other than reducing OPG's borrowing requirements.
b) Concentric: Please explain why the $5 billion injection is not discussed in OPG's expert report titled "Common Equity Ratio Study", authored by Concentric.
c) Concentric: Please provide Concentric's views on this $5 billion injection matter.

d) Please explain whether the $5 billion injection (which will dilute the existing shareholders' equity) is a key driver behind the requested 52% equity thickness, an increase from the current OEB-approved 45% equity thickness. OEB staff did not see the $5 billion injection being listed as a key driver in OPG's evidence.

C1-Staff-23

Ref 1: Exhibit A2 / Tab 2 / Schedule 1 / p. 13
Ref 2: Exhibit A2 / Tab 1 / Schedule 1 / Attachment 1 / p. 19
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / p. 2

Preamble:

OPG stated that its 2025-2031 Business Plan reflects OPG's announced equity partnership with Canada Growth Fund and Building Ontario Fund as minority investors in the Darlington New Nuclear Program (DNNP), which, subject to satisfaction of conditions, is expected to contribute approximately $3 billion of funding.

OPG stated that in October 2025, up to $1 billion from the Building Ontario Fund and up to $2 billion through the Canada Growth Fund have been secured, subject to the satisfaction of certain conditions.

DNNP LP is requesting a capital structure of 100% equity and 0% debt. Section 13.(1) of Ontario Regulation 53/05 establishes the DNNP generator capital structure variance account.

Question(s):

a) Please explain why a shareholder equity injection from the Canada Growth Fund and Building Ontario Fund totalling $3 billion is required.
b) Please explain whether the $3 billion injection (which will dilute the existing partnerships' interests) is a key driver behind the requested 100% equity thickness for the DNNP. OEB staff did not see the $3 billion injection being listed as a key driver in DNNP's evidence.
c) Despite the establishment of the DNNP Generator Capital Structure Variance Account, please explain from a ratepayer perspective why DNNP LP requested capital structure of 100% equity (which earns the OEB's allowed Return on Equity (ROE)) and 0% debt is reasonable, given that based on the OEB's cost of

capital parameters set for 2026 rates, the allowed ROE is 9.11% which is much higher than:

i. the deemed long-term debt rate of 4.73%; and
ii. the deemed short-term debt rate of 2.72%

d) Despite the establishment of the DNNP Generator Capital Structure Variance Account, please confirm that the partners of DNNP LP are incented to have a higher equity component of the DNNP capital structure than debt component, given the above noted percentage differences in the allowed ROE, deemed long-term debt rate, and deemed short-term debt rate. If this is not the case, please explain.

C1-Staff-24

Ref 1: Exhibit A2 / Tab 3 / Schedule 1 / Attachment 9

Preamble:

OEB staff notes Moody's June 30, 2025 credit opinion which states the following:

> Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 stable).

OEB staff notes below that the question below is directed to Concentric.

Question(s):

a) Concentric: OEB staff notes that Concentric considered the latest Moody's report. Please explain how it factored into Concentric's analysis.

C1-Staff-25

Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Tables 3a & 3b
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1-5

Preamble:

OPG provided the following tables related to revenue deficiencies:

- "Summary of Revenue Deficiency - Regulated Hydroelectric - January 1, 2027 to December 31, 2027"
- "Summary of Revenue Deficiency - OPG Nuclear Facilities - January 1, 2027 to December 31, 2031"

OPG provided the following tables related to cost of capital:

- Summary of Capitalization and Cost of Capital – OPG
  - Calendar Year Ending December 31, 2031
  - Calendar Year Ending December 31, 2030
  - Calendar Year Ending December 31, 2029
  - Calendar Year Ending December 31, 2028
  - Calendar Year Ending December 31, 2027

Question(s):

a) Please provide a table that shows the forecast revenue deficiency for each of 2027 through 2031, as shown in the above tables for hydroelectric and nuclear, along with the forecast revenue deficiency for each of 2027 through 2031, if the common equity component of rate base was maintained at 45% (as opposed to the requested 52% equity ratio in the current application).

C1-Staff-26

Ref 1: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement / Exhibit 0 / Tab 1 / Schedule 1 / pp. 15, 23 & 36, July 16, 2021

Preamble:

In the settlement agreement in OPG's last payments proceeding, the following was agreed to by parties:

> …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.

Question(s):

a) Please confirm that in the current proceeding, OPG included the appropriate portion of the nuclear net plant rate base amount subject to a return on equity (ROE) equivalent to the OEB-approved long-term debt cost rate for OPG over the period from January 1, 2022 to December 31, 2036.
b) If this is not the case, please explain.

C1-Staff-27

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 8a, 9a, 10a, 11a, 12a
Ref 2: Exhibit I1 / Tab 1 / Schedule 1 / p. 2
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / pp. 1 & 50

Preamble:

In Exhibit C, OPG has provided the actual regulated return on equity (ROE) in dollar terms, but not percentage terms for 2020-2024.

In Exhibit I, OPG has provided “Chart 1 - Actual and Forecast ROE” which provide the actual and allowed ROEs in percentage terms.

In Exhibit H, OPG noted that the Earnings Sharing Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record 50% of any regulated earnings for OPG’s combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative 5-year period from January 1, 2022 to December 31, 2026. OPG stated that no entries will be recorded in this account until following the completion of the above five-year period, if applicable. OPG also stated that this account has a zero balance as at December 31, 2024.

Question(s):

a) Please provide the actual regulated ROE (in both dollar terms and percentage terms) and the allowed ROE for each year 2020-2025.

b) Please reconcile the actual regulated ROE in dollar terms in Exhibit C, to the percentage terms in Exhibit I.
c) Please confirm that OPG will be recording entries in the Earnings Sharing Deferral account following the completion of the five-year period ending December 31, 2026, given that in "Chart 1 - Actual and Forecast ROE", OPG has earned more than 100 basis points in actual earnings over the allowed ROEs in percentage terms (in some calendar years). If this is not the case, please explain.

C1-Staff-28

Ref 1: EB-2024-0063, Generic Cost of Capital Decision and Order, March 27, 2025, pp. 71, 80, 81

Preamble:

In the generic cost of capital decision, the OEB stated that for OPG, neither the deemed long-term debt rate (DLTDR) or deemed short-term debt rate (DSTDR) will be applied as a cap on the unfunded portion of the capital structure (the portion of the capital structure to reach 100%). The OEB noted that it will assess whether the cost of debt has been prudently incurred, and the DLTDR and DSTDR will be considered as part of that assessment.

The OEB also stated that OPG is expected to demonstrate that it has been prudent in its debt management. In determining that prudence, the OEB will assess the management of debt and the processes the utility has in place to manage their treasury functions.

Question(s):

a) Please explain how OPG's costs of long-term debt included in its 2027-2031 revenue requirements have been prudently incurred, in the context of the OEB's DLTDR of 4.73% set for 2026 rates.
b) Please explain how OPG's costs of short-term debt included in its 2027-2031 revenue requirements have been prudently incurred, in the context of the OEB's DSTDR of 2.72% set for 2026 rates.
c) Please explain how OPG has been prudent in its debt management, including its management of debt and the processes OPG has in place to manage its treasury functions.

C1-Staff-29

Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / pp. 1, 5-7

Preamble:

OPG stated that it has made updates to the methodology used to determine the cost of planned long-term debt issues in this application, compared to previous proceedings.

OPG noted that previously IHS Markit's Global Insight Economics (Global Insight) was used as a third-party market source for forecast Government of Canada (GoC) bond rates.

OPG also noted that there is an increased volume of planned debt issues, as well as observed notable divergence in forecast data between Global Insight and other economist views. Over the 2025-2031 period, OPG forecasts issuing approximately $10 billion in long-term debt that is wholly or partially attributed to its regulated operations and which will support the planned capital investments. OPG stated that this does not include the forecast long-term debt issues attributed to OPG's anticipated cash contributions to DNNP LP, beginning in 2026.

OPG stated that the forecast in this proceeding has been determined using an equally weighted combination of 10-year and 30-year durations.

OPG stated that Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy.

Question(s):

a) Please explain why there is an "increased volume of planned debt issues", other than supporting planned capital investments.
b) Please explain how OPG concluded it was appropriate to use "an equally weighted combination of 10-year and 30-year durations" to determine its forecast, rather than other proportions.
c) Please explain why OPG is stating in the current application that there was an "observed notable divergence in forecast data between Global Insight and other economist views" and not in prior proceedings.

d) Please explain whether OPG attempted to use different methodologies to develop long-term debt costs and short-term debt costs, other than using Bloomberg forecasts, given OPG's statement that "Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy."

C1-Staff-30

Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / pp. 5-7

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed long-term debt methodology, compared to the historic methodology used in prior applications.

Table 1 – Comparison of Long-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Proportions of 10-year and 30-year durations	As Global Insight GoC bond rate forecast was limited to 10-year bonds, a simplifying assumption was made that all planned long-term debt issues would have a tenor of 10 years.	OPG's actual debt issues had been (and continue to be) a combination of 10-year and 30-year tenors.	The forecast has been determined using an equally weighted combination of 10-year and 30-year durations.

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2025-2027	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Bloomberg Bond Yield Median Forecast (Ticker: BYFC)
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2025-2027	n/a	Actual 30-year GoC yields were different than forecasted yield	Forward GoC rates from the Bloomberg ticker YCGT0007
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2028-2031 The Bloomberg Bond Yield Median Forecast was not available for 2028-2031	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward GoC rate for 2026 and 2027, to the Bloomberg forward GoC rate.
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2028-2031	n/a	Actual 30-year GoC yields were different than forecasted yield	Forward GoC rates from the Bloomberg ticker YCGT0007
Source of Credit Spread	The term-matched credit spread used in the forecast was	Actual credit spreads were different from	A three-year historical average of the term-

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
	observed at a point in time, based on quotes from the major banks, when preparing the respective payment amounts application.	forecasted credit spread	matched credit spread obtained from the six major Canadian banks used as the basis of the forecast.

Question(s):

a) Please confirm that "Table 1 – Comparison of Long-Term Debt Updated Methodology versus Historic Methodology" is accurate. Please update the table as applicable and explain any changes made.
b) Please explain OPG's suggestion that the forecast inferred would be applied to the Bloomberg forward GoC rate. OEB staff is not clear whether this would be a circular activity, given that the Bloomberg forward GoC rate is also included in the forecast inferred average difference.

C1-Staff-31

Ref 1: Exhibit C1 / Tab 1 Schedule 2 / pp. 5-7

Preamble:

OPG stated that historically, the term-matched credit spread used in the forecast was observed at a point in time, based on quotes from the major banks, when preparing the respective payment amounts application. In this application, OPG has used a three-year historical average of the term-matched credit spread obtained from the six major Canadian banks as the basis of the forecast.

OPG stated that this improves the forecasting methodology by better capturing a range of market conditions that have materialized in the previous years and could potentially materialize in the future, rather than relying on point-in-time information.

OPG's 10-year and 30-year credit spread based on historical three-year average data is 135 basis points and 160 basis points, respectively.

Question(s):

a) Please provide support on a high-level basis OPG's historical three-year average data of 135 basis points and 160 basis points, obtained from the six major Canadian banks used as the basis of the forecast.
b) Please explain OPG's statement that its new methodology improves its forecasts, given that both the old methodology and new methodology use data taken at a point-in-time.

C1-Staff-32

Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / p. 9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

OPG stated that in 2022, it entered into a $970 million non-revolving term credit facility with the Canada Infrastructure Bank (CIB). The facility was made available to fund part of the expenditures required to prepare for the construction of the Darlington New Nuclear Program (DNNP). The debt outstanding under the CIB facility will remain with OPG following the transfer of the DNNP facilities to DNNP LP.

OPG stated that as it will no longer be associated with OPG's prescribed facilities, this debt is excluded from that attributed to OPG's regulated operations. Instead, under the expected partnership arrangements, OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026.

OPG stated that this forecast credit or charge is reflected in the DNNP LP's proposed revenue requirements over the IR term (Ex. F2-1-1, Table 1b, line 7). OEB staff notes that this is specifically included as "Asset Service Fees" in DNNP's OM&A.

Question(s):

a) Please explain why OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026.

C1-Staff-33

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1 – 6
Ref 2: Exhibit C1 / Tab 1 / Schedule 2 / p. 6

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed long-term debt rate requests, which were derived using OPG's current methodology (versus the methodologies used in prior applications).

Table 1 – Summary of OPG's Proposed Long-Term Debt Rates

Year	Proposed Long-Term Debt Rate
2026	4.42%
2027	4.58%
2028	4.78%
2029	4.90%
2030	4.97%
2031	4.98%

In a footnote, OPG suggested that the Bloomberg data incorporated into the above-noted proposed long-term debt rates were obtained on November 21, 2025.

Question(s):

a) Please confirm that “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates” is accurate.
b) If this is not the case, please update “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates” and explain any changes made.
c) Please update “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates” using OPG’s methodology from its last payments proceeding (by adding a new column) and summarize the assumptions made to derive these long-term debt rates.
d) With the results of part c), please re-run the proposed revenue requirements for 2027-2031 using the old methodology.

C1-Staff-34

Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / p. 2

Preamble:

OPG stated that it expects most of its borrowing needs over the IR term to be sourced through its Medium-Term Note program in the Canadian bond market. OPG is also planning to establish the ability to access US bond markets during the IR term, as part of its funding risk diversification strategy to proactively manage the likelihood that its funding requirements will exceed the issuance capacity in the Canadian bond markets. OPG intends to accomplish this by registering as a Foreign Private Issuer with the U.S. Securities and Exchange Commission (SEC). OPG stated that the cost of debt assumptions in the current application are based on bond issuances in the Canadian market.

OEB staff notes that IFRS 20, *Regulatory Assets and Regulatory Liabilities*, is expected to be issued by the International Accounting Standards Board (IASB) by Q2 2026.

Question(s):

a) Please explain why it is likely that OPG's "funding requirements will exceed the issuance capacity in the Canadian bond markets."
b) Please explain whether registering with the SEC would prohibit OPG to move to IFRS from US GAAP for financial reporting purposes and regulatory reporting and rate-making purposes.

C1-Staff-35

Ref 1: Exhibit C1 / Tab 1 / Schedule 3 / pp. 2-3

Preamble:

For the source of the forecasted 3-month T-Bill rate for 2025-2027, OPG has used the equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC).

For the source of the forecasted 3-month T-Bill rate for 2028-2031, the forecast has been inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.

Question(s):

a) Please confirm that OEB staff's understanding of the sources of the forecasted 3-month T-Bill rate for 2025-2031 noted in the above Preamble is correct. If this is not the case, please explain.
b) Please explain why it is appropriate to use the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) to develop both OPG's long-term debt rates and short-term debt rates.
c) OEB staff was unable to find the relevant data for the tickers BYFC, YCGT0007, and YCSW0147 on Bloomberg's platform, despite the OEB holding a Bloomberg subscription. Please explain, step-by-step, how OPG derives the data from these tickers, and how they are included in the derivation of OPG's long-term debt costs and short-term debt costs. For example, instead of using the ticker BYFC, please explain whether OPG instead used the following Bloomberg tickers to develop its forecasts:
    i. EC30CA Q426 Index for its Canada 30-Year Note Forecast

ii. ECXYCA Q426 Index for its Canada 10-Year Bond Yield Forecast
iii. EC3MCA Q426 Index for its Canada 3-month Interest Rate Forecast

d) Please explain why OPG has used the equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC), instead of different proportions.

C1-Staff-36

Ref 1: Exhibit C1 / Tab 1 Schedule 3 / pp. 2-3

Preamble:

OPG stated that historically, the corporate spread used in the forecast was observed at a point in time during the preparation of the respective payment amounts application.

In this application, OPG has used an average corporate spread of OPG's 3-month term commercial paper over the Overnight Index Swap (OIS) rate observed since the OIS became the benchmark for commercial paper rates in mid-2024.

OPG noted that the revised approach improves the forecasting methodology by better capturing a range of market conditions that have materialized in the previous months and could potentially materialize in the future, rather than relying on point-in-time information.

OPG stated that the resulting corporate spread is 17 basis points over the OIS rate.

Question(s):

a) Please provide support on a high-level basis of OPG's corporate spread of 17 basis points over the OIS rate.
b) Please explain OPG's statement that its new methodology improves its forecasts, given that both the old methodology and new methodology use data taken at a point-in-time.

C1-Staff-37

Ref 1: Exhibit C1 / Tab 1 Schedule 3 / pp. 2-3
Ref 2: EB-2020-0290, Exhibit C1 / Tab 1 / Schedule 3 / p. 2, December 31, 2020

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed short-term debt methodology, compared to the historic methodology used in prior applications.

Table 1 – Comparison of Short-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast 3-month T-Bill rate for 2025-2027	Global Insight forecast used as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.	Actual 3-month bankers' acceptance rates were different than forecasted rate	Equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC)
Source of Forecast – 3-month T-Bill rate for 2028-2031 The Bloomberg Bond Yield Median	Global Insight forecast used as the basis for the bankers' acceptances interest rate forecast after	Actual 3-month bankers' acceptance rates were different than forecasted rate	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Forecast was not available for 2028-2031	adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.		Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.
Source of Credit Spread	The corporate spread forecast over the IR term was based on the corporate spread of 5 basis points over the Canadian bankers' acceptances rate at the time of the application.	Actual credit spreads were different from historic forecasted credit spread	An average corporate spread used, based on OPG's 3-month term commercial paper over the OIS rate observed since the OIS became the benchmark for commercial paper rates in mid-2024

Question(s):

a) Please confirm that "Table 1 – Comparison of Short-Term Debt Updated Methodology versus Historic Methodology" is accurate. Please update the table as applicable and explain any changes made.
c) Please explain OPG's suggestion that the forecast inferred would be applied to the Bloomberg forward OIS rate. OEB staff is not clear whether this would be a circular activity, given that the Bloomberg forward OIS rate is also included in the forecast inferred average difference.

C1-Staff-38

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1 – 6
Ref 2: Exhibit C1 / Tab 1 / Schedule 3 / p. 2

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed short-term debt rate requests, which were derived using OPG's current methodology (versus the methodologies used in prior applications).

Table 1 – Summary of OPG's Proposed Short-Term Debt Rates

Year	Proposed Short-Term Debt Rate
2026	2.47%
2027	2.79%
2028	2.93%
2029	3.07%
2030	3.22%
2031	3.39%

In a footnote, OPG suggested that the Bloomberg data incorporated into the above-noted proposed short-term debt rates were obtained on November 21, 2025.

Question(s):

a) Please confirm that "Table 1 – Summary of OPG's Proposed Short-Term Debt Rates" is accurate.

b) If this is not the case, please update “Table 1 – Summary of OPG’s Proposed Short-Term Debt Rates” and explain any changes made.
c) Please update “Table 1 – Summary of OPG’s Proposed Short-Term Debt Rates” using OPG’s methodology from its last payments proceeding (by adding a new column) and summarize the assumptions made to derive these short-term debt rates. Please perform this task to the best of OPG’s ability, given that bankers acceptances have been phased out.
d) With the results of part c), please re-run the proposed revenue requirements for 2027-2031 using the old methodology.

C1-Staff-39

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / p. 2
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / pp. 58 & 72
Ref 3: Exhibit A1 / Tab 4 / Schedule 4 / pp. 6-7
Ref 4: EB-2024-0063, OEB Cost of Capital Generic Proceeding, Decision and Order, March 27, 2025, pp. 95-96

Preamble:

OPG noted that Section 13(1) of Ontario Regulation 53/05 establishes the Darlington New Nuclear Program (DNNP) generator capital structure variance account (DGCSVA) which requires the OEB to provide, using this variance account, the recovery of the revenue requirement impacts arising from DNNP LP’s actual capital structure and cost of debt, subject to such debt having been prudently incurred. OPG proposes an effective date of January 1, 2026.

O. Reg. 53/05 states:

> 13. (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that, until the effective date of the first DNNP post-construction payment order, records differences between,
>
> > (a) the revenue requirement impacts arising from the DNNP generator’s capital structure and cost of debt reflecting the actual amount and cost of borrowing issued by it; and
> >
> > (b) the amount of the revenue requirement impacts arising from the capital structure and the cost of debt that were included in payments made

under section 78.1 of the Act to the DNNP generator. O. Reg. 315/25, s. 12.

(2) The account shall not include any amount included in a variance account established under subsection 11 (1) or 12 (1). O. Reg. 315/25, s. 12.

(3) The DNNP generator shall record interest on the balance of the account as the Board may direct. O. Reg. 315/25, s. 12.

OPG stated that the manner in which the account entries are calculated needs to consider the interaction with the Darlington New Nuclear Project Variance Account re Development (DNNPVARD). The DNNPVARD will record the revenue requirement impact of differences between actual and forecast capital costs for the DNNP (i.e., measured as the difference between the actual and forecast rate base values) using the forecast cost of capital parameters approved by the OEB.

For the DGCSVA, OPG proposes that the revenue requirement impacts arising from:

- The amount for s. 13(1) (a) above be calculated by applying a debt component (and interest cost) equal to the actual amount of DNNP LP's debt outstanding (and interest cost) at the time to the actual rate base value (i.e., the same actual rate base value used in the DNNPVARD variance calculation), with the remaining portion of such actual rate base value representing the equity component.
- The amount for s. 13(1) (b) above would be calculated by applying the forecast cost of capital parameters (including percentage capital structure) approved by the OEB to the actual rate base value.

Question(s):

a) Please explain why the DNNPVARD will capture impacts relating to the OEB-approved rate base value (i.e., forecasted rate base), but s. 13(1) (b) above will capture impacts relating to the actual rate base value.
b) Please explain why an effective date of January 1, 2026 is appropriate, given the payment amounts are proposed to be effective January 1, 2027.
c) Please explain whether simple interest will be calculated on the opening monthly balance of the DGCSVA, using the OEB-approved EB-2024-0063 interest rate methodology, as per the OEB's generic proceeding on Cost of Capital, further to what is stated by OPG in "Section 9.0 Interest" of Exhibit H.

C1-Staff-40

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 49

Preamble:

Concentric provided in its report “Figure 10: Pro Forma Regulated-Only Credit Metrics”. This figure provides the pro forma regulated-only FFO/Debt and CFO/Debt metrics over the IR Term at OPG’s current equity thickness of 45.0% and at Concentric’s recommended equity thickness of 52.0%. The years 2027-2031 are shown in this table.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Please provide the assumptions used to generate Figure 10.
b) Concentric: Please explain whether the availability of 2025 fiscal year data would change the metrics shown in Figure 10.
c) Concentric: If yes, please update Figure 10, including describing the assumptions used.

C1-Staff-41

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 5-7; 13-14; 33

Preamble:

Polar Star stated the in-service date for Unit 1 is expected to be October 2030, after which the special purpose vehicle (SPV) will seek to raise investment grade non-recourse debt in the capital markets as soon as practicable.

Polar Star stated that issuing a bond for a first-time issuer such as the SPV requires extensive preparation, which is expected to take at least 6-9 months after Unit 1 comes into service.

Polar Star noted that there may also be advantages for the SPV to defer the first bond issuance to potentially obtain better terms for the financing based on a longer operating history.

Polar Star stated that the specific length of operating history will depend on what happens during the months following the in-service date including: (i) the number, duration and reason for any unplanned outages; and (ii) actual versus forecast electricity generation levels.

Polar Star stated that its estimated minimum 6–9-month period is the actual time to obtain credit ratings, negotiate documentation, market and issue a bond. However, it does not incorporate the longer period that is very likely required to observe Unit 1 in operation to partially mitigate first of a kind (FOAK) risk and thus enable a successful offering. It also does not take into account that the SPV may strategically decide to defer the offering by some months or a year-plus to secure better terms.

Polar Star concluded that the limited spread upside for a bondholder relative to risk and the unquantifiable magnitude of the FOAK risks will make if very challenging to issue non-recourse investment grade bonds within 12-18 months of the in-service date of Unit 1. In Polar Star's view, there is a low to very low probability of a successful offering of these bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP.

OEB staff notes below that some of the questions are directed to Polar Star.

Question(s):

a) Please explain whether the in-service date for Unit 1 is still expected to be October 2030. If this is not the case, please explain.
b) Polar Star: Please provide an update (if any) on timing of raising investment grade non-recourse debt since the application was filed.
c) Polar Star: Please explain whether the first issuance is expected to take 6-9 months after Unit 1 comes into service, or within 12-18 months, or may be "strategically" deferred even further.
d) Polar Star: Please explain what time period Polar Star is suggesting regarding the deferral of the first bond issuance "based on a longer operating history."
e) Polar Star: Please explain why Polar Star has highlighted operating history risks regarding DNNP unplanned outages and electricity generation levels when OPG in general is faced with these risks. Please confirm that it is due to FOAK technology. If this is not the case, please explain.

C1-Staff-42

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 31

Preamble:

Polar Star noted that there are about 50 utilities, infrastructure, energy infrastructure, and power generation bond issuers in Canada with broadly marketed investment grade bonds outstanding, where credit spreads are regularly tracked and broadly communicated to investors.

Polar Star provided Table III, Canadian Investment Grade Utility Issuers (~50 issuers), which show the highest and lowest credit spreads for these bond issuers as of mid-October 2025, also including OPG bonds.

Polar Star assumed that the special purpose vehicle (SPV) 10-year debt (the longest maturity most likely available in an initial offering) could be priced with a spread 20% higher than the highest spread from the ~50 issuers.

Polar Star stated that the incentive for SPV debt investors is at most ~1% per annum relative to buying OPG bonds. Polar Star noted that given this overall limited potential upside, potential bond investors are very unlikely to be willing to take any unusual risks.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Please explain how the following were calculated at a high level:
   i. The 20% higher spread
   ii. The 1% per annum incentive
b) Polar Star: Please explain if the SPV (i.e., DNNP) debt could be structured to provide more potential upside to potential bond investors, but also reducing costs to DNNP ratepayers.

C1-Staff-43

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 5 & 6

Preamble:

Polar Star stated the following:

> The in-service date for Unit 1 is expected to be October 2030, after which the SPV will seek to raise investment grade non-recourse debt in the capital markets as soon as practicable.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: What forms of debt financing, if any, could be available to DNNP LP other than non-recourse debt?
b) Polar Star: What determines when investment grade debt issuances are "practicable"?
c) Polar Star: Please explain whether other forms of debt financing could be raised sooner than “investment grade non-recourse debt” and whether the terms would typically be more or less favourable.

C1-Staff-44

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 9, 18, and 19

Preamble:

Polar Star stated the following:

> Importantly, all four SMRs are expected to be within a common SPV financing framework and there will be interaction risks between the various SMR units, with bond investors likely having at least some risk exposure to all units that are approved and constructed…
>
> …As Units 2, 3 and 4 come online, diversification will increase, resulting in reduced concentration risk to bondholders, although multiple SMR units could be susceptible to experiencing the same problems/defects (but most likely at different times given different in-service dates). On the other hand, any challenges associated with the first unit operations may well be addressed prior to the completion of Units 2, 3 or 4. Overall, while there is a limit to the benefit of diversification for identical assets, the risk is clearly greatest when there is only one unit in operation.”

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: The report refers to interaction risks (p. 9) associated with the construction of multiple small modular reactors (SMR) units, as well as risk reduction from having multiple plants (p. 18-19). What is the net effect on risk of these countervailing risks?

C1-Staff-45

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 19

Preamble:

Polar Star stated the following:

> I expect that it will take multiple bond issues and some years to achieve an optimal capital structure for the SPV.

OEB staff notes below that the question is directed to Polar Star.

Question(s):

a) Polar Star: What is an "optimal capital structure" for the Darlington New Nuclear Program (DNNP)?

C1-Staff-46

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 7

Preamble:

Polar Star stated the following:

> For the reasons stated herein, but primarily due to FOAK nuclear technology risk and related operating risk, I believe that there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Please elaborate on the meaning of the phrase “successful offering” in this statement.
b) Polar Star: How was the "12-18 month" period after in-service date determined to be the appropriate time to issue debt?

C1-Staff-47

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 33

Preamble:

Polar Star stated the following:

> Having a reasonable operating period after the in-service date is, I believe, critical for a successful first bond offering.

OEB staff notes below that the question is directed to Polar Star.

Question(s):

a) Polar Star: What is the typical amount of time in service before a company will issue bonds to finance new capital infrastructure projects?

C1-Staff-48

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 29

Preamble:

Polar Star stated the following:

> It may be undesirable, even if technically feasible, for the SPV to negotiate the final terms of the trust indenture too early, as the perceived risk profile would likely be better a year or more after the inservice date. Deferring the indenture for some such period could therefore lead to a more SPV friendly trust indenture, resulting in increased flexibility and the avoidance of potential future costs associated with modifying the trust indenture, or worse, having to create a more expensive future financing structure (e.g., senior and subordinated debt) due to restrictions in the trust indenture.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Can trust indentures be renegotiated? (For example, could Darlington New Nuclear Program (DNNP) issue bonds with a relatively stringent trust indenture, but, following 12-18 months of successful in-service use of the plant, renegotiate a new trust indenture on new terms?)
b) Polar Star: Please explain the likelihood of any renegotiating of an initial trust indenture impacting the terms of future trust indentures.
c) Polar Star: Please explain whether the terms would typically be more or less favourable.

C1-Staff-49

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 37

Preamble:

Concentric stated the following:

> Some stations will require a full redevelopment of the site, with larger project scope and extensive demolition. For some of these assets, these major refurbishment or rehabilitation investments represent first-of-a-kind work on equipment over 100 years of age. One risk associated with projects of these types and on aged assets is the uncertainty of not knowing the exact condition of some of the more inaccessible components of each facility when the work begins. This can lead to increased costs or extended construction schedules (or both), depending on the conditions encountered.

OEB staff notes below that the question is directed to Concentric.

Question(s):

a) Concentric: What are the first-of-a-kind work planned for the hydroelectric refurbishment?

C1-Staff-50

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 50

Preamble:

Concentric stated the following:

> As noted earlier in this report, OPG is rated A(low) (DBRS)/BBB+(S&P)/A3 (Moody's). There is evidence, however, that OPG is perceived from a financial perspective to be of higher risk than similarly rated utilities, as demonstrated through an analysis of credit spreads (i.e., the spread in borrowing costs over Treasury yields) that indicates that bond investors require a higher credit spread premium when investing in OPG bonds.
>
> This phenomenon can be examined by comparing new issue credit spreads for indices of A-rated (i.e., for issuers with composite rating of A+, A, or A- ratings) to those of OPG. As shown in the figures below, OPG's credit spreads have remained consistently above the A-rated regulated utility credit spreads since January 2022. From January 1, 2022 to November 3, 2025, the average difference between OPG's credit spread and the A-rated Canadian utility average spread was approximately 20 basis points, with OPG demonstrating a wider spread over the entire period of analysis.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Please provide a table of the credit ratings for each of the six utilities (Hydro One Inc., Enbridge Gas Inc., EPCOR Utilities Inc., CU Inc., Toronto Hydro Corporation, and Alectra) contained in the analysis found in Figures 11 and 12.
b) Concentric: Please explain why none of the companies that appear in the proxy group for the capital structure analysis were included in the sample of utilities used in the comparison of bond spreads.

C1-Staff-51

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 52

Preamble:

Concentric stated the following:

> OPG also faces higher business risks due to severe weather and cyber-security than in 2016 or 2020, with weather events and cyber threats on the rise.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: How does severe weather affect hydroelectric power generation in Ontario?
b) Concentric: How does severe weather affect nuclear power generation in Ontario?

C1-Staff-52
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 61

Preamble:

Concentric stated the following:

> Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy

companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of that range.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: What determines whether an equity ratio is "appropriate"?

C1-Staff-53
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 63 & 66

Preamble:

Concentric stated the following:

> To develop the proxy group, Concentric conducted a series of screens based on OPG’s operating profile to refine all publicly-traded North American investor-owned utility companies to those with similar operating characteristics to OPG. To begin the screening process, Concentric began with all U.S. Electric Utilities, as categorized by Value Line, and publicly-traded Canadian utilities.

In Figure 15, Concentric provided its list of utilities included in its peer groups.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Why was it necessary to consider only publicly traded companies?
b) Concentric: Please explain why no government-owned utilities were included in any peer groups.

C1-Staff-54
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 63

Preamble:

Concentric stated the following:

> OPG's prescribed assets represent 100% rate-regulated generation, and companies in the proxy group should reflect the heighted risk profile of generating assets, especially as investors generally attribute higher risk to utilities with generation assets than those with only transmission or distribution operations. This is highlighted in Moody's 2024 ratings methodology for regulated electric and gas utilities: "[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Please provide the following for each utility included in the Main Peer Group using the most recently available data:
   i. The dollar value of nuclear generation plant-in-service
   ii. The dollar value of hydroelectric generation plant-in-service
   iii. The dollar value of total plant-in-service

C2-Staff-55

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

Preamble:

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

Question(s):

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

C2-Staff-56

Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 20
Ref 2: Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Ref 3: EB-2007-0905 Decision and Order / p. 88

Preamble:

OPG states that for the 2029-2031 period, the forecast of average unfunded nuclear liability is negative and has been set at $0 for the purposes of the revenue requirement calculation. As such, the full amount of the forecast average asset retirement cost (ARC) earns the proposed weighted average cost of capital.

The OEB-approved recovery methodology provides that return on rate base is calculated based on the lesser of the average unfunded nuclear liability and the average unamortized ARC.

In EB-2007-0905, the OEB adopted this approach to ensure that OPG does not earn its weighted average cost of capital on unfunded nuclear liabilities.

Question(s):

a) Please quantify, for each year from 2029-2031, the revenue requirement impact of applying the $0 unfunded nuclear liability floor compared to the calculated negative unfunded nuclear liability from Reference 2 in the return formula.
b) Please explain why the $0 floor remains appropriate in circumstances where Ontario Nuclear Funds Agreement (ONFA) funds exceed the accounting asset retirement obligation (ARO).
   i. Please confirm whether OPG has considered any alternative treatments for a negative unfunded nuclear liability, e.g. symmetrical adjustment or a sharing mechanism. If not, why not?
c) Please identify the primary drivers causing the unfunded nuclear liability to turn negative in 2029.
d) Based on current ONFA assumptions, is the negative unfunded nuclear liability expected to persist beyond 2031? Please provide a directional forecast.

C2-Staff-57

Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 30

Preamble:

OPG reviews and updates the Ontario Nuclear Funds Agreement (ONFA) Reference Plan and associated lifecycle cost estimates and assumptions at least every five years, in line with the ONFA requirements. An updated ONFA Reference Plan is submitted to the Province for review and approval. The next ONFA Reference Plan update, effective for the 2027-2031 period, is under development and is expected to be finalized in late 2026 for the Province's subsequent approval.

The proposed IR term nuclear revenue requirements reflect the approved 2022 ONFA Reference Plan. The corresponding impact of the approved 2027 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account for OPG's prescribed facilities and the Bruce Lease Net Revenues Variance Account for the Bruce facilities.

Question(s):

a) Please describe the key assumptions currently under review for the 2027 ONFA Reference Plan that could materially impact asset retirement obligation (ARO), Asset Retirement Costs (ARC), or unfunded nuclear liability (UNL) during the IR term.

b) Please confirm whether any portion of the forecast 2029-2031 negative UNL is sensitive to expected changes in the 2027 ONFA update.
c) Please describe the internal controls to ensure no duplication between Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account and the Pickering End-of-Life Deferral Account.

C2-Staff-58

Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 30
Ref 2: Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Ref 3: Exhibit C2 / Tab 1 / Schedule 1 / Table 3

Preamble:

OPG extended the accounting end of life (EOL) for Pickering Units 5-8 to 2070, resulting in an increase in prescribed asset retirement obligation (ARO) of $598.5 million and a decrease in the Bruce ARO of $438.7 million. The tables in Reference 2 and Reference 3 provide the revenue requirement impact of the extension.

Question(s):

a) Please provide a reconciliation of how the Pickering End of Life (EOL) extension affects the unfunded nuclear liability for prescribed facilities in 2027-2031.
b) Please confirm whether the allocation methodology for central nuclear programs has changed since EB-2020-0290. If so, describe the changes and their quantitative impact.

EXHIBIT D – CAPITAL PROJECTS

D1-Staff-59

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Table 1
Ref 2: Exhibit D2 / Tab 1 / Schedule 1 / p. 4
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1

Preamble:

At Reference 1, OPG lists the hydroelectric capital projects with a budget of over $30 million.

At Reference 2, OPG indicates that the Planning portion of its Investment Lifecycle involves asset health and condition assessments.

At Reference 3, some of the business case summaries for projects above $30 million include a summary of major assets subject to the proposed work including their age and condition.

Question(s):

a) Please explain the standards that inform OPG's asset condition assessments.
b) Please fill out the table below for all projects listed in Reference 1 that have a planned in-service date after January 1, 2027.

Table 1 – Asset Assessment

Project Name	Summary of Major Assets in Project Scope	Range of Remaining Useful Life of Major Assets	Condition of Major Assets at time of Project start

D1-Staff-60

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Table 1
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Chart 6
Ref 3: Exhibit F1 / Tab 1 / Schedule 1 / Chart 8

Preamble:

References 2 and 3 provide, respectively, station availability and equivalent forced outage rates for a selection of hydroelectric generating stations (GS). In Reference 1, there are three unit refurbishment projects identified at Alexander GS: Projects 82391, 86792, and 86793. Similarly, there is a refurbishment project at Manitou Falls GS: 86860. Neither of these two stations are part of the provided hydroelectric availability and equivalent forced outage rate tables.

Question(s):

a) Please provide the actual and target 2016 to 2024 hydroelectric availability for Alexander GS and Manitou Falls GS.
b) Please provide the actual and target 2016 to 2024 equivalent forced outage rate Alexander GS and Manitou Falls GS.
c) Please describe the trend in the historical EFOR and availability metrics for the units selected for the above projects as compared to the other units at the respective stations.

D1-Staff-61

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Table 1

Preamble:

OPG identifies which of the projects in Reference 1 are eligible for the Capacity Refurbishment Variance Account (CRVA).

Question(s):

a) Please list and explain the criteria OPG uses to determine that a project is eligible for CRVA treatment.
b) For each of the following projects, please explain how OPG determined them to be CRVA eligible:
   i. SAB1 Canal Isolation Preparedness Phase 1 (SAB1 CIP1)
   ii. Frederick House Lake Dam Upgrades
   iii. CHE - Limerick Isl. Spr Structure Sluice Gate Hoist
   iv. Surge Tank Replacement (at Silver Falls)
   v. Aguasabon Dam Rehab. Hayes Lake Main Dam

D1-Staff-62

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / p. 7

Preamble:

OPG stated that there are five Tier 1 projects for which total actual or forecasted project cost variances currently exceed 10% as compared to the total project cost estimate detailed in each project's first Execution business case.

Question(s):

a) Please identify the five projects. For each project, provide the total project budget at the First Execution Business Case Summary and the current project budget. Please provide a variance explanation.

D1-Staff-63

Ref 1: OPG Filing Requirements / p. 15

Preamble:

Reference 1 states that OPG should provide variance explanations for certain capital projects over $30 million with respect to OEB-approved vs. actual for each of the Historic Years, and OEB-approved vs. Bridge Year forecast.

Question(s):

a) Please file a summary table and variance explanations similar to that described at Reference 1 that lists the hydroelectric projects that were approved as part of OPG’s Business Plan and planned to go into service in the 2022 to 2026 period and the actual in-service additions during that period.

D1-Staff-64

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Tables 5a and 5b
Ref 2: Exhibit D1 / Tab 1 / Schedule 1 / Table 2
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Table 4

Preamble:

Reference 1 lists 78 unallocated projects greater than $10 million.

At References 2 and 3, OPG shows the capital expenditures summary and capital in-service additions, broken down according to allocated and unallocated projects.

Question(s):

a) Most of the projects listed in Reference 1 appear to show a Potential Start Date in the year 1905.
   i. Please provide updated tables with the corrected potential start dates.
   ii. Please provide the potential in-service year, if the project were to proceed as per the potential start date.
   iii. Please provide the estimated total cost for each of these projects. Please explain if these costs do not reconcile to Reference 2.

D1-Staff-65

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / p. 17
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / p. 6
Ref 3: Exhibit D2 / Tab 4 / Schedule 3 / pp. 3-16

Preamble:

References 1 and 2 identify the Renewable Generation Programmatic Collaboration Agreement (RG PCA) relating to hydroelectric refurbishments. OEB staff is unable to locate the details of the PCA in the evidence.

Question(s):

a) Please describe the RG PCA at a level commensurate with OPG's summary of the DNNP Integrated Project Agreement at Reference 3.

D1-Staff-66

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / p. 23

Preamble:

At Reference 1, OPG states that for Project #82543 Otter Rapids GS G2 Refurbishment, the initial estimate in the Partial Execution Business Case Summary (BCS) was $43.1 million. The subsequent Full Execution BCS included an estimate of $51.8 million. OPG now anticipates the total project cost to be $78.1 million, an increase of $26.2 million from the Full Execution BCS. The cost variance relative to the Full Execution BCS is driven by issues discovered after project execution had begun which required "additional welding and grinding to resolve the cracks, as well as the installation of backing material to fill the transition gaps."

Question(s):

a) Please provide the Partial Execution BCS for the Otter Rapids GS G2 Refurbishment, including any project risk assessment documentation at the time of its approval.
b) Has OPG encountered similar issues regarding the cracks and transition gaps in previous projects?
   i. How much did those issues cost to resolve? Please provide specific project examples.
c) Please explain the relationship between the "Otter camp and road" costs in the unit overhaul project and the Otter Project Camp (Project # 84907).

D1-Staff-67

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / pp. 24-25

Preamble:

At Reference 1, OPG states that Project #83495 R.H. Saunders GS G9 Capital Refurbishment enables sustaining 64.6 MW of existing generating capacity. The total project cost is estimated to be $42.7 million. This represents an increase of $25.5 million from the Class 4 Estimate of $17.2 million provided in the first Partial Execution Business Case Summary (BCS). The Full Execution BCS detailed a Class 3 Estimate of $24.8 million, which is a $17.9 million cost variance from the total project cost.

Question(s):

a) Please provide a detailed monetary breakdown of the variance between the $17.9 million Full Execution BCS estimate cost variance and the total project cost.

D1-Staff-68

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Table 1

Preamble:

At Reference 1, OPG lists three refurbishment projects at Saunders GS: G9, G12, and G16. The Total Project Costs for the three projects range from $30.4 million (G12) to $49.3 million (G16).

Question(s):

a) Please explain the difference in cost and in the project scope between SAU - G12 Capital Refurbishment, SAU - G16 Capital Refurbishment, and SAU - G9 Capital Refurbishment

D1-Staff-69

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / pp. 10-11

Preamble:

At Reference 1, OPG states that projects #86595 R.H. Saunders GS: Long Sault Dam Capital Program and #87142 R.H. Saunders GS: Massena Canal Dam are managed by the New York Power Authority, with OPG sharing equally in the costs required to operate and maintain assets within the St. Lawrence River management system.

Question(s):

a) How does OPG assess the need and prudence of costs of projects managed by the New York Power Authority, like the ones discussed in the preamble? Please provide any analysis conducted to that end for the projects discussed in the preamble.

b) Does OPG have any input into any key decisions for projects like the ones discussed in the preamble? Please explain.

D1-Staff-70

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 32 / 86937 / p. 5

Preamble:

At Reference 1, OPG states under Alternative 3 that in order to maximize the benefits of the Saunders overhauls, the Pre-Overhaul Condition Assessment recommended completing slot cutting to relieve internal stresses caused by Alkali-Aggregate Reaction. This recommendation was accepted and executed through a project SAU83086 from 2017-2019. OPG stated that delaying the start of the overhauls would diminish the added benefits the concrete slot cutting will provide to the Saunders overhauls.

Question(s):

a) Please provide the Final Execution Business Case Summary (BCS) for the slot cutting project (SAU83086)
b) Please elaborate on how delaying the Saunders overhauls would diminish SAU83086's benefits.

D1-Staff-71

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / pp. 28-29
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 6 / 82089 / p. 7

Preamble:

At Reference 1, OPG states that through the Project #82089 Calabogie GS Redevelopment, the original powerhouse and intake structure were demolished, and the existing forebay concrete was remediated.

This project was completed at a total cost of $167.2 million, which is an increase of $30.7 million from the Class 3 estimate of $136.5 million detailed in the first Execution Business Case Summary (BCS).

At Reference 2, OPG states that Procurement was 31% of the total costs.

Question(s):

a) Please provide a detailed monetary breakdown of the variance between the $30.7 million First Execution BCS estimate and the total project cost.
b) Please explain why procurement is such a large percentage of total costs relative to other projects. Please provide a breakdown of procurement costs.

D1-Staff-72

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 35 / 87217 / p. 2

Preamble:

At Reference 1, OPG states that for Project #87217 Aguasabon Dam Rehabilitation: Hayes Lake Main Dam, the preferred alternative is the rehabilitation of concrete including the integrity of handrail anchors.

Question(s):

a) What is the current phase of this project? What is the most up to date estimate for this project?
b) Has OPG considered any other alternatives? If no, please explain. If yes, please provide a summary.

D1-Staff-73

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 41 / 87768
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 38 / 87357
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 37 / 87356
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 23 / 86372
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 26 / 86570
Ref 6: Exhibit H1 / Tab 1 / Schedule 1 / pp. 60-63

Preamble:

References 1-5 are the business case summaries for five refurbishment projects at the Sir Adam Beck facilities. Within the business case summaries, OPG states that the projects will upgrade equipment to meet current regulatory requirements and eliminate known safety hazards.

Reference 6 describes OPG's proposed Change in Laws Deferral Account, which would record material impacts due to changes in legal and regulatory requirements.

Question(s):

a) For these projects, please describe the regulatory requirements, the related equipment that is non-compliant, and the nature of the non-compliance.
b) Please explain how the work described in References 1-5 relates to the proposed deferral account. Please explain the degree to which OPG's proposed deferral account would or could apply to these projects.

D1-Staff-74

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 41 / 87768 / pp. 3-4
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 26 / 86570 / p. 2

Preamble:

Reference 1 is the business case summary for the Sir Adam Beck 2 G19/20 refurbishment project. OPG states that upfront costs common to the Sir Adam Beck 2 refurbishments were included in the G19/20 project scope.

Reference 2 is the business case summary for the Sir Adam Beck 1 G4 refurbishment project. OPG states that upfront costs common to the Sir Adam Beck 1 refurbishments were included in the G4 project scope.

Question(s):

a) Please provide a breakdown of the upfront costs within the G19/20 project that are common to the Sir Adam Beck 2 refurbishments.
b) Please provide a breakdown of the upfront costs within the G4 project that are common to the Sir Adam Beck 1 refurbishments.

D1-Staff-75

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 42 / 89252 / pp. 3-5

Preamble:

At Reference 1, OPG states that the canal rehabilitation project began under Project 82771, which funded condition assessments and various project management activities, including the development of an initial overall cost estimate and technical specification. The project was deferred in 2020 following a risk analysis that confirmed that the canal conditions could sustain this delay. As per the plan upon project deferral, a team was reassembled to explore restarting the project in 2024.

Under Alternative 2, OPG states that not proceeding with the project does not allow for proactive efforts required to ensure the ability to be able to isolate/dewater the canal in support of MTO Hwy 420 culvert repairs.

Question(s):

a) How long did the 2020 risk analysis indicate the canal could sustain a delay in rehabilitation? Have any more recent risk analyses been performed? If yes, how long did they indicate a delay could be sustained?
b) Please confirm if OPG can meet the needs of the MTO Hwy 420 culvert repairs without the rehabilitation of the canal. If it can’t, please explain.

D1-Staff-76

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 5 / 82087 / pp. 3-8

Preamble:

Reference 1 relates to the Coniston and Stinson GS Redevelopment Project. OPG states that analysis shows that the redevelopments will provide positive economic value to the province’s electricity system.

Question(s):

a) Has OPG performed a net-present value (NPV) assessment or analysis for this project? If yes, please provide it. Please summarize the NPV of this project. If no assessment or analysis has been done, please explain why not.

D1-Staff-77

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 25 / 86387 / pp. 2-4

Preamble:

At Reference 1, OPG describes the project to redevelop Matabitchuan GS. OPG states that the Matabitchuan GS is 115 years old and operates with the original turbine and generator units, which have been maintained through various overhauls.

OPG states that among other things the preferred alternative includes the replacement of the lower bifurcated penstock section and replacement of the Bailey bridge.

OPG states that the penstock section from the headworks to the powerhouse bifurcation was replaced in 2012, as was the headgates and hoist.

Question(s):

a) Why does the preferred alternative also include replacing the lower bifurcated penstock section since it was done in 2012?
   i. What is the condition and estimated remaining useful life of the penstock section?
   ii. What was the cost of the replacement of the penstock section in 2012?
b) What is the condition and remaining useful life of the Bailey bridge and why does it need to be replaced?

D1-Staff-78

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 1 / 80581 / p. 15

Preamble:

At Reference 1, OPG shows that the total project estimate at the Definition Phase for the Ranney Falls GS Expansion was $48.7 million, and at the Full Release Execution Phase was $71.2 million.

Question(s):

a) Please confirm whether the Definition Phase Business Case Summary (BCS) estimated the total project cost to be $48.7 million and that with the Execution Phase, the project has a new total project cost estimate of $71.2 million. If not confirmed, please explain.
b) Please provide a breakdown of the variance between the Definition Phase and Full Release Execution Phase estimates.

D1-Staff-79

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / p. 43
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 34 / 87197 / p.2

Preamble:

At Reference 1, OPG describes the Timmins Building Expansion project. OPG states the project will renovate and expand the Timmins Service Centre at a total estimated project cost of $35.1 million.

At Reference 2, OPG states that some alternatives have been reviewed at a high level, including relocation of staff to a different location, building a new building on property, and expansion to the existing facility. OPG states that a more detailed review of these and other available options / alternatives will be completed as part of the definition business case summary (BCS).

Question(s):

a) How many more staff does OPG anticipate to be added to the Timmins Service Centre within the forecast period?
b) Please provide an updated estimate of the total project cost. Please confirm whether Reference 2 is the most recently approved BCS. If not confirmed please provide the most recently approved BCS for the Timmins Building Expansion Project most recently approved BCS.

D1-Staff-80

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / pp. 43-44

Preamble:

As per Reference 1, OPG states the objective of Project #87329 Dymond Machine Shop is to expand OPG's Dymond Machine Shop, which provides machining, fabrication, and welding services to the Renewable Generation facilities. OPG states the project is necessary to prepare the Dymond Machine Shop for supporting OPG's turbine-generator overhaul and refurbishment programs and reduce the risk of schedule delays due to reliance on original equipment manufacturers (OEMs) and external machining shops.

Question(s):

a) Please provide the current total project cost estimate. If there is a more recent business case summary (BCS) than the one filed, please provide it.
b) Please confirm that after this project is complete, OPG will then procure the new equipment for the machine shop.
c) Please confirm the start date (or year) of the 20-year unit overhaul/refurbishment program referenced in the BCS.

D2-Staff-81

Ref 1: OPG_Working_Excel_Table D_Cap_Proj_20251219 / Tab D2-1-3 Table 1a to 2g & Tables 5a to 5d

Preamble:

At Reference 1, OPG identifies which of the OPG nuclear facilities projects are eligible for the Capacity Refurbishment Variance Account (CRVA).

Question(s):

a) Please list and explain the criteria OPG uses to determine whether a nuclear project is eligible for CRVA treatment.
b) Referencing the criteria from part a), please explain the basis upon which OPG has assessed the Tritium Removal Facility Major Component Replacement Program as CRVA eligible.

D2-Staff-82

Ref 1: Exhibit D2 / Tab 1 / Schedule 2 & 3

Preamble:

At Reference 1, OPG proposes multiple major capital initiatives at Darlington during the 2027–2031 period, including but not limited to turbine rotor replacements, steam generator chemical cleaning, primary moisture separator replacements, turbine control upgrades, Tritium Removal Facility (TRF) major component replacement, and other outage-dependent work scopes.

Several of these projects are scheduled during planned outages and are identified as having potential outage critical path interactions.

Question(s):

a) Please provide a consolidated outage schedule for Darlington Units 1–4 for the 2027–2031 period identifying, by unit and outage, all major capital work scopes proposed to be executed, including estimated outage duration impacts attributable to each scope.
b) Please identify any outages during the IR term in which more than one Tier 1 capital project (over $30 million) is scheduled concurrently and describe:
   i. The combined critical path duration
   ii. Schedule contingency incorporated
   iii. The quantified risk of outage extension to the extent possible
c) Please explain how cumulative schedule risk across these projects has been assessed, including whether integrated schedule risk modelling (e.g., Monte Carlo or equivalent probabilistic analysis) has been performed.

D2-Staff-83

Ref 1: Exhibit D2 / Tab 1 / Schedule 2 & 3

Preamble:

Nuclear capital operations Tier 1 projects (over $30 million total project cost) in the 2027–2031 period are at varying Business Case Summary Gate phases (e.g., Development, Definition, partial Definition releases). OPG's Gate process is intended to progressively refine scope and cost estimates as projects mature.

Question(s):

a) For each nuclear Tier 1 project included in the 2027–2031 forecast, please provide in a tabular format:
   i. The current Gate phase
   ii. The estimate class (e.g., AACE Class 5–3) associated with the current total project cost
   iii. The expected accuracy range for that estimate class
b) For nuclear operations capital Tier 1 projects completed historically, please provide:
   i. The Gate phase and estimate class at the time of Execution phase approval
   ii. The final actual project cost
   iii. The variance of the actual project cost relative to the execution phase estimate, and whether that variance fell within the expected accuracy range.
c) Please comment on how the Gate phase and estimate maturity of the 2027–2031 Tier 1 projects support the reasonableness of the forecast in-service amounts included in this application.

D2-Staff-84

Ref 1: Exhibit D2 / Tab 1 / Schedule 3

Preamble:

Reference 1 describes how certain capital projects (e.g., turbine rotor replacements and related upgrades) are expected to increase generating output and/or reduce forced loss rate.

Question(s):

a) Please confirm whether projected output improvements and forced loss rate reductions associated with capital projects in the 2027–2031 period are reflected in forecast production and revenue assumptions.
b) If so, quantify the incremental MWh assumed in each year attributable to these projects.
c) If not, explain how the incremental generation output is reflected in the revenue requirement framework.

D2-Staff-85

Ref 1: Exhibit D2 / Tab 1 / Schedule 3

Preamble:

Several nuclear projects cite supply chain constraints, vendor capacity limitations, or long lead times as factors influencing the timing of the projects.

Question(s):

a) Please identify all nuclear projects in the IR term for which project timing has been advanced or early procurement commitments have been made in order to mitigate supply chain constraints (e.g., long lead manufacturing slots), rather than due to immediate technical necessity.
b) For the projects identified in (a), please provide the analysis performed to evaluate the trade-off between advancing procurement/project versus deferring the work, including any estimate of cost escalation risk associated with deferral by three and five years.
c) Confirm whether any long lead procurement commitments have been made prior to Execution Phase (Gate 3) approval. If so, describe associated cancellation or stranded procurement risks.

D2-Staff-86

Ref 1: Exhibit D2 / Tab 1 / Schedule 3

Preamble:

Multiple capital projects in the 2027–2031 period identify reliability improvements, forced loss rate (FLR) reductions, and maintenance optimization as expected outcomes.

Question(s):

a) Please describe how OPG has assessed and aggregated project FLR reductions from individual nuclear capital projects over the IR term, including the total expected fleet-level FLR reduction and how potential overlap among project-level benefit estimates was addressed to avoid any double counting.
b) Please quantify the expected incremental energy production (MWh) associated with the FLR reductions in part a), by year (2027-2031), and confirm whether these MWh impacts are reflected in OPG's forecast energy production for the IR term. If not, please explain how the benefits are reflected in the application.

D2-Staff-87

Ref 1: OPG_Working_Excel_Table D_Cap_Proj_20251219 / Tab D2-1-3 Table 1a
Ref 2: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 26 (Project #83664 BCS)
Ref 3: Exhibit D2 / Tab 1 / Schedule 2 / Term-over-Term Changes – Nuclear Operations, pp. 10-24
Ref 4: Exhibit D2 / Tab 1 / Schedule 1 / pp.4-5

Preamble:

At Reference 1 in line number 27, OPG states that the total project cost per EB-2020-0290 for Project #83664 was $112.7 million. At Reference 2, OPG provides an updated total project cost estimate of approximately $194.6 million, with a completion date in June 2028.

At Reference 3, OPG identifies Project #83664 as a significant contributor to the increase in Nuclear Operations non-portfolio in-service additions during the 2027–2031 period.

OPG has further stated that turbine control and auxiliary system replacements were completed on Darlington Units 1, 3, and 4 through the DRP, but that installation on Unit 2 was excluded from the Unit 2 DRP scope because the existing control system had useful remaining life and to mitigate first-of-a-kind risk (FOAK), given that Unit 2 was the first unit refurbished.

At Reference 4, OPG states that "OPG's current asset management and investment planning process overseen by the asset management governing body consists of the following three steps", one of which is "investment assessment".

Question(s):

a) Please reconcile the previous total project cost estimate of $112.7 million from EB-2020-0290 with the updated total project cost estimate of approximately $194.6 million. The explanation should clearly break down the cost increase and attribute the variance, to the extent possible, to specific drivers such as:
   - Scope changes (what was added, removed, or modified)
   - Schedule deferral, including the impact of shifting the in-service date from the D2421 outage to the D2721 outage
   - Contingency adjustments or risk-based revisions
   - Any other material cost drivers

   The response should quantify each driver to the extent feasible and describe how each contributed to the overall increase.

b) Please provide all decision documentation approving the deferral of this work from the Unit 2 refurbishment scope due to FOAK risks. If such documentation does not exist, then please explain why.

c) Please provide a copy of the "investment assessment" document that would have been carried out for this project as per OPG's asset management and investment planning process. If no investment assessment was carried out, explain why. Was lifecycle-cost comparison (e.g., evaluating completion during refurbishment versus deferral) considered as a part of that investment assessment? If not, please explain why not.

D2-Staff-88

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 26 (Project #83664 BCS)

Preamble:

At Reference 1, OPG states that:

> "Preliminary research completed using Electric Power Research Institute (EPRI) guidelines has found that Printed Circuit Boards (PCB) used in the nuclear industry have a reliable lifespan of approximately 10 to 15 years; the cards at DNGS are over 20 years old and are approaching the end of life. Recent card failures, which were documented in numerous SCRs by both Maintenance and Performance Engineering, are considered to be precursors of higher card failure rates that occur towards the end of equipment life. OPEX from other nuclear stations in Canada and US show the turbine and generator control systems were replaced after approximately 20 years of service."

Question(s):

a) Please provide the following evidence supporting the conclusion that PCB aging at Darlington Nuclear Generating Station (DNGS) warrants the proposed scope and timing of replacement:
   i. A summary of the EPRI guidelines relied upon, including the specific references and recommended life-expectancy criteria.
   ii. A quantitative summary of the card failures that are described in Reference 1 over the past 10 years (e.g., number per year, failure modes, trend).

b) Please provide details on operating experience (OPEX) "from other nuclear stations in Canada and US" that OPG refers to in Reference 1.

c) Please provide a comparison of DNGS operating conditions to the OPEX examples cited (Canada/US), and an explanation of how these analogues support OPG's replacement timing.

d) Please explain whether alternative approaches (e.g., targeted replacement, enhanced testing, selective life-extension measures) were assessed and why full-scope replacement is the prudent option. If they were considered, please provide the detailed analysis. If not, please explain why.

e) Please confirm whether any interim mitigation measures or enhanced maintenance activities were required between Unit 2's return to service in 2020 and the planned 2027 upgrade to maintain reliability of the existing control system, and if so, quantify the associated costs.

D2-Staff-89

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / TRF Major Component Replacement Program, p. 18

Preamble:

At Reference 1, OPG includes a new non-portfolio project titled "Tritium Removal Facility Major Component Replacement Program" with forecast in-service amount of $452.0 million with $157.6 million over the 2027–2031 period. OPG states that the Tritium Removal Facility (TRF) will reach the end of its expected service life in 2025, that annual throughput (Mg D_2O processed) has shown a continued decline in performance, and that delaying refurbishment is not a viable alternative.

OPG's capital schedule indicates that spending on this project commenced in 2024.

The TRF Major Component Replacement Program was not identified as a discrete project in EB-2020-0290.

Question(s):

a) Please explain why the need for major component replacement at the TRF, with an expected end-of-life in 2025, was not identified in EB-2020-0290. Confirm whether, at the time of EB-2020-0290, OPG had identified degradation trends or remaining useful life concerns for the TRF. If so, explain why a major component replacement program was not included in that application.
b) Please clarify the extent to which the TRF Major Component Replacement Program was, at any time, part of the Darlington Refurbishment Program scope and $12.8 billion Darlington Refurbishment Program budget. If it was not part of the program scope at any time, please explain why.
c) Provide the year in which OPG first determined that the TRF would reach the end of its expected service life in 2025 and describe the analysis supporting that determination.
d) Provide internal asset management or capital planning documentation from 2018–2022 indicating when this project first entered OPG's long-term capital forecast.
e) Provide the original design life of the TRF (in years and cumulative Mg D_2O processed), the cumulative throughput to date, and the percentage of design life consumed. In addition, provide annual throughput for the past 15 years compared to nameplate capacity and quantify the observed decline in performance and its technical causes.

f) Identify the specific components being replaced and confirm whether the project constitutes lifecycle replacement of end-of-life assets, failure-driven replacement, or performance enhancement beyond original design capability.
g) OPG states that delaying refurbishment is not a viable alternative. Please quantify the operational risks and regulatory risks, to the extent possible, associated with deferral and provide any supporting risk assessment or engineering studies, including the maximum deferral period evaluated.

D2-Staff-90

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Darlington Steam Generator Primary Moisture Separators Replacement Projects, pp. 13–15
Ref 2: Exhibit D2 / Tab 1 / Schedule 2 / Section 3 Capital Expenditures p. 5

Preamble:

At Reference 1, OPG states that inspections during Darlington Unit 3 refurbishment identified deterioration of the primary moisture separators due to flow-assisted corrosion. OPG subsequently expanded inspections to other units and determined that replacement of all primary moisture separators across the four Darlington units was required.

Project #86693 has a total estimated cost of $359.2 million and Project #87151 has a total estimated cost of $275.0 million. OPG indicates that replacement of these components was not part of the Darlington Refurbishment Program (DRP) scope.

Further at Reference 2, OPG states that the need for this project arose from the detailed inspections conducted during the DRP of components not typically accessible during regular planned outages.

Question(s):

a) Please confirm whether OPG was unable to conduct inspections of the primary moisture separators prior to the DRP and was therefore not aware of their condition. If this is not the case, please provide historical inspection and condition assessment results for the primary moisture separators for each Darlington unit for the past 10 years. Indicate when flow-assisted corrosion was first identified and how the condition trended over time.

b) Please clarify the extent to which primary moisture separator replacements at units 1 through 4 were, at any time, part of the DRP scope and $12.8 billion DRP budget. If the primary moisture separator replacements were not part of the program scope at any time, please explain why.
c) Provide the engineering assessment and risk analysis that supported the decision to replace all primary moisture separators across all four units rather than pursuing targeted replacement or enhanced monitoring.
d) Explain whether executing work outside of the original refurbishment outage windows resulted in incremental costs. If so, quantify those incremental costs.
e) Identify any changes to scope, schedule, or cost since the projects were first approved internally, and explain the drivers of those changes.

D2-Staff-91

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 45

Preamble:

At Reference 1, OPG states that Project #86910 will replace approximately 14,000 fluorescent lighting fixtures with LED lighting at Darlington at a total project cost of approximately $39.9 million. OPG indicates that annual lighting maintenance costs exceed $1.3 million and identifies a target to reduce annual maintenance costs and energy consumption by 50%.

Question(s):

a) Please confirm whether the stated annual lighting maintenance cost of approximately $1.3 million relates solely to the approximately 14,000 fixtures within the scope of this project.
b) If available, please provide the economic evaluation supporting the project and any sensitivity analysis performed on LED life and failure assumptions.
c) Please explain whether OPG evaluated phased replacement through normal maintenance cycles instead of a concentrated capital program and provide the results of any such evaluation.

D2-Staff-92

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Table 1c
Ref 2: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 51

Preamble:

At Reference 1, OPG presents Project #89281 with a total project cost of approximately $350 million and forecast in-service amounts during the IR term. However, at Reference 2, the Business Case Summary (BCS) identifies the total project cost as "TBD."

Question(s):

a) Please clarify the extent to which stator rewind for units 1 through 4 were, at any time, part of the Darlington Refurbishment Program (DRP) scope and $12.8 billion DRP Program budget. If they were not part of the program scope at any time, please explain why.
b) Please reconcile the approximately $350 million total project cost presented in the D2 tables with the "TBD" total project cost shown in the BCS. What is the current approved total project cost for this project?
c) Please identify:
   i. The estimate class associated with the approximately $350 million figure
   ii. The confidence range for that estimate
   iii. The current BCS phase, including whether First Execution BCS approval has been obtained.
d) Please provide a latest BCS if available.

D2-Staff-93

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 49

Preamble:

At Reference 1, OPG states that stress corrosion cracking has been detected in low-pressure (LP) rotors of all Darlington units and that engineering projections indicate rotor replacement will be required prior to station end of life. OPG also states that advancement of LP replacements is not technically necessary based on crack projections but is being pursued to mitigate supply chain and manufacturing risks. The preferred alternative includes replacement of both LP and high-pressure (HP) turbines and acquisition of a spare LP rotor.

Question(s):

a) Please clarify the extent to which the Darlington Turbine Rotors Replacement was, at any time, part of the Darlington Refurbishment Program (DRP) scope and $12.8 billion DRP budget. If it was not part of the program scope at any time, please explain why.
b) Please provide the projected year in which each LP rotor would reach critical crack depth based on current crack growth models and quantify the safety margin remaining relative to the planned replacement outages.
c) Given that advancement of LP replacements is stated to be not technically necessary, please quantify to the extent possible:
    i. The expected cost impact of deferring procurement by five years to the next IR term 2032-2036.
    ii. The probability-weighted schedule delay risk associated with not securing original equipment manufacturing slots at this time.
d) For the HP turbines, please provide:
    i. The incremental capital cost attributable to inclusion of HP turbine replacement.
    ii. The standalone economic analysis supporting HP replacement (including net present value (NPV) and assumptions underlying the ~$70/MWh levelized cost of energy (LCOE) estimate).
    iii. Confirmation of whether the incremental 21.6 MWe per unit is reflected in forecast production or revenue assumptions.
e) Please provide a summary of any internal trending or engineering reports relating to the turbine rotors that were presented at any engineering or site management meetings from the 2017 to 2025.

D2-Staff-94

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 52

Preamble:

At Reference 1, OPG proposes a full secondary side chemical cleaning of Darlington steam generators at an estimated total project cost of $77.9 million (range $60 million–

$90 million), including a pilot in Unit 3 prior to full implementation. OPG states that sludge and deposits have accumulated despite routine water lancing and that cleaning is required to preserve long-term fitness-for-service.

Question(s):

a) Please clarify the extent to which Darlington Steam Generator Soft Chemical Cleaning project was, at any time, part of the Darlington Refurbishment Program (DRP) scope and $12.8 billion DRP budget. If it was not part of the program scope at any time, please explain why.
b) Please quantify the current extent of sludge and deposit accumulation for each unit and provide the projected year at which fitness-for-service limits would be approached without chemical cleaning.
c) Provide the historical trend in deposit accumulation and explain, with quantitative support, why continued water lancing is insufficient to maintain long-term performance.
d) Provide the anticipated corrosion allowance and expected material loss associated with the soft chemical cleaning process and identify any benchmarking from comparable units demonstrating long-term integrity impacts.
e) What improvement to the level of estimate accuracy does OPG expect the Unit 3 pilot will provide?

D2-Staff-95

Ref 1: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1 / Tab 50

Preamble:

At Reference 1, OPG proposes installation of 37 sensor integration scope elements at Darlington at an estimated total cost of $51.0 million (range $38 million–$58 million) to support equipment reliability improvements, transition to condition-based maintenance, and optimization of manual rounds. The project includes pilot installations and does not identify Post-Implementation Review Key Performance Indicators (PIR KPI).

Question(s):

a) Please quantify the baseline and projected reduction associated with this project for: Forced Loss Rate (FLR), annual maintenance labour hours, and manual operator round hours. Please identify which of these reductions are expected to result in measurable cost savings versus redeployment of resources.
b) The project includes pilot installations covering approximately 7% of scope. Please explain how pilot results will refine total project cost and scope and identify the potential variance in total project cost following pilot completion.
c) Given that no PIR KPI has been identified, please explain how OPG will measure and validate realization of the projected reliability and maintenance benefits.

D2-Staff-96

Ref 1: Exhibit D2 / Tab 3 / Schedule 1 / pp. 3-4
Ref 2: Exhibit F4 / Tab 1 / Schedule 1 / pp. 16-17

Preamble:

At Reference 1, OPG states that the Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) total $26.84 billion, inclusive of contingency, interest and escalation, and as approved by OPG's Board of Directors in November 2025.

The RQE includes $4.05 billion of interest.

At Reference 2, OPG states that for Pickering Units 5-8 OPG implemented a change to extend the accounting end-of-life date assumption for Pickering Units 5-8 to December 31, 2070, effective December 31, 2023, based on the expectation of their refurbishment.

Question(s):

a) Please confirm whether the extension of the accounting end-of-life date for the PRP to 2070 has resulted in any change to the:
   i. PRP Scope;
   ii. The RQE total capital cost estimate;
   iii. The PRP capital expenditure timing for 2027-2031
   iv. If yes to any of i-iii above, please provide a quantitative bridge by year showing the impact of the end-of-life extension. If no, explain why no revision was required.

b) Please confirm whether the RQE and 2027-2031 capital forecast were developed on the basis that:
    i. Operation of refurbished Units 5-8 would extend to 2070; and,
    ii. All life-extension assumptions embedded in depreciation, asset life and nuclear liability modeling are fully aligned with the PRP capital forecast
c) Please confirm whether the $4.05 billion of interest assumes capitalization of any interest on CWIP or if the entirety is assumed as recovery under the concurrent cost recovery (CCR) framework:
    i. Please confirm that no interest amounts are embedded in the RQE as capitalized interest and are also recovered through CCR.
d) Please provide a confirmation that CCR did not alter the total PRP program cost or capital forecast introduced in this application.

D2-Staff-97

Ref 1: Exhibit D2 / Tab 3 / Schedule 3 / p. 8

Preamble:

At Reference 1, OPG states "the Class 3 Definition phase, encompassing the majority of high-value items such as reactor components, boilers, and specialized tooling, was thoroughly evaluated using both industry and DRP RFR Project benchmarks".

Question(s):

a) Please provide a summary comparison of the Pickering Refurbishment Program (PRP) with the industry and Darlington Refurbishment Program Retube and Feeder Replacement (DRP RFR) project benchmarks that are referenced in the preamble.
b) If the PRP benchmarking comparison was approved by the OPG board, please provide materials that were approved.

D2-Staff-98

Ref 1: Exhibit D2 / Tab 3 / Schedule 3 / p. 11
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / Chart 3

Preamble:

At Reference 1, OPG states that “where the contractor has less impact on outcomes, OPG has excluded the work from the target pricing structure. Instead, cost plus mark-up pricing is used for Owner Specified Materials as well as for commissioning work.”

Reference 2 summarizes the Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) according to 11 cost categories.

Question(s):

a) Please provide the dollar amount of Owner Specified Materials and commissioning work according to the 11 PRP RQE cost categories as applicable.
b) Please describe how OPG validated the costs of Owner Specified Materials and commissioning work.
c) Please provide the dollar amount of Owner Specified Materials and commissioning work that is included in the total 2023-2031 PRP in-service addition of $9,868 million.

D2-Staff-99

Ref 1: Exhibit D2 / Tab 3 / Schedule 4 / p. 7

Preamble:

At Reference 1, “A key difference between the PRP and DRP is that PRP will begin with the full station being offline and all four units being refurbished in parallel, creating larger resourcing demands and greater complexity in execution”.

Question(s):

a) Please explain why OPG decided to refurbish all units in parallel instead of in sequence like in the Darlington Refurbishment Program (DRP).
b) Did OPG present an analysis of alternative approaches (e.g., refurbishment in parallel, refurbishment in series) and a recommendation to its Board of Directors for approval? If so, please provide the analysis and approval. If not, why not?

c) Please describe the cost implications of OPG's choice to refurbish all units in parallel instead of in sequence like in the DRP. For example, does the refurbishment of all units in parallel increase or decrease costs compared to other alternatives that OPG considered. If so, by how much do costs increase or decrease?

D2-Staff-100

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / p. 6

Preamble:

At Reference 1, OPG states that the Pickering Refurbishment Program (PRP) "overall Class 3 estimate was based on a bottom-up estimating methodology."

Question(s):

a) How does the estimating methodology that OPG used for the PRP compare to the estimating methodology that it used for the Darlington Refurbishment Program (DRP)? If there are key differences, please explain what they are why.

D2-Staff-101

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Chart 3

Preamble:

Reference 1 summarizes the Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) according to 11 cost categories.

Question(s):

a) Please provide a table which compares the cost and percentage of each bundle/category in chart 3 with the corresponding cost and percentage of the Darlington Refurbishment Program (DRP) RQE (or actual DRP cost, if more convenient). Please explain key differences between the PRP and DRP costs and percentages.

D2-Staff-102

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / pp. 11-16
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / Charts 6 - 11

Preamble:

At Reference 1, OPG states that it conducted benchmarking exercises to “challenge and validate the estimate for” the each of the major work bundles (Retube, Feeder and Boiler Replacement, Turbine Generator, Balance of Plant, Operations and Maintenance, Facilities and Infrastructure, and Deep Water Intake).

At Reference 2, OPG provides a cost breakdown of Unit 5 major work bundle costs which are part of the total forecast Unit 5 in-service amount.

Question(s):

a) Please provide OPG’s benchmarking findings for each of the Unit 5 major work bundle costs.

D2-Staff-103

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Charts 6 – 11
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / p.10
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / Chart 5

Preamble:

At Reference 1, OPG provides a cost breakdown of five Unit 5 major work bundle costs which are part of the total forecast Unit 5 in-service amount. The costs of the five major work bundles presented in charts 6 - 11 total $7,360 million.

At Reference 2, OPG states “the total capital cost of the Major Work Bundles is $7,244.7 million”.

At Reference 2, OPG also states that “as illustrated in Chart 5 above, the Major Work Bundles account for 62% of the total Unit 5 refurbishment capital cost estimate (including common costs)”.

At Reference 3, OPG presents chart 5, which is a breakdown of the 2026-2031 PRP In-Service Additions. The total in chart 5 is $9,868 million, the major work bundles are stated to account for 73% of the total shown.

Question(s):

a) Please clarify the difference between the total major work bundle costs presented between references 1 and 2 ($7,360 million vs. $7,244.7 million).
b) Please clarify the difference between the major work bundle shares presented between references 2 and 3 (62% vs. 73%).

D2-Staff-104

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Charts 6 – 11

Preamble:

At Reference 1, OPG provides a cost breakdown of five Unit 5 major work bundle costs which are part of the total forecast Unit 5 in-service amount. The cost of the project management category across the five major work bundles appears to total $1,708 million out of a total $7,360 million. The total project management cost appears to represent approximately 23% of the total cost of the five Unit 5 major work bundles.

Question(s):

a) Please confirm the total project management cost and percentage share across the five Unit 5 major work bundle costs which are part of the total forecast Unit 5 in-service amount.
b) What is the project management cost and percentage share in the $26.8 billion Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE)?
c) How does the PRP RQE project management cost compare to the project management cost of the Darlington Refurbishment Program (DRP) RQE and Darlington New Nuclear Program (DNNP) RQE? Please explain key differences.

D2-Staff-105

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / p.18

Preamble:

At Reference 1, OPG states “the total in-service amounts for the F&I projects are $159.3 million in the bridge year, 2026, and $20.6 million in 2027 during the IR term.”

Reference 1 specifies the total project costs of the following projects that will be in-service in 2026: Common Services Building ($57.4 million), Pickering Maintenance Facility ($30.7 million), Engineering Service Building 1 & Engineering 1 Service Building 2 Workplace Optimization ($21.8 million), PN Campus Electrical Upgrades ($19.5 million), and PN Campus Parking Lots/Roads ($17.1 million).

Reference 1 also specifies the total project costs of the following project that will be in-service in 2027: the Montgomery Park and Sandy Beach Road Upgrades ($20.6 million).

Question(s):

a) Please explain key differences between the approved business case budgets of each of the facilities & infrastructure (F&I) projects in the preamble and the total project costs for each of the projects specified at Reference 1.

D2-Staff-106

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Attachment 2 / p. 4

Preamble:

At Reference 1, KPMG states identified opportunities for improvement “that should be addressed to further enhance the reliability and accuracy of the estimate”, including “finalizing and integrating program-level Basis of Estimate (“BOE”) and Basis of Schedule (“BOS”) documents […]”.

Question(s):

a) Please provide an update on OPG's response to KPMG's recommendation to finalize and integrate program-level BOE and BOS documents.
b) If available, please provide the Pickering Refurbishment Program (PRP) BOE and BOS documents.

D2-Staff-107

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Attachment 2 / p. 9

Preamble:

At Reference 1, KPMG recommends that "OPG clearly document how benchmarking cost data (particularly relating to the DNRP) has been applied", and cite "how benchmarking data and inputs from other project have been integrated and adapted to the specific considerations of the Pickering Refurbishment Program (PRP) and specific bundle."

Question(s):

a) Please provide an update on OPG's response to KPMG's recommendations regarding benchmarking cost data.
b) Please provide a summary of OPG's cost benchmarking of the PRP.

D2-Staff-108

Ref 1: Exhibit D2 / Tab 3 / Schedule 8 / Attachment 2 / p. 10

Preamble:

At Reference 1, KPMG states that "it is important that OPG has full access to vendor estimate packages, particularly during future target price negotiations where a comprehensive understanding of vendor pricing will enable OPG to effectively scrutinize and challenge costs".

At Reference 1, KPMG recommends that "OPG carry out an audit of the vendor estimate packages for Target Price contracts to ensure all associated documents, including any data and analysis supporting inputs and assumptions have been provided to OPG in accordance with the respective Vendor Agreements in order to confirm that OPG has the required documentation to effectively challenge the vendor's proposed target price."

Question(s):

a) Please provide an update on OPG's response to KPMG's statement regarding full access to vendor estimate packages.
b) Please provide an update on OPG's response to KPMG's recommendation regarding carrying out an audit of the vendor estimate packages for Target Price contracts.
c) How much of the total Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) do Target Price contracts represent in absolute and percentage terms?
d) How much of OPG's proposed PRP-in service amounts between 2026-2031 do Target Price contracts represent in absolute and percentage terms?

D2-Staff-109

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.7

Preamble:

At Reference 1, Pegasus-Global identified opportunities to improve Pickering Refurbishment Program (PRP) program-level governance, including "more explicit definition of cross-unit coordination responsibilities, enhanced articulation of program-level risk and assurance processes, and additional clarity on how contractor oversight, operational interfaces, and learning across units will be governed at the Program level."

Question(s):

a) Please provide an update on OPG's response to Pegasus-Global's recommendations regarding opportunities to improve PRP program-level governance.

D2-Staff-110

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.29

Preamble:

At Reference 1, Pegasus-Global states that the "RQE developed for the PRP is a Class 3 estimate […] based on Program maturity and design progression to approximately 36% for all major scopes as of November 2025."

Question(s):

a) Please clarify whether the 36% program maturity and design progression of the Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) refers to the total four-unit PRP RQE of $26.8 billion or just the Unit 5 in-service additions of $9,868 million between 2026-2031.
b) How does the level of program maturity and design progression (36%) that forms the basis of the PRP RQE compare to the level of program maturity and design progression that formed the basis of the Darlington Refurbishment Program (DRP) and Darlington New Nuclear Program (DNNP) RQEs?

D2-Staff-111

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.30

Preamble:

At Reference 1, Pegasus-Global states that the "RQE is based on a comprehensive Basis of Estimate (BOE) document that details the information and assumptions utilized in developing the estimate."

Question(s):

a) Please provide the Pickering Refurbishment Program (PRP) BOE document referenced in the preamble.

D2-Staff-112

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.31
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / Attachment 2

Preamble:

At Reference 1, Pegasus-Global states that the “management reviews were held to validate the overall adequacy of the RQE estimate” and that “OPG engaged a third-party to perform an independent review of the RQE estimate, including both the underlying processes and a detailed review of the estimate itself”.

Question(s):

a) Please provide a summary of the final OPG management review and validation (e.g., OPG board) of the Pickering Refurbishment Program (PRP) Release Quality Estimate (RQE) estimate.
b) If the independent third-party review of the PRP RQE estimate refers to something other than the KPMG review included at Reference 2, please provide it.

D2-Staff-113

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.46
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / p.18

Preamble:

At Reference 1, Pegasus-Global states that the “the Program also anticipates targeted independent reviews at major milestones to assess engineering maturity, execution readiness, and commissioning preparedness”.

At Reference 2, OPG describes Facilities & Infrastructure (F&I) projects that will be in-service in 2026 and 2027.

Question(s):

a) Please provide an update on OPG's plans for targeted independent reviews at major milestones to assess engineering maturity, execution readiness, and commissioning preparedness.
b) If applicable, please provide any independent reviews that were undertaken regarding the F&I projects described at Reference 2.

D2-Staff-114

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.50

Preamble:

At Reference 1, Pegasus-Global makes recommendations concerning "more explicit definition of cross-unit coordination responsibilities, enhanced articulation of Program-level risk and assurance processes, and additional clarity on how vendor oversight, operational interfaces, and learning across units will be governed at the Program level."

Question(s):

a) Please provide an update on OPG's actual or planned responses to Pegasus-Global's recommendations that are referenced in the preamble.

D2-Staff-115

Ref 1: Exhibit D2 / Tab 3 / Schedule 10 / Attachment 1 / p.65
Ref 2: Exhibit D2 / Tab 3 / Schedule 8 / p.18

Preamble:

At Reference 1, Pegasus-Global states that the Pickering Refurbishment Program (PRP) "is using a stage gate process to ensure costs are managed effectively and efficiently. Checkpoints are provided at each major project phase to ensure the Program is on track with regard to scope, cost, quality, and schedule." Pegasus-Global also states that "the Gate Review Board has responsibility for the gated process".

At Reference 2, OPG describes Facilities & Infrastructure (F&I) projects that will be in-service in 2026 and 2027.

Question(s):

a) Please summarize the latest Gate Review Board findings with respect to the scope, cost, quality, and schedule concerning the PRP's 2026-2031 Unit 5 in-service amounts requested by OPG.
b) Has the Gate Review Board reviewed the scope, cost, quality, and schedule of the F&I projects described at Reference 2? If so, please provide the findings. If not, please explain.

D2-Staff-116

Ref 1: Exhibit D2 / Tab 3 / Schedule 9 / p.13
Ref 2: Exhibit D2 / Tab 3 / Schedule 9 / p.14

Preamble:

At Reference 1, OPG states that the Major Projects Committee of the OPG Board of Directors has retained the Refurbishment Review Board to provide independent assessments of the Pickering Refurbishment Program (PRP). The Refurbishment Review Board performs reviews of PRP three to four times per year, or at a frequency as directed by the Major Project Committee, and reports directly to the Major Projects Committee

At Reference 2, OPG states that OPG's Internal Audit provides oversight in areas such as scheduling, cost estimates, contractor procurement, quality assurance, cost management, contractor time keeping and contracts. OPG's Internal Audit group has functional independence from management and publishes the results of audits in a report. The results of all audits are presented to OPG's Chief Executive Officer and OPG's Board of Directors.

Question(s):

a) Please provide a copy of any independent assessments of the PRP prepared by the Refurbishment Review Board for the Major Project Committee.
b) Please provide a copy of any independent assessments of the PRP prepared by OPG's Internal Audit group.

D2-Staff-117

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 27

Preamble:

Reference 1 states that “the RQE is based on a comprehensive Basis of Estimate (“BOE”) document that was prepared prior to execution phase review and approval. The BOE, along with the RQE, formed the basis of the cost estimate of $7.7 billion.”

Question(s):

a) Please provide the comprehensive Basis of Estimate document referenced in the preamble.

D2-Staff-118

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 27
Ref 2: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 22

Preamble:

At Reference 1, Pegasus-Global concludes that “that the RQE development process aligns with GAO’s best practices and twelve step estimate process […]”.

At Reference 2 Pegasus-Global lists the steps involved in the US GAO’s twelve-step guide to estimating. Step 7 is “Develop point estimate and compare it to an independent cost estimate”; step 8 is “Conduct sensitivity analysis”; step 9 is “Conduct risk and uncertainty analysis”; step 10 is “Document the estimate”; step 11 is " Present estimate to management for approval”.

Question(s):

a) Please provide the estimate presented to management for approval referenced in step 11 of the preamble.
b) Please provide a summary and explanation of OPG’s analysis of how the Darlington New Nuclear Program (DNNP) Release Quality Estimate (RQE)

compares to the point estimates and independent cost estimates that were relied upon in the development of the Basis of Estimate (BOE) and RQE.

D2-Staff-119

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 28

Preamble:

At Reference 1, Pegasus-Global concludes that “OPG’s estimating process is well-defined in its procedures and the results of the estimating process are fully explained within the BOE document as well as summarized in material presented to OPG’s Board.”

Question(s):

a) Please provide the summarized material presented to OPG’s Board that is referenced in the preamble.

D2-Staff-120

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 29

Preamble:

At Reference 1, Pegasus-Global concludes that “I find the estimating process OPG used to be reasonable and aligned with industry standards and what we have seen in other megaprojects.”

Question(s):

a) While Pegasus-Global’s conclusion in the preamble appears to relate to the estimating process that OPG used, did Pegasus-Global also independently assess the quantum/values of the estimates themselves and draw conclusions about them?

b) In Pegasus-Global's opinion, what is the appropriate role for independent cost estimate review of release quality estimates in a project like the Darlington New Nuclear Program (DNNP)?
c) In Pegasus-Global's opinion, what role, if any, did independent cost estimate review actually play in the DNNP?

D2-Staff-121

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 28
Ref 2: AACE International Recommended Practice No. 34R-05, Basis of Estimate. (05 Oct 2021) / pp. 5-6: https://web.aacei.org/docs/default-source/toc/toc_34r-05.pdf (publicly accessible sample)

Preamble:

At Reference 1, Pegasus-Global states that "OPG prepared a comprehensive BOE document that aligns with the guidelines established by AACE in its Recommended Practice on Basis of Estimates." (*AACE International Recommended Practice No. 34R-05, Basis of Estimate.* (05 Oct 2021))

At Reference 2, the AACE document states that a well-prepared basis of estimate will, among other things, facilitate the review and validation of the cost estimate. The document also identifies estimate basis reviews and estimate basis approval as components of the estimate development process.

Question(s):

a) Please provide OPG's validation of the Darlington New Nuclear Program (DNNP) cost estimate that is implied in Reference 2.
b) Please provide a summary of OPG's DNNP estimate basis reviews and DNNP estimate basis approval that are implied in Reference 2.

D2-Staff-122

Ref 1: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 33
Ref 2: Exhibit D2 / Tab 4 / Schedule 10 / Attachment 1 / p. 32

Preamble:

At Reference 1, Pegasus-Global states that OPG's selection of the Integrated Project Delivery (IPD) model is a reasonable and prudent choice and that the IPD model mandates a high level of collaboration, transparency, and shared risk and reward among the owner, architect, and contractor from the project's inception.

At Reference 2, Pegasus-Global states the "risk and reward sharing on the Darlington New Nuclear Program (DNNP) is established through the contingency strategy developed for small modular reactor 1 (SMR1), which includes a "risk pool" and a "reward pool" as part of the total project contingency amount […]".

Question(s):

a) In Pegasus-Global's opinion, what are the key risks related to the IPD risk and reward pool framework that owners and regulators should watch out for (for example, does the model incentivize inflated vendor/partner estimates)? Is OPG appropriately addressing such risks? How?
b) What, if any, related controls should be put into place by the OEB?

D2-Staff-123

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 59

Preamble:

Reference 1 describes the Integrated Project Delivery (IPD) Project Control team and Estimating team review process.

Question(s):

a) Please confirm whether the IPD Project Control team and Estimating team consists of OPG, GE-Hitachi, AtkinsRéalis, and AECON Kiewit. Otherwise, please clarify.
b) If some of the estimates that formed part of the Basis of Estimate (BOE) and Release Quality Estimate (RQE) were supplied by GE-Hitachi, AtkinsRéalis, and

AECON Kiewit, how did the IPD Project Control team and Estimating team validate the estimates?

c) Did the IPD Project Control team and Estimating team receive independent review of the estimates used in the BOE and RQE? If so, please provide a summary of the findings of the independent review and demonstrate how they affected the BOE and RQE. If not, why not?

D2-Staff-124

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 59

Preamble:

Reference 1 states that the Integrated Project Delivery (IPD) Project Control team and Estimating team review process includes the following steps:

1. Estimate Walk Through - Reports and Data

2. Project Scope and Technical Review

3. Contract Compliance Review

4. Estimate Team Reviews: Peer, Quality, Vetting and Validation

5. Project Team Reasonability Review ("Final review" which determines the reasonability of the estimate)

Question(s):

a) Please provide a copy of the "Project Team Reasonability Review (Final review […])" referenced in item 5 of the preamble.
b) Please clarify the approvals process that the Project Team Reasonability Review went through within OPG after it was prepared by the Project Team.
c) Please highlight key changes to the Darlington New Nuclear Program (DNNP) cost estimate between the Project Team Reasonability Review and the Release Quality Estimate (RQE) and explain why the changes were made.

D2-Staff-125

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 59

Preamble:

Reference 1 states: “RQE roadmap details 'Final (estimate) Package for Exec Review' and further 'ELT Review' and 'CEO Update' which can be assumed to align with the Project Team Reasonability Review / Final Review. Also noted are PLT Challenge Sessions.”

Question(s):

a) Please provide a copy of the “Final (estimate) Package for Exec Review” referenced in the preamble and describe key changes between the final package and the Release Quality Estimate (RQE).
b) Please provide a copy of the “CEO update” referenced in the preamble and describe key changes between it and the RQE.

D2-Staff-126

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 59

Preamble:

At Reference 1, the Better Through Total Collaboration report (BTTC) states that “although a substantial and comprehensive estimate review process has been undertaken, it is evident that the review process does not align with that stated in the Estimate Plan.”

Question(s):

a) In BTTC’s opinion, what is the consequence of the lack of alignment between the Darlington New Nuclear Program (DNNP) estimate review process with what is stated in the Estimate Plan?
b) What, if any, related recommendations has BTTC proposed?
c) How has OPG addressed the recommendations?
d) In BTTC’s opinion, has OPG addressed the recommendations appropriately?

D2-Staff-127

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 59

Preamble:

At Reference 1, Better Through Total Collaboration (BTTC) states that “Estimate peer checks and reviews have taken place to review estimating methodologies and cross check cost model calculations.”

Question(s):

a) In BTTC’s opinion, what is the appropriate role for independent cost estimate review in a project like the Darlington New Nuclear Program (DNNP)?
b) In BTTC’s opinion, how does this compare to the role that independent cost estimate review has actually played in the DNNP?
c) In BTTC’s opinion, what are the key risks related to OPG’s Basis of Estimates? Is OPG appropriately addressing such risks? How?
d) In BTTC’s opinion What, if any, related controls should be put into place by the OEB?

D2-Staff-128

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 7
Ref 2: Exhibit D2 / Tab 4 / Schedule 8 / Attachment 2 / p. 8

Preamble:

At Reference 1, Better Through Total Collaboration (BTTC) notes ten key recommendations for improvement across all control areas in assurance workstream 1, four of which are categorized as Category B (Important).

At Reference 2, BTTC notes four key recommendations for improvement across all control areas in assurance workstream 2, three of which are categorized as Category B (Important).

Question(s):

a) Please provide an update on how OPG is addressing the four areas for improvement which are categorized as Category B in assurance workstream 1.
b) Please provide an update on how OPG is addressing the four areas for improvement which are categorized as Category B in assurance workstream 2.
c) In BTTC's opinion, is OPG taking appropriate steps to address BTTC's category B recommendations for improvement in in assurance workstreams 1 and 2?

D2-Staff-129

Ref 1: Exhibit D2 / Tab 4 / Schedule 9 / Chart 2
Ref 2: Exhibit D2 / Tab 4 / Schedule 9 / p. 21
Ref 3: Exhibit D2 / Tab 4 / Schedule 8 / Table 1

Preamble:

At Reference 1, OPG summarizes program milestone progress as of September 2025.

At Reference 2, OPG states the Darlington New Nuclear Program's (DNNP) "critical path is 81 days behind the Working Schedule baseline plan as of September 30, 2025" and that "OPG is actively managing all delays and expects to be able to recover the delays incurred to date […]."

At Reference 3, OPG summarizes DNNP capital expenditures between 2020 and 2031.

Question(s):

a) Please update the chart at Reference 1 with current values.
b) Please clarify whether the budgeted capital expenditures in 2025 and 2026 reflect the delays summarized at references 1 and 2. If they do not, please provide an updated outlook for capital expenditures that reflects the delays and OPG's plans to recover them.

D2-Staff-130

Ref 1: Exhibit D2 / Tab 4 / Schedule 8 / Chart 2

Preamble:

At Reference 1, OPG summarizes Release Quality Estimate (RQE) budget and in-service additions for unit 1 according to work bundle categories and other categories.

Question(s):

a) Please compare the share (%) of line items 1-13 in chart 2 to the corresponding share from comparator projects that were included in OPG's Darlington New Nuclear Program (DNNP) Basis of Estimate (BOE). Please explain instances where there is a plus or minus 10% difference between the information in chart 2 and the comparator projects.
b) Please compare the share (%) of line items 1-13 in chart 2 to the corresponding share from the Darlington Refurbishment Program (DRP) and Pickering Refurbishment Program (PRP). Please explain instances where there is a plus or minus 10% difference between the information in chart 2 and the DRP and PRP. Please also clarify instances where comparisons may not apply.

D2-Staff-131

Ref 1: Exhibit D2 / Tab 4 / Schedule 9 / p.17
Ref 2: Exhibit D2 / Tab 4 / Schedule 9 / p.18

Preamble:

At Reference 1, OPG states that the Major Projects Committee of the OPG Board of Directors has retained the Small Modular Reactor Review Board to provide independent assessments of the Darlington New Nuclear Program (DNNP). The Small Modular Reactor Review Board reports directly to the Major Projects Committee.

At Reference 2, OPG states that OPG's Internal Audit provides oversight in areas such as scheduling, cost estimates, contractor procurement, quality assurance, cost management, contractor time keeping and Integrated Project Delivery (IPD) contracts. OPG's Internal Audit group has functional independence from management and publishes the results of audits in a report. The results of all audits are presented to OPG's Chief Executive Officer and OPG's Board of Directors.

Question(s):

a) Please provide a copy of any independent assessments of the DNNP prepared by the Small Modular Reactor Review Board for the Major Project Committee.
b) Please provide a copy of any independent assessments of the DNNP prepared by OPG's Internal Audit group.

D3-Staff-132

Ref 1: Exhibit D3 / Tab 1 / Schedule 1 / pp. 1-4
Ref 2: Exhibit D4 / Tab 1 / Schedule 1
Ref 3: Exhibit I1 / Tab 1 / Schedule 1

Preamble:

Reference 1 shows significant IT and Darlington New Nuclear Program (DNNP) Operational Readiness Technology capital investments.

Reference 2 provides OPG's capitalization thresholds and confirms that materiality is assessed on individual items. Some assets are centrally held and allocated through Asset Service Fees (ASFs).

Question(s):

a) Please confirm whether concurrent cost recovery (CCR) applies to:
    i. Centrally held assets allocated through the ASF
    ii. Joint-use IT assets
    iii. Only directly assignable generating assets
b) Please provide a breakdown of the CCR by asset class:
    i. Generating assets
    ii. IT assets
    iii. Intangible assets
c) Please explain how ASF allocations are adjusted to ensure no duplication of recovery where CCR applies.

D3-Staff-133

Ref 1: Exhibit D3 / Tab 1 / Schedule 2 / Attachment 1 / Tab 4 / pp. 3, 6-7

Preamble:

OPG indicated one of the six most significant Corporate projects ($30 million or greater) is the "ERP Finance Solution" which is estimated to cost $118.6 million. OPG notes that it currently uses SAP and it is reaching its end-of-life. As a result, OPG is upgrading to SAP S/4HANA and notes that it aligns with its "existing SAP ecosystem". OPG provided no alternatives in the Business Case Summary (other than not upgrading the existing SAP system now or not upgrading it at all).

Question(s):

a) Please identify if other SAP upgrade options are available that would have aligned with OPG's "existing SAP ecosystem" that were lower cost and would have represented an upgrade from OPG's current SAP. If so, please provide all such SAP alternatives, including the cost, and explain why OPG felt this higher cost option was necessary.

D4-Staff-134

Ref 1: Exhibit D4 / Tab 1 / Schedule 1 / pp. 1-2
Ref 2: Exhibit I1 / Tab 1 / Schedule 1

Preamble:

At Reference 1, OPG states that overhead costs that are only directly attributable to the acquisition or construction of a capital asset are capitalized, and that the implementation and license costs for certain cloud computing arrangements may be capitalized as intangible assets.

Reference 2 includes forecast calculations of Concurrent Cost Recovery (CCR) for both the Darlington New Nuclear Program (DNNP) and the Pickering Refurbishment Program (PRP) for 2027-2031.

Question(s):

a) For each year of 2027-2031, please provide a reconciliation of capitalized interest recorded to construction work-in-progress (CWIP), the CCR amount included in the revenue requirement, and the interest component embedded in rate base once the corresponding assets are placed in service.

b) Please confirm whether any capitalized interest recorded after the effective CCR date remains included in rate base. If so, please quantify the amount on an annual basis.
c) Please provide a schedule demonstrating that no duplication occurs between capitalized interest added to rate base and CCR recovered during construction.
d) Please confirm whether any intangible assets (including capitalized cloud implementation costs per Reference 1) are included in the CCR capital base.

EXHIBIT E – PRODUCTION FORECAST

E1-Staff-135

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Exhibit I1 / Tab 1 / Schedule 2 / Table 2

Preamble:

Reference 1 provides the Regional production trend from 2016 to 2027. 2016 to 2024 are presented as actual, 2025 to 2027 are provided as forecast and do not consider foregone production due to surplus baseload generation.

Reference 2 is the Computation of Percent Change in Hydroelectric Payment Amounts.

Question(s):

a) Please provide an updated table as in Reference 1, updating 2025 for actual production.
b) The 2026 budget pre-spill production forecast at Reference 1 is 32.7641 TWh while the 2026 budget pre-spill production forecast at Reference 2 is 32.9763 TWh. Please resolve this discrepancy, and update Reference 2 accordingly.

E1-Staff-136

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 / pp. 4-7
Ref 2: Exhibit D1 / Tab 1 / Schedule 1 / pp. 3-4

Ref 3: Exhibit F1 / Tab 1 / Schedule 1 / pp. 5-15

Preamble:

At Reference 1, OPG states the incremental production increases anticipated as a result of refurbishment projects at the generating stations completed by the test year have been incorporated into the forecasted energy production.

At Reference 2, OPG explains that during the forecast period 2027-2031, there are Turbine-Generator Refurbishment projects, and Station Redevelopment projects that increase unit capacities. At Reference 3, OPG further states that during the 2027-2031 forecast period, OPG expects to add an incremental capacity of 50 MW from the refurbishment projects (including Sir Adam Beck 1 & 2 GS and R.H. Saunders GS). OPG also expects to add an incremental 13 MW of capacity through the planned redevelopment projects during the forecast period.

Question(s):

a) Please confirm there is incremental capacity expected for the regulated hydroelectric generating stations from refurbishment projects and redevelopment projects during the entire 2027-2031 forecast period. If not confirmed, please explain.
b) Please confirm if the incremental capacity that will come into service between 2027 – 2031 is reflected in the 2027 production forecast. If not, please explain how each year's production forecast between 2028 – 2031 would differ from the 2027 production forecast.
c) Please confirm that OPG proposes to use the 2027 forecasted energy production approved by the OEB in this application to calculate production deviations for entries in the Water Conditions Variance Account during 2027-2031. If not confirmed, please explain. If confirmed, please explain how OPG plans to account for the increase in production resulting from the capital projects in the 2028-2031 period.

E1-Staff-137

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 pp. 5-6
Ref 2: Exhibit G1 / Tab 1 / Schedule 1 p. 3
Ref 3: Exhibit E1 / Tab 2 / Schedule 1 pp. 6-7

Preamble:

At Reference 1, OPG states that for the remaining 21 dispatchable regulated hydroelectric generating stations, the forecasting methodology has been modified from EB-2013-0321 to also account for spill due to unplanned outages.

At Reference 2, OPG explains the water that is currently unutilized at Sir Adam Beck 2 due to turbine modulation will soon be utilized to generate electricity behind the meter from the Niagara Hydrogen Center (NHC) being constructed. The electricity will then power an electrolyzer that produces low-carbon hydrogen. The NHC will come into service in 2026.

At Reference 3, OPG explains instances when the locational price does not explain situations where OPG's hydroelectric energy offers are not dispatched, resulting in curtailment. OPG states that this situation has been considered in the hydroelectric production forecast.

Question(s):

a) Please explain the detailed mechanism of how the unplanned outage spill is quantified and applied to the final production forecast amount.
b) For the other six dispatchable regulated hydroelectric generating stations in the Niagara, Welland, and St. Lawrence river systems, please explain if the methodology has also been updated to account for unplanned outage spill. If not, please explain why.
c) Please confirm whether the production at the NHC is considered in the Niagara Utilization Monthly Model that is being used to forecast the Sir Adam Beck Complex production. If not, please explain. If it is considered, what is the impact to hydroelectric production in each month of the 2027 production forecast?
d) Please quantify the impact of the production forecasting modification described at Reference 1 by Region and month of the 2027 production forecast.
e) Please quantify the impact of the production forecasting modification described at Reference 3 by Region and month of the 2027 production forecast.
f) For each modification to the production forecast, please explain the methodology of the analysis that determined the impact or input into the 2027 hydroelectric production forecast. For example, what is the historical time period of that analysis? Please describe the analysis for each region.

E1-Staff-138

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 Table 2
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 Table 2
Ref 3: EB-2023-0336 Exhibit H1 / Tab 1 / Schedule 1 Table 2
Ref 4: EB-2020-0290 Exhibit H1 / Tab 1 / Schedule 1 Table 2
Ref 5: EB-2018-0243 Exhibit H1 / Tab 1 / Schedule 1 Table 2

Preamble:

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

From References 2-5, OEB staff has summarized the historical Forecast Production and Actual Calculated Production values from OPG's Hydroelectric Water Conditions Variance Account in Table 1.

Table 1 – Water Conditions Variance Account Summary

	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Forecast Production (TWh)	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4
Actual Calculated Production (TWh)	33.6	35.7	34.0	34.6	34.7	31.7	34.8	33.9	33.7
Variance (TWh)	**-1.1**	**-3.3**	**-1.6**	**-2.1**	**-2.2**	**0.8**	**-2.4**	**-1.5**	**-1.2**

Question(s):

a) Please confirm the values presented in Table 1: Water Conditions Variance Account Summary. If not confirmed, please provide the updated values.
b) Please explain how OPG has considered the consistent trend, seen in Table 1, of higher flows than forecast in developing the 2027 test year production forecast.

H1-Staff-139

Ref 1: **Exhibit E1 / Tab 1 / Schedule 1 Table 2**
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 Table 5

Ref 3: EB-2023-0336 Exhibit H1 / Tab 1 / Schedule 1 Table 5
Ref 4: EB-2020-0290 Exhibit H1 / Tab 1 / Schedule 1 Table 5
Ref 5: EB-2018-0243 Exhibit H1 / Tab 1 / Schedule 1 Table 5
Ref 6: Exhibit I1 / Tab 1 / Schedule 1 / Attachment 1
Ref 7: Exhibit E1 / Tab 1 / Schedule 2 / pp. 1-2

Preamble:

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

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

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

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

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

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

Table 2 – Summary of Revenue Deficiency – Regulated Hydroelectric

Description	**2027**	**2027 Using Pre-spill Average**
Forecast Production (TWh)	32.5	33.3

2026 Payment Amount per EB-2020-0290 ($/MWh)	43.88	43.88
Indicated Production Revenue ($ millions) (line 1 x line 2)	**1,424.4**	**1,461.2**
Difference in Indicated production Revenue ($ millions)		**36.8**
Revenue Requirement ($ millions)	1,668.3	1,668.3
Revenue Requirement Deficiency ($ millions) (line 4 - line 3)	**243.9**	**207.1**
Difference in Revenue Requirement Deficiency ($ millions)		**-36.8**

Question(s):

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

E1-Staff-140

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 Table 1
Ref 2: OPG Annual Financial Reports 2016 – 2024
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 Table 5

Preamble:

From References 1-3, OEB staff has summarized the historical Hydroelectric Availability for applicable stations and the pre-spill production amounts between 2016 – 2024, and the budget and forecast production amount for the year 2026 and 2027 as presented in the exhibit in Table 1 below.

Table 1 – Unit Availability and Pre-spill Hydroelectric Production Amount

	2016	2017	2018	2019	2020	2021
Hydroelectric Unit Availability (%)	89	88	86	86.6	88.2	88.4
Pre-spill Production (TWh)	33.8	35.9	33.0	33.8	34.6	30.9

	2022	2023	2024	2025	2026	2027
Hydroelectric Unit Availability (%)	86.9	85.4	85.8			
Pre-spill Production (TWh)	32.7	32.4	32.8		32.8	32.5

Question(s):

a) Please confirm the values presented in Table 1: Unit Availability and Pre-spill Hydroelectric Production Amount. If not, please provide correct values.
b) Please provide the actual Hydroelectric Unit Availability (%) and the actual Pre-spill Production (TWh) amounts for the year 2025.
c) Please provide the Hydroelectric Unit Availability (%) used in the year of 2026 and 2027 for the production forecast.
d) For the 2026 and 2027 forecast years, please identify the generating stations that have any instances of production being limited by the availability capacity. For each of those stations, please identify the percentage of time in the forecast year where the station is limited by the capacity of the available units.

E1-Staff-141

Ref 1: Exhibit E1 / Tab 1 / Schedule 1 / Table 2
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / pp. 8-9
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / Table 2
Ref 4: EB-2013-0321, Exhibit E1 / Tab 1 / Schedule 1 / Table 2
Ref 5: EB-2013-0321, Exhibit N1 / Tab 1 / Schedule 1 / Chart 10
Ref 6: Exhibit A1 / Tab 3 / Schedule 4 / p.3

Preamble:

At Reference 1, OPG presents the 2027 Test Year Regulated Hydroelectric Production forecast. At Reference 2, OPG describes how the EB-2013-0321 OEB-approved Regulated Hydroelectric Production forecast is implemented as the reference forecast for the Water Conditions Variance Account.

The EB-2013-0321 OEB-approved forecast was originally filed with Reference 4. With Reference 5, OPG updated the production forecast for hydroelectric generation from, what was known at the time as, the Niagara Plant Group and the RH Saunders Generating Station.

Question(s):

a) Please confirm that the Water Conditions Variance Account methodology treats Decew Falls 1 and Decew Falls 2 generating stations in the same manner as described for Sir Adam Beck 1 and 2, and the RH Saunders generating stations. The description at Reference 2, page 8, lines 13 to 23 does not identify these two generating stations. If not confirmed, please explain.
b) Please confirm each of the items below, and if not confirmed, please explain each item:
   i. The OEB-approved EB-2013-0321 regulated hydroelectric production forecast, when annualized, such as for the purposes of the Water Conditions Variance Account, is 33.0 TWh. If this is not confirmed, please explain and provide a monthly summary table of monthly production by Region in excel with unrounded data for one year.
   ii. Please confirm that the difference between the EB-2013-0321 OEB-approved regulated hydroelectric production forecast, of 33.0 TWh, and the Water Conditions Variance Account forecast production, of 32.432 TWh, is due to exclusion of the regulated hydroelectric facilities that do not have modelled production forecasts.
c) Please confirm that OPG agrees that the last OEB-approved Regulated Hydroelectric Production forecast is that forecast approved in EB-2013-0321. If not confirmed, please explain. If it is OPG's view that the OEB approved a Regulated Hydroelectric Production forecast for setting base hydroelectric payment amounts since EB-2013-0321, please provide reference to the OEB Decision and Payment Amounts Order that approved that forecast.
d) Please explain the meaning of "the production used in the calculation underpinning the 2026 regulated hydroelectric payment amount" in Reference 6. OEB staff does not understand OPG's use of the words "used" and "underpinning" in the context of EB-2016-0152 and in the context of Reference 2 p. 8 at lines 22 and 23. How does a forecast that "underpins" payment amounts differ from an OEB-approved production forecast? Please elaborate and explain.
e) Please confirm that in each of EB-2013-0321, EB-2016-0152, EB-2018-0243, EB-2020-0290, and EB-2023-0336, OPG proposed, and the OEB approved, the

disposition of DVA balances in those proceedings on the basis of a 33.0 TWh annual production forecast for the regulated hydroelectric generating stations.

f) Please reproduce Reference 1, in excel format with un-rounded data, to add a row showing the cumulative monthly production from the hydroelectric generating stations without a modelled production forecast in each month of the test year.

E1-Staff-142

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / Chart 4
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / Chart 7

Preamble:

At Reference 1, OPG provided a table setting out "HIM Payments in Market Renewal 2025 ($M)" for the months of May to September.

At Reference 2, OPG provided a table setting out "OPG Regulated Hydroelectric MWPs ($M)" for the months of May to September.

Question(s):

a) Please update both tables to include all months since the Market Renewal Program (MRP) was implemented for which data is available (which OEB staff currently expects will include March 2026).

E1-Staff-143

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 1
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / p. 19
Ref 3: Exhibit G1 / Tab 1 / Schedule 1 / Table 1
Ref 4: Exhibit G1 / Tab 1 / Schedule 2 / Table 1

Preamble:

At Reference 1, OPG indicates it is seeking the following approvals (as settled in EB-2023-0336):

- Continue to book amounts in the Surplus Baseload Generation Variance Account (SBGVA) based on the revised local and global SBG spill methodology.
- Continue to be settled according to the revised Hydroelectric Incentive Mechanism (HIM) (which includes separate day-ahead and real-time incentives and uses locational prices based on daily average).
- Continue the revised HIM adjustment for spill (“unintended benefit”).
- Continue to retain Real-Time Energy make whole payments (MWPs).

OPG also indicates it is seeking approval to eliminate the sharing of HIM revenues above the threshold.

At Reference 2, which is the “Conclusion” to this section of the Application, OPG proposes to “Establish a HIM forecast for 2027 (as described in Ex. G1-1-1)”. OEB staff was unable to find a clear description of that phrase in Ex. G1-1-1.

At Reference 3 and Reference 4, OPG provided a forecast of HIM revenues for each year of the five-year IR term, as set out in the table below.

Table 1 – Forecast HIM Revenues (per References 3 and 4)

	2027	2028	2029	2030	2031
HIM Revenues ($M)	17.8	8.2	9.2	13.7	12.4

Question(s):

a) Is OPG requesting approval of all five years for which HIM revenues have been forecast in the application?
b) Does singling out 2027, in proposing to “Establish a HIM forecast for 2027”, mean OPG is proposing to establish a new HIM “threshold” based on the forecast of $17.8 million for 2027?
c) If OPG is not seeking approval of the HIM revenues that have been forecast for the five years of the IR term or a change to the HIM threshold, please clarify what OPG is proposing, as OEB staff was unable to locate a reference to a HIM forecast in the list of requested approvals quoted above or in the “Approvals” section of the application.
d) Please explain the methodology used by OPG to arrive at $17.8 million for 2027. Please also explain how OPG arrived at the forecast HIM revenues for the subsequent years in the IR term (if the approach differed).

E1-Staff-144

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 1
Ref 2: MSP Monitoring Report 32, July 16, 2020 / pp. 70, 72
Ref 3: MSP Monitoring Report 32, July 16, 2020 / p. 68
Ref 4: Exhibit E1/ Tab 2 / Schedule 1 / p. 17

Preamble:

At Reference 1, OPG states the following in summarizing the Market Surveillance Panel's (MSP) Monitoring Report 32:

> "the MSP expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM … the MSP recommended the OEB consider revisiting the sharing with consumers of HIM net revenue exceeding a threshold. The [MSP] raised multiple arguments in support of the elimination of sharing. Consistent with OPG's analysis in section 5.5.1, the MSP stated that the sharing is a dilution of OPG's incentive to time-shift production."

At Reference 2, the MSP stated in its report that "OPG has suggested several reasons for the reduction of output at PGS other than the reduced effectiveness of the HIM." The MSP subsequently noted "Again, OPG has presented a number of reasons why they have reduced time-shifting at the initial prescribed assets (excluding PGS) over this time period." In both cases, OPG provided reasons and none were related to the Hydroelectric Incentive Mechanism (HIM). As a result, the MSP noted "The Panel accepts that those issues have had some effect, but has not been able to assess its extent and therefore cannot be sure that the sharing of HIM revenues has not contributed to the reduction [in time-shifting]."

At Reference 3, within the context of discussing OPG's incentive to "offer their water efficiently", the MSP stated: "That revenues have been well below the 2013 forecast also means that the sharing of revenues above the forecast threshold could not have had the effect of diluting the incentive."

At Reference 4, OPG discusses the impact of HIM revenue sharing on the Pump-Generating Station (PGS) price spread.

Question(s):

a) Please explain how OPG's rationale in the Application aligns with the explanations previously provided to the MSP regarding time-shifting and revenue sharing.

b) Please also explain why OPG did not reference the HIM revenue sharing in providing reasons to the MSP in relation to reduced time-shifting of production (including and excluding the PGS).
c) Given that OPG proposes to eliminate HIM revenue sharing for all of its prescribed hydroelectric facilities, has OPG conducted analysis, similar to that summarized in Reference 4 regarding the PGS, to identify the effect of HIM sharing on its ability to time-shift water at its regulated facilities other than the PGS?

E1-Staff-145

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 1
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / Attachment 1 / p. 24 (SBGVA Study)

Preamble:

At Reference 1, OPG states: “The findings demonstrate that targeted adjustments to PGS cost treatment and HIM net revenue sharing can improve incentives for OPG to time-shift generation in ways that lower spill and benefit ratepayers.”

At Reference 2, in the “Conclusion” of the study, OPG discusses its “findings” in summarizing the three options that were assessed: (1) Removing Variable Load Charges (Network Service Charge & IESO Administration Fee) applicable to Pump-Generating Station (PGS) cycling; (2) Removing the Gross Revenue Charge (GRC) applicable to PGS generation; and (3) Eliminating Hydroelectric Incentive Mechanism (HIM) sharing above the established Hydroelectric Incentive Mechanism Variance Account (HIMVA) threshold. OPG provided estimated quantitative impacts for the first two options. For example, for Option 1, OPG estimated an increase in PGS generation (20.3 GWh), reduced Surplus Baseload Generation (SBG) spill (25.2 GWh), and a reduction in Total Customer Costs ($8.8 million). For the HIM-related option, no quantitative benefits were provided and, instead, OPG reiterated the Market Surveillance Panel’s (MSP) support of the proposed change.

Question(s):

a) Similar to Option 1, please provide quantitative estimates for the HIM-related option to “demonstrate” the “lower spill and benefits to ratepayers” and to facilitate a comparison of all the options. If OPG is not able to do so, please explain why it is not possible to provide any estimates and how the findings related to this option demonstrate lower spill and benefits to ratepayers.

E1-Staff-146

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / Attachment 1 / p. 13 (SBGVA Study)
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / Attachment 1 / p. 24 (SBGVA Study)

Preamble:

At Reference 1, within the context of discussing the EB-2022-0325 Decision and Order, which exempted energy storage facilities from paying transmission charges, it notes that "OPG is in the process of determining the feasibility of implementing an NSC exemption for the PGS by designating it as an energy storage facility. OPG notes that, if the PGS receives the transmission charge exemption, the PGS would be available to pump in all hours of the day without incurring the NSC, and the load charge factor in the PGS economic formulas would be reduced. OPG expects a decision to be reached in 2026."

At Reference 2, OPG explains three options were assessed. Option 1 involved removing the transmission Network Service Charge (NSC) & the IESO Administration Fee applicable to Pump-Generating Station (PGS) cycling and Option 3 involved eliminating Hydroelectric Incentive Mechanism (HIM) sharing above the established HIM threshold.

Question(s):

a) Of the three options that OPG assessed, please identify which option would provide OPG with the greatest incentive to time-shift production and please explain why.
b) Given the relative size of the transmission NSC versus the IESO Fee, would changing the designation of the PGS to an energy storage facility essentially result in the implementation of Option 1 since both would result in an exemption from the NSC?
c) If the designation of the PGS was changed to an energy storage facility, would there still be a material incremental incentive for OPG to time-shift production if HIM revenue sharing above the threshold was also eliminated? If so, please explain how material the incremental incentive would be.

d) Since the MSP based their analysis and recommendation discussed in the Application on the PGS being designated as a generation facility, does OPG believe the MSP's assessment would still be applicable if the PGS becomes an energy storage facility?
e) Please clarify when, in 2026, OPG expects to make a decision related to the designation of the PGS. Please also explain why OPG did not make that decision before the Application was submitted.

E1-Staff-147

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / Attachment 1 / pp. 15-17

Preamble:

At Reference 1, OPG explains its modelling analysis that was used to forecast the Hydroelectric Incentive Mechanism (HIM) customer benefits for the test years by comparing “time-shifting hydroelectric resources” to a “flatter scheduling profile”. Chart 6 shows how OPG calculated the modelled changes in customer costs. OPG notes that the higher customer benefit in 2027 (relative to 2026) is due to forecasted increases in Ontario Zonal Prices, 5 TWh of incremental demand, and no Pickering B generation after it comes offline for refurbishment in September 2026. OPG has assumed those factors will increase reliance on gas-fired generation and imports to meet demand.

Question(s):

a) Please elaborate on a “flatter scheduling profile”. For example, does that mean no time-shifting of hydroelectric resources (e.g., Pump-Generating Station (PGS) operated like baseload)?
b) Please provide a table that sets out the underlying assumptions that were used to complete Chart 6 (separately for 2026 and 2027) including the following: $/MWh and MWh (for OPG generation, non-OPG generation and imports), the amount of Surplus Baseload Generation (SBG)-related Generation Curtailment, the Real-Time Ontario Zonal Price (OZP) and Day-Ahead OZP, economic time-shifting (MWh), HIM-driven incremental time-shifting (MWh), etc.

E1-Staff-148

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 4
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / p. 5
Ref 3: Exhibit E1 / Tab 2 / Schedule 1 / p. 6
Ref 3: Congestion Management Settlement Credits (CMSC) In the IMO-Administered Electricity Market / MSP / p. 3

Preamble:

At Reference 1, OPG notes that at the IESO's Renewable Integration Stakeholder (RIS) Engagement, "IESO described that SBG conditions can occur on both a global and local level … Local SBG was similarly defined as "a condition that occurs when a region's electricity production from baseload facilities … would otherwise be greater than the local demand and the transmission system's ability to move the excess generation out of the area".

At Reference 2, OPG explains that, in the Legacy Market, only global Surplus Baseload Generation (SBG) conditions were used to calculate Surplus Baseload Generation Variance Account (SBGVA) entries and the uniform price was a good indicator of global SBG because it did not reflect the impact of congestion. However, the Application notes:

> "OPG is unable to accurately distinguish between spill due to global and local SBG conditions as defined in IESO's [RIS] Engagement … OPG assessed market constraints by comparing the constrained and unconstrained schedules published in the Legacy Market. This process ensured that forgone generation due to market constraints, including those related to local SBG, were not booked in the SBGVA, as they may also attract CMSC payments. The Renewed Market's use of a single schedule eliminates OPG's ability to identify spill attributable to market constraints".

At Reference 3, the Market Surveillance Panel (MSP) describes conditions that resulted in a CMSC payment in the Legacy Market:

> "Generators … may be 'bottled' because of transmission constraints that prevent them from getting the output they have offered to where the demand is. In such circumstances they will be told not to produce and will receive constrained off payments equivalent to the difference between the market price and their accepted offer."

At Reference 4, OPG explains that SBG conditions are generally expected to be present when the applicable real-time Locational Marginal Pricing (LMP) for a given resource falls below its applicable Gross Revenue Charge (GRC) price threshold.

Question(s):

a) As OPG noted, it is unable to "accurately" distinguish between spill due to global and local SBG conditions. Please describe if OPG assessed any options to provide a "rough" estimate of local spill. If so, please explain those options and why they were considered not to be appropriate by OPG. If OPG did not undertake this type of assessment, please explain why.
b) Is there any difference between OPG receiving a CMSC payment due to a transmission constraint (in the Legacy Market) and OPG receiving a payment for local spill (in the Renewed Market), aside from the payment being based on the difference between the market price and accepted offer (CMSC payments) and the regulated hydroelectric payment amount (Local Spill)? Please explain.
c) Please provide a table that includes, for the most recent five years of the Legacy Market, the annual amounts that OPG received from the IESO in CMSC payments and the annual amounts that OPG booked to the SBGVA.
d) Please elaborate on "SBG conditions are generally expected to be present when … real-time LMP for a given resource falls below its … GRC price threshold". In doing so, please reflect the following:
   i. Please confirm that is the expectation because the GRC represents the minimum offer price that would allow OPG to recover its cost of production associated with the applicable regulated generation facility.
   ii. Please also confirm "SBG conditions" in the excerpt above would indicate "Local" SBG. If so, please explain why this could not be used as a basis to estimate Local SBG. If not, please explain how it could indicate only "Global" SBG.
e) Please identify if OPG has investigated with the IESO the possibility of using metering to detect Local vs. Global SBG. If OPG has done so, please explain the results of those discussions. If not, please explain why.

E1-Staff-149

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 5

Preamble:

At Reference 1, OPG explains that, in the Legacy Market, as detailed in EB-2013-0321, OPG calculated forgone production due to Surplus Baseload Generation (SBG) by starting with the "total" volume of spill and then "subtracting" the volume of spill due to the following – “water conveyance constraints, production capability, market constraints and contractual obligations”.

OPG further explains, in the Renewed Market, due to the change from a uniform price to Locational Marginal Pricing (LMP), the volume of spill related to “market constraints” can no longer be determined. As such, market constraint volumes are no longer subtracted from the total volume of spill in OPG’s calculation of an SBG entry in the Surplus Baseload Generation Variance Account (SBGVA).

Question(s):

a) Has OPG done historic analysis related to breaking down the volume of spill due to the four factors – water conveyance constraints, production capability, market constraints and contractual obligations? If so, please provide the results in a table for the years that OPG completed that analysis.
b) Please confirm that, if the volume of spill associated with “market constraints”, could be calculated, it would be equal to the volume of what is termed “local” spill in the Application. If that is not the case, please explain the difference.
c) Please explain if there is a difference between forgone production due to “market” constraints and “transmission” constraints (i.e., unable to get output offered to where demand is due to transmission system). If there is a difference, please explain the other types of constraints included in market constraints (including how there is no relationship to the transmission system) and please also clarify the materiality of constraints that are not related to transmission.
d) Please comment on whether the change in approach under the Renewed Market calculation — where spill associated with market constraints is included in the SBGVA rather than subtracted (as it was under the Legacy Market calculation) — affects the level of SBG-related compensation to OPG relative to Legacy Market years. If OPG does not believe this change in methodology leads to over-compensation, please explain why.

E1-Staff-150

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 13-14
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / Attachment 4
Ref 3: Exhibit E1 / H-SEC-05 (EB-2023-0336)

Preamble:

At Reference 1, OPG notes that Surplus Baseload Generation (SBG) conditions were considered to be present when the uniform market price fell below the Gross Revenue Charge (GRC) price threshold. OPG also noted that the Surplus Baseload Generation Variance Account (SBGVA) debit entries in the account were $29.7 million in 2023 and $10.6 million in 2024. The applicable market price in those years was the Hourly Ontario Energy Price (HOEP).

At Reference 2, OPG provided a spreadsheet that includes the following information: Date, Hour, Foregone Production due to SBG, Addition to SBGVA, and HOEP. That information was provided for a total of 4,107 hours. Of those hours, based on a GRC of $14.40/MWh, there were 1,794 hours where HOEP exceeded the GRC, including 14 hours where HOEP was over $100/MWh. OEB staff notes that this Attachment 4 is provided to support clearance of the SBGVA.

At Reference 3, in an interrogatory response to SEC (in the EB-2023-0336 proceeding), OPG attempted to explain why the HOEP would exceed the GRC in some hours when the information in the spreadsheet was first requested. In that response, OPG noted "its SBG spill algorithm" begins with "quantifying SBG spill in hours when HOEP is less than the applicable GRC". OEB staff does not fully understand the remainder of OPG's response. For example, it states the algorithm "allocates this spill as SBG spill <u>if in a previous</u> SBG hour within that day, the algorithm identifies energy that would have been generated absent SBG conditions but was not realized as actual spill". OPG further noted that, for that reason, the attachment to the interrogatory response "shows SBG entries in hours when HOEP exceeds OPG's applicable GRC <u>rather than the originating hour</u>". [emphasis added]

Question(s):

a) Is the "originating hour" the hour when the SBG event began? If so, why would the "previous" hour be considered an SBG hour and the appropriate hour for the SBGVA entry?
b) Given the Legacy Market was a real-time market and the underlying intent of the SBGVA is to compensate OPG for forgone production where OPG needs to spill water (rather than produce energy) in the applicable hours, please explain why the hour associated with the SBGVA entry is the "previous hour" rather than the same hour as the hour where OPG's algorithm is "quantifying SBG spill in hours when HOEP is less than the applicable GRC".
c) Please modify Attachment 4 (i.e., Reference 2) by adding a column that includes the HOEP for the "previous" hour.

E1-Staff-151

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / pp. 7-8
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / Chart 2

Preamble:

At Reference 1, OPG notes that "Under the Renewed Market, spill volumes observed to date have remained generally consistent on a month-over-month basis with levels recorded since 2021."

At Reference 2, OPG provided a table that sets out "SBG Spill Booked to SBGVA (MWh)" on a monthly basis, for 2021 – 2025.

OEB staff focused on comparing the same subset of months that Surplus Baseload Generation (SBG) spill data was provided by OPG for the Renewed Market (May to September) across all the years. That is reflected in the chart below which shows the amount of SBG spill booked to the Surplus Baseload Generation Variance Account (SBGVA) declining substantially in the years before Market Rate Program (MRP) was implemented – from 2021 & 2022 (both years over 700 MWh) to 2024 (151 MWh). In the months following MRP Go-Live, it then increased considerably (547 MWh).

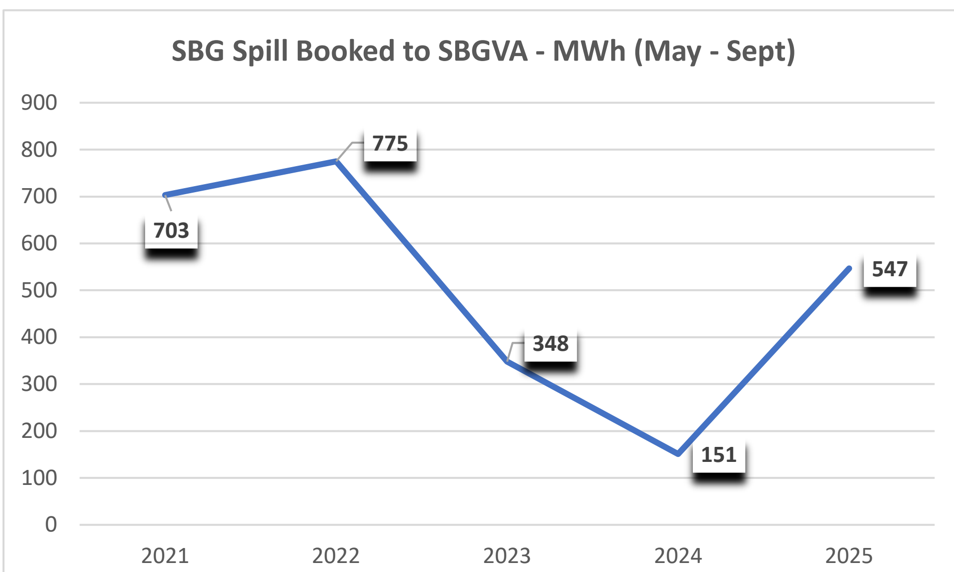

Chart 1 – SBG Spill Booked to SBGVA – MWh (May – Sept)

Question(s):

a) Please explain the substantial increase in the initial months of the Renewed Market after a year-over-year declining trend during the same months in the Legacy Market years. Please include in that explanation whether the increase from 2024 to 2025 was attributable to OPG actually spilling almost four times as much water or the change in methodology to do the calculation.

E1-Staff-152

Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / p. 22
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / p. 23

Preamble:

At Reference 1, OPG notes "In EB-2023-0336, OPG … received approval to retain Real-Time Energy MWPs … OPG proposes that the treatment of Real-Time Energy MWPs … as settled in EB-2023-0336 continue throughout the upcoming rate-setting period."

At Reference 2, OPG notes "for administrative efficiency, OPG proposes to forgo receiving all Energy and OR MWPs during the IR term."

At Reference 3, OPG notes "OPG's proposal included an underlying assumption that OPG will receive [Operating Reserve] MWPs".

Question(s):

a) Given "all" Energy Make Whole Payments (MWPs) would include Real-Time (RT) Energy MWPs, please clarify what OPG is proposing in stating "retain" RT Energy MWPs in the first reference and "forgo" them in the second reference above.
b) Please clarify the "assumption" that OPG will "receive OR MWPs" within the context of OPG receiving approval to retain only RT Energy MWPs (and OPG proposing to continue that in this Application).

E2-Staff-153

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / Table 1a and 1b

Preamble:

Reference 1 provides OEB-approved and actual nuclear production and other information between 2020 and 2025. The values for 2025 are budgeted.

Question(s):

a) Please update the tables at References 1 with actual values for 2025.

E2-Staff-154

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / Chart 4
Ref 2: Exhibit E2 / Tab 1 / Schedule 1 / pp. 14-15
Ref 3: Exhibit E2 / Tab 1 / Schedule 2 / Table 1b

Preamble:

At Reference 1, OPG summarizes forced loss rates at Darlington between 2020 and 2024.

At Reference 2, OPG indicates that Units 1 and 4 forced loss rate targets were reduced to 6% and 4% for the first and second year respectively post-refurbishment given operating experience and lessons learned from Units 2 and 3.

At Reference 3, OPG includes forecasted forced loss rates at Pickering and the Darlington New Nuclear Program (DNNP).

Question(s):

a) Please provide a chart/table that provides a unit-by-unit summary of actual forced loss rates at Darlington between 2020 and 2024 and forecasted forced loss rates between 2025 and 2031 (with actuals for 2025 if available). Please also include a summary of corresponding forced loss rate days equivalent.
b) Please elaborate on how OPG's operating experience and lessons learned from Darlington Units 2 and 3 led to reduced forced loss rate targets for Darlington units 1 and 4.

c) Pickering's Unit 5 forced loss rate is set at 12% for the first-year post refurbishment; DNNP Unit 1 forced loss rate is also set at 12% for its first year of operation. Why are the forecasted forced loss rate for Darlington Units 1 and 4 so much lower during their first and second years of operation (i.e., 6% and 4%)?
d) Please describe how OPG's operating experience and lessons learned from Darlington Units 2 and 3 have informed forced loss rate targets for Pickering Unit 5 and DNNP Unit 1.

E2-Staff-155

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / p. 4

Preamble:
At Reference 1, the Applicants state that "Darlington continues to target an improved FLR performance, set at 2.0% FLR over the 2028-2031 period once Units 1 and 4 enter their third year of post-refurbishment operations."

Question(s):

a) Please clarify the basis on which OPG is targeting a 2.0% forced loss rate (FLR) for Darlington over the 2028-2031 period.

E2-Staff-156

Ref 1: Exhibit E2 / Tab 1 / Schedule 1 / pp. 4-5

Preamble:

At Reference 1, OPG discusses the Darlington Steam Generator Primary Moisture Separators (PMS) Replacement projects.

Question(s):

a) Please explain how, if at all, the OEB-approved production forecast for 2022-2026 accounted for the PMS replacement outages.

b) Please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term and in the 2027-2031 rate term of deferring the Unit 2 PMS replacement work from 2025 to 2027.
c) If the Unit 3 PMS replacement work is a deferral of work that OPG initially planned to undertake earlier in the 2022-2026 IR term, please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term of the deferral.
d) Did OPG complete the PMS replacements associated with the four Steam Generators at Unit 1 and the PMS replacements associated with the four SGs at unit 4 during the Unit 1 and Unit 4 refurbishment outages? If not, please clarify.

E2-Staff-157

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / pp. 4-5

Preamble:

At Reference 1, OPG discusses the Darlington steam generator chemical clean, stator rewind, and turbine rotor replacement projects.

Question(s):

a) Please clarify whether any of the projects cited in the preamble are deferrals of work initially planned for the 2022-2026 rate term.
b) If any of the projects cited in the preamble are deferrals from the 2022-2026 rate term, please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term and in the 2027-2031 rate term.
c) Please explain how, if at all, the OEB-approved production forecast for 2022-2026 accounted for the Primary Moisture Separators (PMS) replacement outages.

E2-Staff-158

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / p. 5

Preamble:

At Reference 1, the Applicants state that it is "planning for Turbine Rotor Replacements for all four Darlington units starting in 2029, with three units' replacements being completed during the IR term in their respective planned outages."

Question(s):

a) Please confirm that the Turbine Rotor Replacement for one Darlington unit will be completed outside of the 2026-2031 rate term. If confirmed, please identify which unit and indicate whether the work will take place during the unit's planned outage, as will be the case for the other units. Otherwise, please explain.

E2-Staff-159

Ref 1: Exhibit E2 / Tab 1 / Schedule 2 / p. 4

Preamble:

At Reference 1, the a state that "during the same Unit 2 Darlington Primary Moisture Separators (PMS) replacement outage in 2027, OPG will execute the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project that was deferred from 2025".

Question(s):

a) Please elaborate on why the Unit 2 Turbine Control and Auxiliary Systems Upgrade project was deferred from 2025 to 2027.
b) Please confirm that OPG plans to commence and complete the Unit 2 Turbine Control and Auxiliary Systems Upgrade during the Unit 2 Darlington PMS replacement outage in 2027 (i.e. that the upgrade will not involve outage time beyond the time for an already planned outage). Otherwise, please explain.

EXHIBIT F – OPERATING COSTS

F1-Staff-160

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 25 Chart 8

Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 29
Ref 3: EB-2020-0290 Exhibit A1 / Tab 3 / Schedule 2 Attachment 1 p. 1
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 Attachment 4
Ref 5: Exhibit A2 / Tab 1 / Schedule 1 Attachment 4

Preamble:

At Reference 1, OPG states that the Equivalent Forced Outage Rate is 6.7% in 2019.

At Reference 3, OPG states that the Equivalent Forced Outage Rate is 6.4% in 2019 in the Performance Scorecard.

At Reference 2, OPG states that the Total Generation Cost is $23.6/MWh in 2018.

At Reference 3, OPG states that the Total Generating Cost is $23.4/MWh in 2018 in the Performance Scorecard.

At Reference 4, OPG states that the Availability Factor for Hydroelectric is 85.2% in 2024 in the Performance Scorecard.

At Reference 5, OPG states that the Hydroelectric Availability is 85.8% in 2024 in the Financial Summary.

Question(s):

a) Please confirm the numbers of the reported hydroelectric performance metrics in the current application for the years 2018 and 2019. If confirmed, please explain the change in amounts between the EB-2020-0290 reporting and the EB-2025-0297 reporting for the metrics. If not confirmed, please revise the numbers reported in the current application.
b) Please confirm that the Hydroelectric Availability referenced in the Financial Summary at Reference 5 is the same metric as the Hydroelectric Availability referenced at Reference 4. If confirmed, please revise the values in Exhibit A2-1-1 and Exhibit A1-3-2. If not confirmed, please explain the difference in calculating the two metrics. If providing this explanation, please provide the formula for each metric.

F1-Staff-161

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 28 Chart 10

Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 30 Chart 12

Preamble:

At Reference 1, OPG shows its OM&A Unit Energy Cost did not meet the target values as per Business Plan in the years of 2018, 2019, 2021, 2022 & 2023.

At Reference 2, OPG shows an approximate 43% increase in the three-year rolling average of the Total Generating Cost between 2016 and 2024.

Question(s):

a) Please explain the relationship between Unit Energy Cost and Total Generating Cost. Please confirm that Unit Energy Cost is a key driver to Total Generation cost. If not confirmed, please explain.
b) Please outline the strategies OPG intends to implement to better align its cost-effectiveness performance with Business Plan targets.

F1-Staff-162

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 22 Chart 6
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 30 Chart 8

Preamble:

At Reference 1, OPG shows its Hydroelectric Availability factors in 2023 & 2024 are below business targets.

At Reference 2, OPG shows its Equivalent Forced Outage Rates (EFOR) has never met its business targets since 2016.

Question(s):

a) Given the underperformance against the business targets in EFOR, as well as the emerging unfavorable trend in Hydroelectric Availability, please outline the strategies OPG intends to implement to better align its system reliability performance with Business Plan targets.

F1-Staff-163

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 20

Preamble:
At Reference 1, OPG states that Total Recordable Environmental Events will replace the Environmental Performance Index in 2026. This change removes the Polychlorinated Biphenyl equipment removal program due to the program finishing.

Question(s):

a) Please confirm that the current Environmental Performance Index is the sum of Polychlorinated Biphenyl equipment removal incidents, spills, and regulatory infractions, while its replacement Total Recordable Environmental Events includes only spills and regulatory infractions.

F1-Staff-164

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 5

Preamble:

At Reference 1, OPG states that hydroelectric overhaul projects are typically required every 25-30 years and involve significant OM&A maintenance activities. Refurbishment projects are capital investments aimed at extending useful life of the equipment.

Question(s):

a) Please explain whether all overhaul project costs are expensed as OM&A (i.e. no capitalized costs), and whether the costs are included as base OM&A, project OM&A, or a combination both.
b) Please clarify whether refurbishment projects incur OM&A. If yes, please clarify whether the refurbishment-related OM&A is included as base OM&A, project OM&A, or both.

c) Please provide 2016-2027 actual and budgeted and/or planned overhaul project OM&A by year.
d) If applicable, please provide 2016-2027 actual and budgeted planned refurbishment project OM&A by year.

F1-Staff-165

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that one of the cornerstones of the Renewable Generation Programmatic Collaboration Agreement (RG PCA) initiative is to facilitate early Original Equipment Manufacturers (OEM) engagement. Each OEM has been allocated a group of refurbishment projects for various stations and units, with assignments based on work continuity and geographical proximity (such as shared river systems) to support more consistent project execution and efficient use of resources.

Question(s):

a) For the RG PCA initiative, please explain how OPG allocates common costs to regulated and unregulated hydroelectric businesses.

F1-Staff-166

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 24

Preamble:

At Reference 1, Chart 7 – Regulated Hydroelectric Availability (%, 2025-2031 Targets) sets out all 54 regulated hydroelectric stations' Availability forecast in 2025-2031.

Question(s):

a) OEB staff notes the Availability forecast is trending lower in 2027 throughout 2031 (i.e. 83.7% - 84.9%), compared to historical years and the 2025-2026 forecast values (i.e., 87.4% - 89.2%). To what extent is the lower forecast due to an expected increase in station project work in 2027-2031?

F1-Staff-167

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 8 / p. 25
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / p. 26

Preamble:

Reference 1 shows that OPG has missed its Equivalent Forced Outage Rate (EFOR) target in all years from 2016 to 2024 (i.e. EFOR was higher than target).

At Reference 2, OPG states that the forecasted outage plan for each station accounts for the influence of planned outages on estimated operating hours. Operating hours are estimated using the planned outage schedule, projected forced outage hours, and available but not operating hours. These estimated operating hours provide the foundation for establishing EFOR performance targets.

Question(s):

a) Please explain whether the 2016-2024 missed targets are due to actual planned outage work being ahead of schedule, changes to the scope of planned outage work, or neither.
b) Please explain why there were higher than planned outage activities in 2016-2024.

F1-Staff-168

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 12 / p. 29

Preamble:

At Reference 1, the chart illustrates the Total Generating Cost metric performance in 2016-2024.

Question(s):

a) Please provide the Total Generating Cost forecasts and targets for 2016-2024, if they exist. If they do not exist, please explain why not.
b) Please provide the Total Generating Cost forecasts and targets for 2025-2027. If they do not exist, please explain why not.

F1-Staff-169

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F1 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, the Operating Costs Summary - Regulated Hydroelectric ($M) table provides Base and Project OM&A in 2016-2027.

At Reference 2, the Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) table provides FTEs in 2016-2019.

At Reference 3, the Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) table provides FTEs in 2020-2031.

OEB staff created the following table based on the information in the references:

Table 1 – OM&A and FTE increase comparison

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Base OM&A ($ millions) - Ref 1 table Line No. 1	204.52	205.42	215.47	236.47	251.16	264.26	274.16	286.22
Project OM&A ($ millions) -	53.55	81.11	74.10	75.26	68.32	92.63	90.48	126.97

Ref 1 table Line No. 2								
Subtotal	258.08	286.53	289.57	311.73	319.48	356.89	364.64	413.19
Year-Over-Year increase in OM&A		**11.02%**	1.06%	**7.65%**	2.49%	**11.71%**	2.17%	**13.31%**
Regulated Hydroelectric OM&A FTEs - Ref 3 table Line No. 6	899.2	882.4	905.5	931.8	978.6	1051.6	1075.0	1074.0
Year-Over-Year increase in OM&A FTEs	N/A	**-1.87%**	2.62%	**2.91%**	5.02%	**7.46%**	2.23%	**-0.09%**

Question(s):

a) Please provide FTE breakdowns into OM&A and Capital in 2016-2019 as shown in the table in Reference 2 above.
b) OEB staff notes the year-over-year increase in OM&A is much higher than the year-over-year increase in OM&A FTEs in 2021, 2023, 2025 and 2027 (i.e. % bolded in Table 1). Please provide any non-compensation cost drivers that result in Base and Project OM&A increases in 2021, 2023, 2025 and 2027.

F1-Staff-170

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 6
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Chart 8
Ref 3: Exhibit E1 / Tab 1 / Schedule 1 / Table 1

Preamble:

Reference 1 presents historical hydroelectric availability for the 12 hydroelectric generating stations that OPG states have a substantial influence on fleet-wide results.

Reference 2 presents the historical equivalent forced outage rate for the same 12 generating stations.

Question(s):

a) For each of Reference 1 and Reference 2, please confirm whether there are any stations other than those identified in the Charts that have a substantial influence on each of the Regional results of historical hydroelectric availability or the results of historical equivalent forced outage rate. If yes, please identify them.
   i. For any stations identified in part a) please include them in the responses to parts d) and e)

b) Please provide a mathematical example of how hydroelectric availability is calculated.

c) Please provide a mathematical example of how equivalent forced outage rate is calculated

d) Please update Reference 1 for 2025 actual results, and the hydroelectric availability from the 2026 and 2027 forecasts presented in Reference 3. Please provide the table in excel format.

e) Please update Reference 2 for 2025 actual results, and the equivalent forced outage rate from the 2026 and 2027 forecasts presented in Reference 3. Please provide the table in excel format.

F1-Staff-171

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 tables
Ref 2: Exhibit F1 / Tab 2 / Schedule 1 tables
Ref 3: Exhibit F2 / Tab 1 / Schedule 1 tables
Ref 4: Exhibit F2 / Tab 2 / Schedule 1 tables
Ref 5: Exhibit F2 / Tab 2 / Schedule 2 tables
Ref 6: Exhibit F2 / Tab 3 / Schedule 1 tables
Ref 7: Exhibit F2 / Tab 3 / Schedule 2 tables
Ref 8: Exhibit F2 / Tab 4 / Schedule 1 tables
Ref 9: Exhibit F2 / Tab 4 / Schedule 2 tables
Ref 10: Exhibit F2 / Tab 5 / Schedule 1 tables
Ref 11: Exhibit F2 / Tab 5 / Schedule 2 tables
Ref 12: Exhibit F2 / Tab 7 / Schedule 1 tables

Preamble:

The tables referenced above provide 2025 budget numbers.

Question(s):

a) Please update the references above to include 2025 year-end actual numbers.

F1-Staff-172

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, OPG states that the budgeted 2025 regulated hydroelectric regular and non-regular FTEs are 1,428.3, an increase from the 2024 actual of 1,236.6.

Question(s):

a) Please provide the actual regulated hydroelectric FTE number at December 31, 2025.

F1-Staff-173

Ref 1: Exhibit F1 / Tab 2 / Schedule 1 / p. 2

Preamble:

At Reference 1, OPG states that the total Base OM&A expenses increased in 2022 to 2024 reflecting labour cost escalation as a result of collective bargaining.

Question(s):

a) Please provide the contribution of compensation costs to each of 2022-2027's Base OM&A increase, breaking down the amounts attributable to wage escalation as a result of collective bargaining, to the hiring of new FTEs, and to any other sources.

F1-Staff-174

Ref 1: Exhibit F1 / Tab 3 / Schedule 1 / pp. 1 & 3

Preamble:

At Reference 1, OPG is requesting a project OM&A increase of $46.8 million from the annual average of the 2022-2026 term of $80.2 million, to reflect the increased project OM&A portfolio necessary to maintain aging assets. OPG states that overhaul projects are generally performed every 25-30 years. OPG plans to progress approximately 20 overhaul projects in support of the turbine-generator refurbishment program in the test year.

Question(s):

a) Please clarify if overhaul projects are considered a stand-alone project with separate OM&A cost tracking, or if they form a part of the turbine-generator refurbishment project. Please confirm that costs will be assessed (i.e. capitalized or expensed) according to OPG's capitalization policy.
b) Given the significant term-over-term increase in project OM&A, please confirm that, in 2013-2026, OPG did not change its methodology for classifying overhaul project costs as OM&A.
c) Please provide an approximate breakdown of the $46.8 million increase, showing the amount attributable to market/inflationary-related increases and the amount attributable to an increase in the number of projects in the OM&A portfolio.

F1-Staff-175

Ref 1: Exhibit F1 / Tab 3 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that it is required to spend significant effort and funding to mitigate the impacts of Alkali-Aggregate Reaction, which has led to increased Project OM&A expenditures.

Question(s):

a) Given there are 30 concrete restoration initiatives in the 2027 test year, please clarify whether the Alkali-Aggregate Reaction concrete mitigation costs are all treated as project OM&A or if they also appear elsewhere in the OM&A and capital budgets.
b) Please provide the Alkali-Aggregate Reaction concrete mitigation-related OM&A expenditures in 2022-2025 (actual) and 2026-2027 (budget and plan), by year.

F1-Staff-176

Ref 1: Exhibit F1 / Tab 4 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that it holds a lease agreement with the St. Lawrence Seaway Management Corporation. The current 30-year lease is in place until 2038, with rates subject to review every five years. The water conveyance payment terms are currently in legal arbitration.

Question(s):

a) Please clarify when the existing rates expire and provide an update on the rates review.

F1-Staff-177

Ref 1: Exhibit F1 / Tab 5 / Schedule 1 / p. 1

Preamble:

At Reference 1, OPG states that the OM&A purchased services expenditures during the historical period (2016-2024) were $57.1 million in 2016, $53.2 million in 2017, $57.1 million in 2018, $56.5 million in 2019, $49.9 million in 2020, $64.7 million in 2021, $78.3 million in 2022, $80.2 million in 2023, and $71.4 million in 2024.

Question(s):

a) Please explain the increase in purchased services expenditure since 2020. Please provide an estimate of the extent to which the increase is due to purchased services scope change or market/inflationary-related increase. If other factors contributed to the increase, please explain and estimate their contributions.

F2-Staff-178

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 1 / pp. 1-6
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / pp. 27-32 (Section 3.4.2)

Preamble:

At Reference 1, OPG describes the results of three prior gap closure initiatives (Right Work, Right Time, Right Value; Leaders Driving Business Results; People Powering the Future) using qualitative descriptions and operational metrics such as backlog reductions and work protection index trends, but does not quantify the OM&A cost savings or cost avoidances attributable to these initiatives.

At Reference 2, OPG describes five current fleetwide improvement initiatives for the 2025-2031 Business Plan in similar qualitative terms, with anticipated results described as expected improvements in operational metrics rather than dollar-value cost impacts.

Question(s):

a) For each of the three prior gap closure initiatives described in Attachment 1, please quantify the annual OM&A savings or cost avoidances (in $ millions) achieved in each year from 2022 to 2025. If OPG has not tracked the financial impact of these initiatives separately, please explain why not and how OPG assesses whether its gap-based business planning process is delivering measurable cost benefits for ratepayers.

b) For each of the five current fleetwide improvement initiatives described in Section 3.4.2, please provide: (a) the estimated annual cost to implement each initiative over the IR term, and (b) the projected annual OM&A savings or cost avoidances expected from each initiative, expressed in dollar terms.

F2-Staff-179

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 / pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / pp. 26-27 (Section 3.3)

Preamble:

At Reference 1, Darlington's non-normalized Non-Fuel Operating Cost per MWh target is $66.61 for 2027, which is more than double the industry median of $24.64 and more than triple the best quartile of $19.64. The normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW Design Electrical Rating (DER) targets for 2027-2031 are all marked N/A. Note 6 to Chart 4 states that "Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

At Reference 2, OPG attributes elevated Darlington Total Generating Cost per MWh during the IR term to higher project-related investments, reduced generation from the Vacuum Building Outage in 2027, and emergent work associated with the Primary Moisture Separator Replacements and Turbine Rotors Replacement but does not disaggregate the cost impact of these individual factors.

Question(s):

a) Please provide normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW DER targets for each year of the IR term. If they are not available, please explain.
b) Please provide a breakdown of the Darlington Non-Fuel Operating Cost per MWh target of $66.61 for 2027 into its major cost components (e.g., base OM&A, outage OM&A, project OM&A, support services allocations), and for each component identify the gap to the industry median.
c) Note 6 to Chart 4 states that Value for Money targets are "indicative." Please confirm when final Value for Money targets will be established. If the targets have since been established, please provide them.

F2-Staff-180

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that the previous staff benchmarking studies included external purchased services (managed tasks), which are excluded from the current study due to the self-reported nature and data visibility from benchmarked peers.

Question(s):

a) Please provide the external purchased services FTE number that otherwise would be included in the current study for 2024 year.

F2-Staff-181

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 12
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p. 1

Preamble:

At Reference 1, OPG states that 4,458 OPG Nuclear staff were benchmarked and 2,386 were excluded from benchmarking consistent with the methodology applied in prior studies. The information is as of December 2024. OEB staff infer from these two values that the number of OPG Nuclear staff in 2024 was 6,844.

Reference 2 states that the number of direct nuclear facilities FTEs in 2024 was 7,507.3.

Question(s):

a) Please reconcile the difference between the value inferred by OEB staff from Reference 1 with the value at Reference 2.

F2-Staff-182

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 2 - Comparison of OPG Nuclear Performance to Industry Benchmarks, p. 14

Preamble:

At Reference 1, there are eight metrics under the Reliability area, nine metrics under the Value for Money area and one metric under the Human Performance area.

Question(s):

a) Please clarify whether Darlington's best-quartile performance in 2023 on six of the Reliability metrics reflects any benefit of the completed refurbishments as of that time.
b) Please clarify whether Darlington's below median and below third quartile performance in 2023 on most Value for Money metrics is expected to improve post refurbishment.

F2-Staff-183

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 3 - Annual Operational and Financial Targets for Pickering, pp. 20-22

Preamble:

At Reference 1, most metric target settings under Value for Money area are unavailable in Chart 3. Note 6 states "the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

Question(s):

a) Please provide the annual targets for the Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

F2-Staff-184

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 23

Preamble:

At Reference 1, Darlington’s annual target is set as 0.0005 throughout 2031 on the Fuel Reliability (microcuries per gram) metric under Safety.

At Reference 1, Darlington’s annual target is set as 0.50 throughout 2031 on the Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric under Safety.

Question(s):

a) Please confirm if a higher value in Fuel Reliability (microcuries per gram) metric means a lower performance, and that the annual target at 0.0005 means Darlington’s performance would be expected to be below the third quartile throughout 2031.
b) Please confirm if a higher value in Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric means a lower performance, and that the annual target at 0.50 means Darlington’s performance would be expected to be below the third quartile throughout 2031.
c) Please explain if the above-mentioned two metrics’ performance are expected to improve to the third quartile or better beyond 2031.

F2-Staff-185

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, p. 24

Preamble:

At Reference 1, Darlington’s annual target is set as 95.3-96.8 throughout 2031 on the Unit Capability Rate (%) metric under Reliability.

Question(s):

a) Please confirm if a lower value in Unit Capability Rate (%) metric means a lower performance, and that the annual target at 95.3-96.8 means Darlington station's performance would be expected to be below the third quartile throughout 2031.
b) Please explain if the Unit Capability Rate (%) metric's performance is expected to improve to the third quartile or better beyond 2031.

F2-Staff-186

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / p. 10

Preamble:

At Reference 1, there are eleven metrics under the Value for Money area, and nine metrics have annual targets in 2025-2031.

At Reference 1, two targets under Value for Money in 2027-2031 are unavailable in Chart 4. Note 6 says that the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application.

At Reference 2, OPG states that in the case of Darlington, this (refresh) analysis included costs associated with units in Refurbishment. Since 2017, OPG has calculated an adjustment for refurbishment costs based on the previously established methodology that continues to be applied until the Darlington Refurbishment Program (DRP) is completed.

Based on the References, OEB staff produced Table 1, comparing the original and updated normalization methodologies.

Table 1 – Comparison of Normalized Total Generating Cost (TGC) Methodologies ($/MWh)

	2027	2028	2029	2030	2031
Normalized Total Generating Cost per MWh – Updated Methodology	**51.58**	41.14	42.21	39.14	34.68

Normalized Total Generating Cost per MWh – Original Methodology	**81.36**	50.7	55.08	48.74	44.08
Difference between the original and updated methodology	**-29.78**	-9.56	-12.87	-9.6	-9.4

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.
b) Please confirm that the updated normalization methodology in annual TGC calculation does not include any refurbishment costs beyond 2026.
c) Please explain why the Normalized TGC/MWh metric value differs significantly in 2027 between the original methodology and updated methodology.
d) Please provide the 2027-2031 annual targets for the two Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

F2-Staff-187

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 33
Ref 2: Exhibit F2 / Tab 2 / Schedule 2 / pp. 3-4
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / pp. 52-53

Preamble:

At Reference 1, OPG states that it records, in the Pickering B Variance Account, the revenue requirement impact resulting from actual capital and non-capital costs incurred for extension activities. The Pickering B Variance Account also allows OPG to record costs incurred for preserving resources and supporting infrastructure to enable potential refurbishment and subsequent operation of the Pickering units beyond September 30, 2026.

At Reference 2, OPG states that planned Base OM&A costs in 2026 are $1,210.2 million, which is $588.5 million or 94.7% higher than the 2026 OEB-approved budget of

$621.7 million. The reportable variances are largely due to Pickering Units 5-8 not ending commercial operation in 2025 as was assumed in EB-2020-0290.

Reference 3 describes and details the Pickering B Variance Account.

Question(s):

a) Please provide, for the increased base OM&A costs in 2026 (i.e. $588.5 million or 94.7% higher than the 2026 OEB-approved budget of $621.7 million) the level of costs that would be recovered through additional revenues generated from the output of Pickering Units 5-8 during the period from January 1, 2026-September 30, 2026.

F2-Staff-188

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 36
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, OPG states that historical and bridge year amounts, identified in Reference 2 at Line 9, primarily relate to preparation for potential new nuclear generation. These costs are being recorded in the Nuclear Development Variance Account.

At Reference 2, Line 9 shows the 2025 budget amount at $62.1 million and 2026 budget amount at $136.4 million.

Question(s):

a) Please provide the 2025 actual amount for Other New Nuclear OM&A.

F2-Staff-189

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 8

Preamble:

At Reference 1, the table provides a list of job function categories that were excluded from the 2024 OPG nuclear staffing benchmarking methodology.

Question(s):

a) How many FTEs are in each of the excluded categories?

F2-Staff-190

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 11
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6

Preamble:

At Reference 1, Indeavor states that data provided at the Electric Utility Cost Group (EUCG) Account level was normalized using historical ratios to split the EUCG account groups into the respective Indeavor functions.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: Please confirm that the normalization methodology described at Reference 1 is the same as that followed by Goodnight Consulting at Reference 2? If not confirmed, please explain.

F2-Staff-191

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 21
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6, p. 9

Preamble:

At Reference 1, Indeavor provides a list of job functions in the 2024 OPG nuclear staffing benchmarking.

At Reference 2, Goodnight Consulting provides a list of job functions in the 2019 OPG nuclear staffing benchmarking.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: OEB staff compared the job functions in Indeavor's 2024 benchmarking and in Goodnight Consulting's 2019 benchmarking. Please explain the following differences:
   i. The "Information Technology" function is in the 2024 benchmarking but is not in the 2019 benchmarking,
   ii. The "Security Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking,
   iii. The "Management Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking.

F4-Staff-192

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p. 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a
Ref 3: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

Reference 1 shows nuclear facilities, DNNP LP, and hydroelectric regulated facilities FTEs for 2020-2031, broken down according to direct vs allocated.

Question(s):

a) For each of nuclear facilities, DNNP LP, and hydroelectric regulated facilities, please show how many of the allocated FTEs are treated as capital vs. OM&A for 2026-2031.

F2-Staff-193

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, the table shows nuclear facilities FTE information.

Question(s):

a) Please explain the difference in classification between "Term and Extended Temporary" staff and "Temporary" staff.
b) Please explain what the OPG Nuclear Non-Energy Direct staff covers (lines 41, 42, 43 and 44).

F2-Staff-194

Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2b

Preamble:

References 1 and 2 set out Base OM&A by resource type for OPG's nuclear facilities and for the Darlington New Nuclear Program (DNNP) facilities, respectively.

Question(s):

a) Please provide a few examples of the types of costs in the Other Purchased Services category and explain why Other Purchased Services makes up a higher percentage of Base OM&A for the DNNP facilities than for the OPG nuclear facilities.
b) Please provide the quantum of contracted labour costs to be procured through Other Purchased Services for the DNNP facilities in 2027-2031.

F2-Staff-195

Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Attachment 1, p. 7
Ref 2: Exhibit F1 / Tab 2 / Schedule 1 / Attachment 1, p. 7

Preamble:

At Reference 1, OPG states that Renewable Generation Operations functions provide support for the Nuclear fleet, such as Energy Markets, with costs shown in Nuclear Base OM&A actuals and plan.

At Reference 2, OPG states that the Energy Markets team offers and optimizes OPG's generation assets in the IESO-administered electricity market, ensuring compliance with all legal, regulatory, environmental, and operational requirements.

Question(s):

a) Please provide, for each of 2027-2031, the amount of Renewable Generation Operations support costs allocated to Nuclear Base OM&A.
b) Please confirm that the historical and 2027 Renewable Generation Operations support costs that are allocated to Nuclear Base OM&A were not also allocated to the Hydroelectric businesses' revenue requirements. If not confirmed, please explain.

F2-Staff-196

Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 1a
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Base OM&A - OPG Nuclear Facilities table shows that the total Base OM&A increases from $840.4 million in 2027 to $1,225.4 million in 2031.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increases from 3,283.9 in 2027 to 3,882.6 in 2031.

At Reference 3, the Base OM&A - OPG Nuclear Facilities ($M) resource type table shows labour costs (Labour, Non-Regular Labour, Overtime and Augmented Staff) in Base OM&A.

Using the information in the References, OEB staff produced following table:

Table 1 – Base OM&A Change 2027-2031

	2027	**2031**	**% change**
Nuclear Facilities OM&A (excluding DNNP Facilities) FTE count - Ref 2 Line 6	**3,283.9**	**3,882.6**	**18.23%**
Labour ($ millions) - Ref 3 Line 1	570.03	860.12	50.89%
Non-Regular Labour ($ millions) - Ref 3 Line 2	10.07	10.36	2.81%
Overtime ($ millions) - Ref 3 Line 3	36.42	61.62	69.20%
Augmented Staff ($ millions) - Ref 3 Line 4	1.53	1.33	-12.78%
Sum of Labour costs within Base OM&A ($ millions):	**618.05**	**933.43**	**51.03%**
Total Base OM&A ($ millions)- Ref 1 Line 15	**840.4**	**1,225.4**	**45.80%**

Question(s):

a) Please confirm that the four categories of labour listed in Table 1 reflect all labour costs within Base OM&A. If not confirmed, please explain.
b) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.
c) Please explain why the increase in the sum of labour costs (i.e., 51.03%) is higher than the increase in FTE counts (i.e. 18.23%) between 2027 and 2031.
d) Please provide any non-compensation cost drivers which contribute to the total Base OM&A costs increase (i.e. 45.8%) from 2027-2031.

F2-Staff-197

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, the Operating Costs Summary - OPG Nuclear Facilities ($M) table shows the Nuclear Facilities OM&A (excluding Darlington New Nuclear Program (DNNP) Facilities).

Question(s):

a) Please provide the planned external purchased service costs in 2027-2031 in the following OPG Nuclear Facilities OM&A categories:
   i. OPG Nuclear Facilities Base OM&A,
   ii. OPG Nuclear Facilities Project OM&A
   iii. Pickering Cyclical Maintenance OM&A,
   iv. Pickering Refurbishment OM&A

F2-Staff-198

Ref 1: Exhibit F2 / Tab 2 / Schedule 2 / p. 2
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that Planned Base OM&A costs in 2029 are $898.4 million, which is $47.8 million or 5.6% higher than the 2028 planned Base OM&A costs of $850.7 million. The higher OM&A costs include the impact of the 53rd fiscal week in 2029.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increase from 3,246.8 in 2028 to 3,317.7 in 2029.

OEB staff calculates that, at Reference 3, labour categories (Labour, Non-Regular Labour, Overtime and Augmented Staff) make up 75.2% of Base OM&A costs in the IR term.

OEB staff also calculates that the 53rd fiscal week, combined with the increase in FTEs could be expected to cause an increase in Base OM&A of approximately 3% between 2028 and 2029. That is:

- 53rd Fiscal Week adds approximately 2% (due to one extra week of compensation costs 1/52=2)
- OPG's projected FTE count increase adds approximately 2.1% (3,317.7/3,246.8 – 100%=2.1% compensation costs increase)

Applying the 2.0 + 2.1% increase to the labour categories' 75.2% contribution to Base OM&A results in an increase of approximately 3% in 2029 compared to 2028.

Question(s):

a) Please comment on the reasonableness of OEB staff's calculation that 2029 Base OM&A could be expected to be 3% higher than 2028 Base OM&A.
b) Please provide the 2028 to 2029 annual wage escalation and general inflation assumed in the Planned Base OM&A which results in the 5.6% Base OM&A costs increase from 2028 to 2029.

F2-Staff-199

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table breaks out the FTEs accounted as OM&A and accounted as Capital.

Question(s):

a) Please provide the FTEs split between OM&A and Capital in Darlington Refurbishment Program's FTEs.

b) Please provide the FTEs split between OM&A and Capital in Pickering Refurbishment Program's FTEs.
c) Please provide the FTEs split between OM&A and Capital in Nuclear Provision FTEs.

F2-Staff-200

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

At Reference 2, the Regular and Non-Regular (FTEs) - DNNP Facilities table shows the DNNP Facilities OM&A Staff FTEs number.

OEB staff created the following table to compute year over year changes to DNNP staffing across 2027-2031.

Table 1 – DNNP Facilities OM&A Year over Year

	2027	**2031**	**YoY % change**
DNNP Facilities OM&A ($ millions) - Ref 1 table Line No. 4	50.2	167.6	**233.86%**
DNNP Facilities OM&A Staff FTEs number - Ref 2 table Line No. 6	144.9	238.5	**64.60%**

Question(s):

a) Please confirm that the values calculated in Table 1 are correct. If not confirmed, please provide the corrected values.
b) Please provide any non-compensation cost drivers that lead to the DNNP Facilities OM&A ($ millions) increase.

F2-Staff-201

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

Question(s):

a) Please provide the external purchased service costs treated as DNNP Facilities OM&A in 2026-2031, with breakdowns into Base, Outage and Operational Readiness OM&A.

F2-Staff-202

Ref 1: Exhibit F2 / Tab 3 / Schedule 1 / Table 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Project OM&A Summary - OPG Nuclear Facilities ($M) table shows the 2020-2031 Project OM&A.

At Reference 2, the Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table shows the 2020-2031 OPG Nuclear Facilities Capital FTEs.

OEB staff created the following table showing year over year changes to OM&A.

Table 1 – Nuclear Facilities OM&A Year over Year

	2024	**2025**	**YoY % Change**

Total Project OM&A - OPG Nuclear Facilities (excluding Darlington New Nuclear Program (DNNP) Facilities) ($ millions) - Ref 1 table Line No. 16	107.9	75.6	**-29.94%**
OPG Nuclear Facilities Capital (excluding DNNP Facilities) FTEs - Ref 2 table Line No. 12	324.3	517.3	**59.51%**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide corrected values.
b) Please provide 2025 actual Project OM&A as presented in the Reference 1 table if available.
c) Please explain why the Project OM&A costs trend down from 2024 to 2025 by 29.94% while the OPG Nuclear Facilities Capital FTEs sees an increase from 2024 to 2025 of 59.51%. To what extent is the difference in trends due to more project costs being capitalized rather than being expensed as OM&A?
d) Please clarify if OPG's capitalization policy on project costs has changed in the 2024-2025 period.

F2-Staff-203

Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / page 3

Preamble:

At Reference 1, the Comparison of Project OM&A - OPG Nuclear Facilities ($M) table lays out the 2020-2026 Project OM&A Actual/Budget vs. OEB-Approved difference.

At Reference 2, OPG states that planned project OM&A costs for 2027-2031 are $410.6 million. This value is $76.9 million (16%) lower than the actual expenditure amount of $487.4 million in the 2022-2026 term (2025 and 2026 being forecast). This decrease is primarily driven by decreased planned expenditures in Project OM&A (Portfolio) of $11.7 million and Non-Portfolio Projects of $65.2 million.

OEB staff created the following table showing Project OM&A year over year trends.

Table 1 – Project OM&A Year over Year

	2022	**2023**	**2024**	**2025**	**2026**	**2022-2026 term**
Total Project OM&A Including Adjustments ($ millions) - Actual - Ref 1 table Line No. 18, Actual columns	89.5	141.1	107.9	75.6	73.3	487.4
Total Project OM&A Including Adjustments ($ millions) - OEB-Approved - Ref 1 table Line No. 18, OEB-Approved columns	86.4	82.5	76.6	72.8	60.1	378.4
Project OM&A Actual over OEB-Approved ($ millions)	3.1	58.6	31.3	2.8	13.2	**109.0**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.
b) Given the forecasted decrease in project OM&A in 2027-2031 term compared to 2022-2026 actual, please explain if the $109 million over OEB-Approved spending on project OM&A in 2022-2026 is due to pacing of 2022-2026 projects going ahead of original schedule, project OM&A scope change, or neither. If neither, please explain.
c) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain

F2-Staff-204

Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / p. 1
Ref 3: Exhibit F2 / Tab 3 / Schedule 3 / Table 4

Preamble:

Reference 1 states at line 24 that the 2027-2031 Plan for Portfolio Projects (Unallocated) is $152.6 million.

Reference 2 states that Portfolio Projects (Unallocated) is "the remaining budget available to cover the cost of projects that are progressing through the review and approval process but do not have a PMOC-approved budget or an approved BCS."

References 3 lists unallocated OM&A projects.

Question(s):

a) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain.
b) For the projects at Reference 3, are there business cases or similar documentation that supports the project need and cost estimates? If so, please provide them for those projects greater than $20 million. If not available, please describe the information provided to the business unit asset management governing body.

F2-Staff-205

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that Darlington station has a 36-month planned "cyclical outage" schedule. OPG states that non-refurbishment work conducting on units during their refurbishment “effectively replaces” cyclical outages that would have otherwise been undertaken.

Reference 2 shows Outage OM&A for 2020-2031.

Question(s):

a) Please confirm that, for 2022-2026, the Darlington non-refurbishment “cyclical outage” OM&A is included under “Darlington Outages” in Reference 2.

F2-Staff-206

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 1-2

Preamble:

At Reference 1, OPG states that Darlington New Nuclear Program (DNNP) facilities’ refueling outages will initially be performed on a 12-month cycle followed by 24-month cycles. Pickering station has a 30-month planned outage schedule. Darlington station has a 36-month planned outage schedule.

Question(s):

a) Please clarify if the 24-month outage cycle cadence for DNNP is expected for the duration of the facility’s life.
b) Please explain how OPG plans outage schedules efficiently to maximize utilization of outage OM&A resources.

F2-Staff-207

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that the Pickering Cyclical Maintenance program will primarily be executed by existing OPG operational staff.

Question(s):

a) Given that the Pickering Cyclical Maintenance is a new category in OPG's 2026-2031 OM&A budget, please provide the number of existing FTEs and any new hire FTEs whose costs will be accounted in Pickering Cyclical Maintenance OM&A in 2026-2031.

F2-Staff-208

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 4-5
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that both Base OM&A and Pickering Cyclical Maintenance OM&A resources are required to carry out the ongoing inspection, maintenance and regulatory compliance activities at Pickering during the four-unit refurbishment outage.

At Reference 2, the Outage OM&A table (line 1 and 2) shows that Darlington recorded Outage OM&A during its refurbishment years (2020-2026). The table (line 4 and 5) also shows that Pickering will have zero Outage OM&A planned during its refurbishment years (2027-2030).

Question(s):

a) Please clarify if the Pickering Cyclical Maintenance OM&A is a re-classification of costs that would otherwise be recorded under Base OM&A and Outage OM&A.
b) Please explain if and why Outage OM&A definition is applied differently for Darlington station and Pickering station during their respective refurbishment years.

F2-Staff-209

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 6

Preamble:

At Reference 1, OPG states that the completion of specific outages requires both base resources and incremental resources. Labour resources are captured in Base OM&A.

The incremental resource types associated with resources utilized during outages include:

- Non-Regular Labour: additional non-regular staff directly supervised by OPG staff (typically trade workers such as electricians).
- Overtime: regular and non-regular staff working on overtime in support of outage execution.
- Augmented Staff: contractors directly supervised by OPG staff (typically engineers and assessors).

Question(s):

a) Does OPG pay Augmented Staff (contractors) overtime? In general, what is the labour cost differential between utilizing OPG staff to work overtime during outages vs. using contractors?

F2-Staff-210

Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that the actual outage OM&A costs also include unbudgeted planned outages.

Question(s):

a) Please clarify if “unbudgeted planned outages” includes planned but under-budgeted outages.

F2-Staff-211

Ref 1: Exhibit F2 / Tab 5 / Schedule 2 / Table 1a and 1b
Ref 2: Exhibit F2 / Tab 5 / Schedule 1 / p. 1

Preamble:

At Reference 1, the Comparison of OPG Nuclear Facilities Fuel Costs ($M) tables provide the OEB approved, Actual and Budget fuel costs in 2022-2026.

At Reference 2, OPG states that its average price of manufactured nuclear fuel bundles loaded into a CANDU reactor has increased since EB-2020-0290 and this trend is expected to continue over the IR term.

OEB staff created the following table showing the trends in fuel costs:

Table 1 – Fuel Costs ($ millions)

	2022	**2023**	**2024**	**2025**	**2026**
OPG Nuclear Facilities Fuel Costs - Ref 1 table Line No. 8 and 15/16, Actual / Budget columns	222.5	218.4	211.8	255.1	239.2
OPG Nuclear Facilities Fuel Costs - Ref 1 table Line No. 8 and 15/16, OEB-Approved columns	177.3	181.3	209.5	189.9	148.0
Fuel costs over the OEB Approved amount	45.3	37.1	2.3	**65.2**	**91.2**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.
b) Please clarify if the price of manufactured nuclear fuel bundles is hedged for the near term or not.

c) As shown in Table 1, the 2025 and 2026 budgeted fuel costs are higher than the OEB-Approved amounts. Please explain the degree to which the difference is due to fuel price increases, higher energy production, or other factors.
d) Please provide the 2025 actual fuel costs, if available.

F2-Staff-212

Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that since EB-2020-0290, OPG has increased the fuel procurement planning timeframe from five years to 15 years, due in part to market drivers such as increasing nuclear power demand, and supply and demand dynamics expected in the global uranium market.

Question(s):

a) Please provide the increased annual working capital amount arising from the extension of the fuel procurement planning timeframe from five years to fifteen years.

F2-Staff-213

Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / pp. 12-13

Preamble:

At Reference 1, OPG states that given the observed increase in uranium price volatility and the elevated risk of continued cost increases during this IR term, OPG has relied on UxC’s High-Price Midpoint curve instead of the Mid-Price Midpoint curve used in EB-2020-0290.

Question(s):

a) Please provide the forecasted fuel costs in 2027-2031 using UxC's High-Price Midpoint curve and using the Mid-Price Midpoint curve.

F2-Staff-214

Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 16

Preamble:

At Reference 1, OPG describes the Darlington New Nuclear Program (DNNP) facilities' nuclear fuel procurement supply chain and some procurements done in 2023-2025.

Question(s):

a) Please clarify where these 2023-2025 procured costs for DNNP facilities are being recorded.

F2-Staff-215

Ref 1: Exhibit F2 / Tab 6 / Schedule 1 / p. 1

Preamble:

At Reference 1, the Applicants state that they present "the purchases of OM&A expense services for OPG's nuclear operations (excluding Darlington Refurbishment, Pickering Refurbishment, Pickering Feasibility and Darlington New Nuclear Program) that meet the threshold of $20 million in total OM&A expense, consistent with the OEB filing requirements".

Question(s):

a) Please clarify where in the Applicants' evidence equivalent information on OM&A purchased services for Darlington Refurbishment, Pickering Refurbishment, Pickering Feasibility and Darlington New Nuclear Program can be found. If not provided, please provide the information.

F2-Staff-216

Ref 1: Exhibit F2 / Tab 6 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 4 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that the total OM&A purchase services expenditures for all contractors for the historical period (2020-2024) was $247.6 million in 2020, $300.5 million in 2021, $255.5 million in 2022, $287.4 million in 2023, and $275.6 million in 2024.

At Reference 2, Other Purchased Services actual amounts for 2020-2024 are included under Base OM&A.

At Reference 3, Other Purchased Services actual amounts for 2020-2024 are included under Outage OM&A.

OEB staff produced the following table showing other purchased services.

Table 1 – Other Purchased Services ($ millions)

	2020	**2021**	**2022**	**2023**	**2024**
Other Purchased Services - Base OM&A - Ref 2 table, Line 7	130.16	151.14	159.58	143.42	164.91
Other Purchased Services - Outage OM&A - Ref 3 table, Line 6	135.22	188.12	128.03	157.28	169.61
Total of Other Purchased Services, Ref 2 and Ref 3	**265.37**	**339.26**	**287.61**	**300.70**	**334.52**
Total OM&A purchase services expenditures, Ref 1	**247.6**	**300.5**	**255.5**	**287.4**	**275.6**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.
b) Please explain why the values in the two “Total” rows in Table 1 are different.

F3-Staff-217

Ref 1: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 17
Ref 2: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 27

Preamble:

At Reference 1, Elenchus recommended that, for allocating the costs of the Energy Markets department, “OPG consider using a MCR cost driver rather than OM&A/Capital for allocating costs within Renewable Generation”.

At Reference 2, Elenchus recommended that OPG enhance its internal written documentation of the cost allocation model and description of its allocation processes.

Question(s):

a) Is OPG planning to implement the Elenchus recommendation to use the Maximum Continuous Rating (MCR) cost driver discussed at Reference 1? If not, please explain OPG’s rationale and provide any analysis conducted to support its decision.
b) Is OPG planning to implement the Elenchus recommendation made at Reference 2? If not, please explain OPG’s rationale and provide any updated internal documentation.

F3-Staff-218

Ref 1: Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / p. 13
Ref 2: Exhibit F3 / Tab 1 / Schedule 1 / p. 9

Preamble:

The Hackett Group (Hackett), which completed OPG's last two corporate support costs benchmarking studies, was retained by OPG again to carry out the study for this Application.

At Reference 1, Hackett identified that OPG's HR process costs increased from $3,806 per employee in 2019 to $4,742 per employee in 2024, while the peer group median is at $3,543 per employee in 2024.

At Reference 2, in discussing HR process costs remaining in the 3rd quartile, OPG refers to "intensified recruitment and onboarding efforts and other support required through a period of increased hiring and workforce transition".

Question(s):

a) Please provide a more detailed explanation regarding why OPG's HR process costs increased by almost $1,000 per employee since 2019 and why OPG is $1,200 per employee higher than the peer group median.

F4-Staff-219

Ref 1: **Exhibit F4 / Tab 2 / Schedule 1 / p. 5**

Preamble:

OPG states that for 2020-2026, regulatory income taxes for the prescribed facilities are presented on a combined nuclear and hydroelectric basis, with total taxes before scientific research and experimental development (SR&ED) investment technology credits (ITCs) allocated based on each business' regulatory taxable income, while 2027-2031 are presented on a standalone basis, i.e. hydroelectric and nuclear are separate.

Question(s):

a) Please provide a bridge from the 2026 combined prescribed-facilities tax calculation to the separate 2027 standalone hydroelectric and nuclear tax calculations, showing separately:
   i. Changes arising from the move away from the combined calculation

ii. Changes in tax loss utilization
iii. Changes in SR&ED ITC attribution
iv. Any changes in reference amounts used for tax-related deferral and variance accounts.

F4-Staff-220

Ref 1: Exhibit F4 / Tab 2 / Schedule 1 / p. 1
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / p. 15
Ref 3: Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

OPG states that hydroelectric income taxes are embedded in the hydroelectric capital-related revenue requirement and C-factor because those taxes are predominantly (although not entirely) capital-related.

In Reference 2, OPG states that as of the effective date of the payment amounts order, the Income and Other Taxes Variance Account (OPG) reference amounts for hydro will be the corresponding 2027-2031 annual income tax provisions in Exhibit F4-02-01 Table 3b of the evidence. The Income and Other Taxes Variance Account shows that for hydroelectric, the account has a 2024 balance of ($17.3 million), with ($9.2 million) already approved for 2025-2026 amortization, and ($8.1 million) proposed for disposition in this application over 36 months.

Question(s):

a) Please provide, for each year of 2027-2031:
   i. The hydroelectric income tax amount embedded in the capital-related revenue requirement/C- factor
   ii. The portion OPG considers capital-related versus non-capital-related
   iii. An explanation of how OPG avoids duplication between recovery through the C-factor and additions to the Income and Other Taxes Variance Account (OPG) and any related hydro capital variance accounts.

b) For the Income and Other Taxes Variance Account – Hydroelectric,
   i. Please provide a reconciliation from the 2024 audited balance of ($17.3 million) to the ($8.1 million) proposed for disposition in this application, identifying each component by vintage, driver and amount.

ii. Reconcile which amounts were previously approved for amortization in EB-2023-0336 and explain the derivation of the ($9.2 million) shown in Reference 2.
iii. Reconcile the annual ($2.7 million) amortization amounts in 2027-2029 to the tax model line "Regulatory Liability Amortization – Income and Other Taxes Variance Account" in Reference 3.
iv. Confirm whether the account balance already includes the associated income tax impacts, i.e. gross-up, for each component.

F4-Staff-221

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 5

Preamble:

At Reference 1, OPG states that OPG was able to reach agreements with both the Power Workers' Union (PWU) and the Society of United Professionals (the Society) on more efficient downsizing provisions for a partial or total Pickering closure during the first rounds of bargaining after EB-2020-0290.

Reference 1 also states that the new provisions cover a potential downsizing related to the completion of the Darlington Refurbishment Program.

Question(s):

a) Please clarify whether there are any new workforce planning provisions in the agreements with the PWU or the Society related to the Pickering Refurbishment Program since 2024.

F4-Staff-222

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 5-6
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, the Applicants state that OPG also succeeded in maintaining the ability to use the Power Workers' Union (PWU)-represented term-based employees (Term Employees) and the Society of United Professionals (the Society)-represented extended temporary employees (ETEs). The Applicants state that this was a critical strategy in mitigating the impacts of a Pickering shutdown.

Reference 2 provides FTE, Compensation and Benefit information for OPG nuclear, OPG hydroelectric, DNNP LP. The Applicants' workforce classifications include Management, Society, PWU, Term/ETE/PECO Temporary, and Electrical Power Systems Construction Association (EPSCA).

Question(s):

a) Please show the number of Society ETE and PWU Term employees within each of the workforce classifications at Reference 2.
b) If Society ETE and PWU Term employees do not account for all employees in the Term/ETE/PECO Temporary classification, please explain.
c) Please explain how EPSCA employees' compensation is determined, given that those employees do not belong to the unions or management.

F4-Staff-223

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that it achieved permanent collective agreement provisions with the Society that allow for contracting out of professional services "securing increased agility and the option to manage temporary or peaking resource needs more cost effectively."

Question(s):

a) Please compare the cost effectiveness of contracting out professional services to the use of temporary and term employees.

F4-Staff-224

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 8
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, OPG states that at the end of 2024, it employed 10,332 Regular, Term and Extended Temporary Employees.

Reference 2 provides FTE totals by business. The 2024 value is 9,073 (p. 1 line 18) for OPG's nuclear business and 1,415.6 (p. 3 line 12) for OPG's hydroelectric business. The sum of these values is 10,488.6.

Question(s):

a) Please reconcile the difference between the value at Reference 1 and the sum using Reference 2 calculated by OEB staff in the preamble.

F4-Staff-225

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 11
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / pp. 15-17

Preamble:

At Reference 1, OPG states that by year-end 2025, approximately 11% of active regular employees (~1,065) will be eligible to retire with an undiscounted pension, with an additional 15% becoming eligible to retire between 2026-2031.

Reference 2 describes OPG's redeployment strategy. The strategy begins with redeploying 1,300 employees from the Pickering station to other areas of OPG Nuclear.

Question(s):

a) Please describe and explain how OPG Nuclear's redeployment strategy will affect the FTE counts of departments within Pickering Refurbishment, the Darlington generating station, and the DNNP. Please include an explanation of FTE trends in each of the described departments in the 2027-2031 period.
b) Does OPG allow for a period of overlap for the purpose of knowledge transfer between retiring employees and their replacements? How are overlaps of this kind reflected in the 2026-2031 compensation costs and FTE counts?

F4-Staff-226

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 14

Preamble:

At Reference 1, the Applicants state that since 2023, OPG has hired approximately 500 project managers and engineers and expects to continue hiring to ensure the appropriate resourcing through the IR term.

Question(s):

a) Are project managers' compensation costs capitalized to projects, expensed to OM&A, or a mix of both? Please explain.

F4-Staff-227

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 18

Preamble:

At Reference 1, OPG states that the increases in compensation costs over time primarily reflect the higher collective agreement wage increases over the last several years as well as wage escalation assumptions over the IR term.

Question(s):

a) Please provide the annual wage escalation assumptions for 2025-2031 for the Power Workers' Union (PWU), the Society of United Professionals (the Society), and management.

F4-Staff-228

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 20

Preamble:

At Reference 1, OPG states that as of 2022, Nuclear base OM&A FTEs were beginning to attrite to levels lower than those planned in EB-2020-0290, which if left unaddressed, would lead to inadequate staffing levels to meet operational needs. With the implementation of a responsive workforce plan, by 2023, FTE levels aligned more closely to the original planned resourcing requirements established in EB-2020-0290.

Question(s):

a) Please provide the planned vs. actual Nuclear Base OM&A FTE numbers and compensation costs in 2022 and 2023.

F4-Staff-229

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 21
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Figure 4b

Preamble:

At Reference 1, OPG states that the FTEs for the regulated hydroelectric facilities were largely stable over the 2020-2023 period, before increasing by 9% in 2024 and 15% in 2025, mainly to support major capital projects, including the turbine-generator refurbishment program.

Reference 2 shows that there are no Term employees or Extended Temporary Employees (ETE) in the regulated hydroelectric business.

Question(s):

a) Please confirm that none of the increase in regulated hydroelectric FTE count in 2024 and 2025 is due to the hiring of Term employees or ETEs. If not confirmed, please reconcile with Reference 2.
b) Did OPG consider using Term employees or ETEs to support its hydroelectric major capital projects? Please explain.
c) Does OPG expect its FTE complement to decline following the completion of its major capital projects? Please explain.

F4-Staff-230

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 27-28

Preamble:

The text in the four figures at Reference 1 is not readable.

Question(s):

a) Please provide searchable, high-resolution versions of the figures at Reference 1

F4-Staff-231

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 30-31
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 3

Preamble:

At Reference 1, OPG states that the Stakeholder Return Program is a short-term (i.e., single year) pay for performance incentive plan for eligible management employees, intended to deliver a portion of total compensation on a pay for performance basis. Since 2021, OPG has used a financial results model for deriving the amounts based on a percentage applied to forecast corporate earnings before tax.

Reference 2 is a Total Compensation Benchmarking Study conducted by Willis Towers Watson.

Question(s):

a) Please describe any changes to the Stakeholder Performance Program since EB-2020-0290.
b) Please confirm that the Stakeholder Performance Program costs are equivalent to the “Target Incentive” included under Total Direct Compensation in Reference 2.

F4-Staff-232

Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 33

Preamble:

At Reference 1, OPG states that its registered pension plan has Available Actuarial Surplus. In March 2025, OPG’s Board of Directors approved a reduction in OPG’s contributions to match the level of employee contributions over the 2025-2027 period, effective March 2025.

Reference 1 further states that the Available Actuarial Surplus is forecasted to continue throughout the IR term and that OPG’s 2025-2031 Business Plan and the Application assume that OPG’s employer contributions will continue to match employee contributions over this period.

Question(s):

a) By how much did OPG reduce its employer contribution in 2025 and 2026, relative to what would be required if the pension plan had not been in a funding surplus?
b) Please provide the estimated compensation cost savings in 2027-2031 arising from the assumption that employer contributions will continue to be lower than what would be required if the pension plan was not in a funding surplus?

F4-Staff-233

Reference 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1-2, 8

Preamble:

OPG states that the forecast 2027-2031 pension and other post-employment benefit costs (OPEB) for OPG's regulated facilities and the Darlington New Nuclear Program (DNNP) facilities included in the proposed revenue requirement are determined in accordance with US Generally Accepted Accounting Principles (GAAP). As in prior applications, OPG's accrual costs for pension and OPEB include several components.

Question(s):

a) Please confirm whether the pension and OPEB amounts included in the 2027-2031 revenue requirement are based on total annual accrual costs determined under OPG's US GAAP accounting treatment.
b) Please provide a breakdown for each forecast year showing the components of annual pension and OPEB cost reflected in the forecast revenue requirement, by major plan.
c) Please identify any components of annual pension and OPEB cost determined for financial reporting purposes that are not included in the forecast revenue requirement and explain why they are excluded.
d) Please confirm if OPG's accrual costs for pension and OPEB includes a component related to the amortized actuarial gains or losses (which is allowed under US GAAP). If so, please provide the figures for historical periods and also 2027-2031 related to the amortized actuarial gains or losses.

F4-Staff-234

Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 9-10, 26

Preamble:

OPG states that its pension and other post-retirement benefits (OPEB) costs are determined annually by an independent actuary using management's best estimate assumptions, both economic and demographic, and that many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes.

OPG also states that the expected long-term rate of return on the registered pension plan (RPP) fund assets continues to be calculated by its independent actuary, Aon, based on the pension fund asset mix and capital market expectations of future risk and return for each class. OPG states that many of the assumptions used in the going concern funding valuations are also applied in accounting valuations for determining the pension obligation and accrual costs.

Question(s):

a) Please identify the material assumptions and methodologies used to determine the annual pension and OPEB accrual costs included in revenue requirement, including any material plan asset-related assumptions.
    i. Please identify which of those assumptions and methodologies differ from those used in the actuarial valuations for funding purposes, as discussed in Reference 1.
    ii. For each material difference identified, please briefly explain the nature of the difference, and whether the difference affects the forecast revenue requirement, cash funding requirements, or both.
    iii. Please quantify, to the extent possible, the impact on forecast revenue requirement of each material difference identified in part a.
    iv. Please quantify the impact on forecast revenue requirement of changes in the most material plan asset-related assumption(s), using reasonable sensitivity ranges.

F4-Staff-235

Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 11-13, 18

Preamble:

OPG states that forecasting pension and other post-retirement benefits (OPEB) accrual costs requires projections of the actual pension fund performance as well as projections of assumptions that will be used to determine the actual obligations. OPG further states that the forecast 2026-2031 costs use assumptions determined as of the end of

December 2024, as updated, effective December 31, 2026, to reflect the 2024 Mortality Improvement Scale (MI-2024). The forecast 2025-2031 costs also reflect previously negotiated pension reform measures effective in 2025. OPG also states that pension costs increased from 2023 to 2024 due in part to updated salary increase assumptions and that 2026 to 2027 forecast costs increase due to the expected adoption of MI-2024.

Question(s):

a) Please identify all material changes in pension and OPEB assumptions or other forecast inputs reflected in the 2025 to 2031 forecast relative to the assumptions and inputs used in OPG's last payment amounts proceeding.
    i. For each material change identified, please explain the reason for the change.
    ii. For each material change, please quantify the impact on the forecast revenue requirement for each affected year.
b) Please provide a sensitivity analysis, in table form, showing the impact on the 2027-2031 pension and OPEB-related revenue requirement of an increase and decrease in the discount rate assumption of 25 basis points, and 50 basis points.

F4-Staff-236

Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1, 3, 5-8
Ref 2: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

Reference 1 presents both forecast accrual costs and forecast cash amounts, as well as the differential between the accrual costs and cash amounts. The exhibit also supports the request for disposition of balances in the various pension and other post-retirement benefits (OPEB) deferral and variance accounts (DVAs).

OPG notes that the operation of these DVAs is discussed in Reference 2, including the continued application of the account that records interest on the difference between pension and OPEB accrual costs and cash amounts.

Question(s):

a) For each historical year for which amounts have been recorded in the applicable pension and OPEB DVAs and are relevant to the balances requested for disposition in this proceeding, please provide a reconciliation of:
   i. The pension and OPEB amounts included in revenue requirement
   ii. the actual accrual costs
   iii. the actual cash funding or cash payment amounts
   iv. the actual amounts recorded in each applicable pension and OPEB variance and deferral account.
b) For each forecast year of 2026-2031, please provide a bridge between:
   i. The pension and OPEB amounts included in the revenue requirement
   ii. The forecast cash funding or cash payment amounts
   iii. The forecast amounts expected to be recorded in the applicable pension and OPEB DVAs.
c) Please explain the key reasons for the differences among the amounts in question a and b, including the extent to which the differences related to accounting treatment, funding valuation methodology, or timing.
d) Please confirm whether the same cost components reflected in forecast revenue requirement are also the basis for determining the actual or forecast amounts recorded in the applicable accounts. If not, please explain the differences.

F4-Staff-237

Ref 1: Exhibit F4 / Tab 4 / Schedule 1 / Table 1
Ref 2: Exhibit F4 / Tab 4 / Schedule 1 / pp. 3-7

Preamble:

At Reference 1, the table shows that nuclear insurance costs are flat from 2020 ($19.5 million) to 2026 ($18.1 million). Then, over the IR term, those costs are forecast by OPG to more than double to $40.7 million by 2031.

At Reference 2, OPG identified two reasons for the forecast increase:

1. An anticipated increase in the current nuclear insurance liability limit under the Nuclear Liability and Compensation Act (NLCA). OPG states, effective 2027, subject to final confirmation by NRCan, the nuclear liability limit is expected to increase from $1 billion to $1.2 billion, for each of Pickering and Darlington, following a five-year NRCan review of the limit.

2. OPG plans to purchase nuclear Business Interruption (BI) insurance for Darlington beginning in 2027 to mitigate the potential loss of earnings and potential impact on OPG's credit ratings in the event of physical damage to the station from a nuclear peril. OPG notes it has not historically procured this coverage.

OPG further notes the BI coverage is not necessary for Pickering until the first unit returns to service and Darlington New Nuclear Program (DNNP) will be insured separately.

In relation to the potential change to the NLCA liability limit, OEB staff reviewed NRCan's Summary of Findings from its Five-Year Review document which notes the following: (1) "An inflation considered value would bring the nuclear third party liability limit to C$1.1 billion."; (2) "Any increase to the liability limit should be phased in gradually …"; and (3) "Internationally the liability limit is increasing with the entry into force of the Amended Paris Convention (2004) in January 2022. This amendment will require that operators in signatory States hold over ~C$1.04 billion." NRCan indicated the current $1 billion was implemented over a three-year phase in period (from $650 million).

Question(s):

a) Please provide a table that shows the forecast increase in costs for each year of 2027 to 2031 attributable to the NLCA and the BI coverage separately.
b) Given NRCan's findings (inflation adjustment to $1.1 billion, gradual phase in, etc.) on the potential change to the NLCA liability limit and the prior phase in to increase it to $1 billion, please explain OPG's anticipated immediate increase to $1.2 billion.
c) In relation to the new BI coverage, please explain why OPG did not consider it to be necessary in the past, but believes it is necessary going forward.
d) Please identify how many times the new BI coverage would have been triggered over the past decade.
e) OPG has indicated its intent to have the BI coverage for all of its nuclear facilities – Darlington, Pickering, DNNP – as they come into service. Table 1 is limited to Darlington and therefore does not reflect what the ultimate full impact would be on consumers. Please provide a table that reflects the cost associated with a hypothetical scenario whereby all the units are in service and have the BI coverage during this IR term (with Darlington, Pickering, and DNNP shown separately). Alternatively, provide a forecast of the cost for when OPG expects all those nuclear units will be in service.

EXHIBIT G – OTHER REVENUES

G1-Staff-238

Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 10
Ref 2: Exhibit G1 / Tab 1 / Schedule 1 / Table 1

Preamble:

At Reference 1, it notes that OPG is proposing to retain 20% of the net revenues from the sale of Clean Energy Credits (CECs). It states that, under O. Reg 39/23 (s. 4.2), "the Province specifies that the proceeds OPG is to remit is equivalent to 80% of its revenues net of costs from the sale of CECs to the Province's Future Clean Electricity Fund". OPG notes it is proposing to retain all the remaining net revenues from the sale of CECs "to provide an appropriate incentive for the organization to continue pursuing CEC sales."

At Reference 2, unlike the other sources of non-energy revenues, the table includes no row to address CECs (and the associated actual and forecast revenues).

In an OPG letter dated July 15, 2022 (responding to an OEB letter), OPG provided actual revenues and volumes of OPG's CECs from July 1, 2014 through December 31, 2021. In 2021, CEC revenues had increased to $5.5 million. OPG also provided forecast revenues and production quantities for 2022 – 2026 in that letter.

OPG's 2024 Annual Report (p.63) states: "In January 2025, OPG entered into an agreement with … Magna International Inc. … to supply CECs sourced from the Sir Adam Beck hydroelectric generating complex."

Question(s):

a) Please provide the actual annual revenues and production quantities for 2022-2024, and a forecast of annual revenues and production quantities for the IR term (separately for the regulated Hydroelectric and Nuclear facilities). Please reflect the new agreement with Magna in the forecast.
b) Does contributing to the Clean Electricity Fund provide an incentive for OPG to pursue CEC sales? Please explain.

c) In prior OPG applications, forecasts of all nuclear non-energy revenues have been treated as an offset in the calculation of OPG's nuclear revenue requirement. Please explain why CEC revenues should be treated differently.
d) OPG has proposed a revenue requirement for the IR term. How would OPG use these additional CEC revenues?

G1-Staff-239

Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Exhibit G1 / Tab 1 / Schedule 2 / p. 2

Preamble:

At Reference 1, the table shows that, in 2024, actual revenues related to Capacity Exports are about double the revenues in the prior years. Then revenues are forecast to decline back to prior year levels over the IR term.

At Reference 2, OPG explains that Installed Capacity (ICAP) Market revenue is $1.5 million higher than 2023 mostly due to OPG clearing the New York Independent System Operator capacity auction for more commitment months in 2024.

Question(s):

a) Please explain why the higher ICAP revenues that were realized in 2024 is considered to be an outlier by OPG. Please discuss whether 2024 ICAP revenues could indicate a potential trend.

G1-Staff-240

Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 5

Preamble:

At Reference 1, in explaining Operating Reserve (OR) revenues, OPG says an "expected addition of approximately 3,000 MW of battery energy storage facilities between 2025-2028 will put downward pressure on OR prices". That 3,000 MW expected increase in battery energy storage is also discussed in other parts of the

Application within the context of lower revenues and/or lower prices relative to "those experienced the Legacy Market".

Question(s):

a) Please identify the source of this forecast increase of 3,000 MW by 2028. If it is an OPG forecast, please explain the basis for the 3,000 MW of new battery energy storage facilities.

G1-Staff-241

Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 3

Preamble:

At Reference 1, OPG explains the provision of Regulation Service at Sir Adam Beck 2 Generation Station requires turbine modulation that can result in a portion of water flows not being utilized by OPG for electricity production (Unutilized Water). OPG further notes that the Niagara Hydrogen Centre (NHC), which is to be constructed and operated by Atura H2 LP (and is expected to enter service in 2026), will make use of the Unutilized Water. OPG also states the new agreement is consistent with the expectations set out in the Minister of Energy's letter to the IESO dated December 9, 2022.

OEB staff notes that the Application does not appear to indicate what happens with the revenues under OPG's new Regulation Service agreement with Atura H2 LP (a subsidiary of OPG) who uses the Unutilized Water from an OPG regulated facility.

Question(s):

a) Please clarify how OPG proposes to treat these revenues. In doing so, please explain how the following from the December 2022 Minister's letter has been reflected: "I understand from the IESO that OPG might agree to a reduction in compensation in the order of $1 million per year under a new contract."
b) Please clarify how Regulation Service revenues were treated in the past (i.e., prior to Atura H2 LP being involved).

G1-Staff-242

Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / Table 1

Preamble:

OEB staff created the chart below based on the Hydroelectric Incentive Mechanism (HIM) revenues provided by OPG in Table 1 of Reference 1 to better understand the trends.

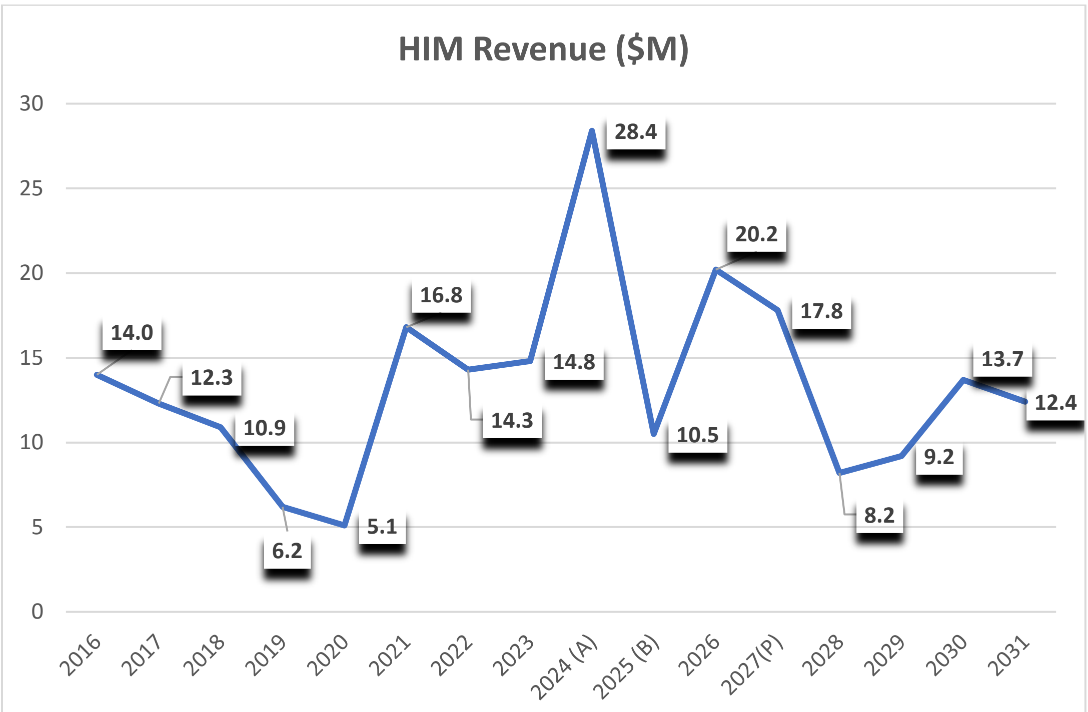

Chart 1 – HIM Revenue

Question(s):

a) Please explain the key driver(s) contributing to the HIM revenue volatility with almost a six-fold increase from 2020 to 2024 in actual revenues – $5.1 million (2020) to $28.4 million (2024) – followed by forecast revenues involving almost a three-fold decline to $10.5 million (2025) and then almost a two-fold increase to $20.2 million (2026).

b) Please explain why OPG is forecasting a significant decline in annual revenues of over $5 million per year during the IR term (with annual average forecast revenues during the five-year IR term at $12.3 million, while the annual average is $17.6 million over the five years before the IR term).

G2-Staff-243

Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 2
Ref 2: Exhibit F3 / Tab 2 / Schedule 1 / p. 1

Preamble:

At Reference 1, OPG notes that Cobalt-60 is a medical isotope and production at Pickering will cease over the IR term due to the refurbishment, with the final harvest expected in 2027. It also states that OPG is moving forward to produce Cobalt-60 at Darlington starting in 2028 and OPG is proposing to establish an asset service fee (ASF) associated with that production.

OPG notes in this Application that, in EB-2020-0290, OPG had discussed taking a different approach that involved bringing forward a “proposal involving revenues, operating costs and capital amounts for the production of Cobalt-60 at Darlington in the next nuclear payment amounts application”.

At Reference 2, it states “The generating businesses, including DNNP, are charged an ASF for the use of the assets, which are included in the respective OM&A expenses in the Application.”

Question(s):

a) Please explain why OPG is proposing a different approach involving the ASF, rather than the approach discussed in the EB-2020-0290 proceeding.
b) Please provide an explanation that compares how OPG recovers its costs under the two different approaches including the amount that would be recovered from consumers under each approach.

G2-Staff-244

Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 4
Ref 2: Exhibit G2 / Tab 1 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG explains that heavy water processing is comprised of tritium removal (detritiation) at the Tritium Removal Facility (TRF) and the TRF is reaching end of life. OPG is therefore undertaking the TRF Major Component Replacement Program, consisting of multiple projects over six outages between 2026-2038 (D2-T1-S3, section 3.1.3). OPG further states that heavy water processing is planned over the IR term based on TRF availability assumptions.

At Reference 2, the table indicates Heavy Water Sales & Processing (which is redacted) has historically accounted for the majority of Total Non-Energy Revenues and the forecast trend in the latter for the IR term appears to be consistent with the actual Total Non-Energy Revenues trend, except for 2027 where there is a significant decline from $42.9 million to $16.4 million and then increases back up to $43.5 million in 2028.

Question(s):

a) Please provide the TRF availability assumptions. For example, is 2027 the only year during the IR term that heavy water processing is expected to be impacted by the TRF Major Component Replacement Program?

G2-Staff-245

Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 5
Ref 2: Exhibit G2 / Tab 1 / Schedule 2 / p. 2

Preamble:

At Reference 1, in relation to reactive support and voltage control (RSVC) service, OPG states forecast revenues over the IR term are expected to be zero under an agreement with the IESO. The reason provided for zero revenues is OPG only earns revenue “tied to production losses resulting from provision of the RSVC service outside the standard capability range of the respective resources”. OPG further notes it is proposing to discontinue entries into the related Ancillary Revenues Variance Account sub-account since no revenues are expected and the relatively modest variance amounts historically settled through the sub-account.

At Reference 2, OPG explains that the 2026 budgeted RSVC revenues are higher than the OEB approved revenues due to higher utilization of this ancillary service than OPG had expected.

Question(s):

a) Please clarify what revenue “tied to production losses … outside the standard capability range” means within the context of providing RSVC service.
b) Did budgeted RSVC revenues exceed OPG expectations in 2026 under the current agreement with the IESO? If so, please explain why OPG expects zero revenues over the IR term.
c) Given the current agreement with the IESO ends in July 2028 and the IR term extends out to 2031, does OPG’s expectation of continued zero revenues mean OPG expects to cease providing this service and will not enter into a new agreement with the IESO starting in August 2028?
d) If OPG does expect to enter into a new agreement with the IESO starting in August 2028, please explain why OPG plans do so if it expects no revenues (i.e., no utilization of RSVC service).

EXHIBIT H – DEFERRAL AND VARIANCE ACCOUNTS

H1-Staff-246

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 4-5
Ref 2: Exhibit I1 / Tab 1 / Schedule 1

Preamble:

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

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

Question(s):

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

H1-Staff-247

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 4-6
Ref 2: Exhibit I1 / Tab 1/ Schedule 1 / Table 6

Preamble:

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

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

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

Question(s):

a) Please confirm whether, following the introduction of CCR effective January 1, 2026, no interest is capitalized on construction work-in-progress (CWIP) for DNNP assets.

b) Please explain how differences in financing parameters associated with the DNNP capital structure during construction are allocated between the CCR mechanism and the DNNP Generator Capital Structure Variance Account.
c) Please confirm that financing cost variances recorded in the DNNP variance accounts do not overlap with CCR recovery.
d) Please provide a sensitivity analysis showing the impact of a +/-100 basis point change in debt costs on:
    i. DNNP capital structure variance account balances
    ii. Nuclear payment amounts

H1-Staff-248

Ref 1: **Exhibit H1 / Tab 1 / Schedule 1**

Preamble:

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

Question(s):

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

H1-Staff-249

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / Table 1
Ref 2: Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

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

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

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

Question(s):

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

H1-Staff-250

Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / Table 2
Ref 2: Exhibit F4 / Tab 2 / Schedule 1 / Table 3d

Preamble:

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

Question(s):

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

H1-Staff-251

Ref 1: Exhibit H1 / Tab 1 / Schedule 1
Ref 2: Exhibit H1 / Tab 2 / Schedule 1 / Table 2
Ref 3: Exhibit F4 / Tab 2 / Schedule 1

Preamble:

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

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

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

Question(s):

a) Please reconcile the 2024 audited balance of ($25.7 million) to the ($25.2 million) proposed for disposition in Reference 2, including the derivation of the ($0.4 million) already approved amortization amount.
b) Please provide a breakdown of the 2024 audited balance including, for example:
    i. Current year variances
    ii. Prior year true-up entries
    iii. Audit resolution adjustments
    iv. Carrying charges
    v. Any embedded taxes on the difference
c) Please confirm which components include the associated tax on the ITC difference and show the gross-up calculation.
d) Please explain how the annual ($8.4 million) amortization amounts for the SR&ED ITC Variance Account (Nuclear) are reflected in the overall revenue requirement and payment amounts, including whether those amounts are reflected only through riders, or also reflected in any line of the nuclear income tax model in Reference 3.
e) Please provide the implementation details of the proposed extension of the SR&ED ITC Variance Account (OPG) to the hydroelectric facilities, including:
    i. The effective date;
    ii. The transition rule between the historical hydroelectric treatment in the Income and Other Taxes Variance Account and the proposed treatment in the SR&ED ITC Variance Account;
    iii. A working example showing how a hydroelectric SR&ED ITC variance arising after the effective date would be recorded;
    iv. Confirmation that no overlap will occur between the two accounts during transition.

H1-Staff-252

Ref 1: Exhibit H1 / Tab 2 / Schedule 1

Preamble:

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

Question(s):

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

H1-Staff-253

Ref 1: Exhibit H1 / Tab 1 / Schedule 1
Ref 2: Exhibit A1 / Tab 2 / Schedule 3 / pp. 3-6

Preamble:

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

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

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

Question(s):

a) Please provide an illustrative, numerical example using annual entries over the 2028-2031 period that shows:
    i. The annual capital-related entries recorded in the hydroelectric CRVA for an eligible portfolio project;
    ii. The corresponding calculation of the GHCVA based on actual versus forecast capital-related revenue requirement
    iii. The resulting cumulative adjustment between the CRVA and GHCVA at the end of the 2028-2031 period
    iv. The final amount, if any, proposed for disposition from each account.
b) Please provide an illustrative, numerical example for the 2023 and 2024 years had the GHCVA existed. If necessary, please also explain if CRVA entries would have been different had the GHCVA existed.
c) Please ensure that the example demonstrates how OPG would avoid duplication and how the proposed cumulative limit would be applied in practice.

H1-Staff-254

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 64-65
Ref 2: Exhibit I1 / Tab 3 / Schedule 2 / pp. 6-9

Preamble:

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

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

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

Question(s):

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

H1-Staff-255

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

Preamble:

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

- the hydroelectric components of the Capacity Refurbishment Variance Account - $120.7 million

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

Question(s):

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

H1-Staff-256

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

Preamble

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

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

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

Question(s):

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

H1-Staff-257

Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Preamble

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

Question(s):

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

c) Please provide a draft accounting order including illustrative entries.

H1-Staff-258

Ref 1: Exhibit A1 / Tab 2 / Schedule 2 / p. 7
Ref 2: Exhibit I1 / Tab 1 / Schedule 3 / pp.8-9

Preamble

Reference 1 outlines that OPG is seeking approval of an annual process to recover balances recorded in the Darlington New Nuclear Project (DNNP) Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project (PRP) Variance Account, beginning with recovery of 2026 balances during 2027. OPG also notes that pursuant to O. Reg 53/05, recovery is to occur in the year following the year in which amounts are recorded, to the extent the OEB is satisfied the amounts are accurately recorded.

Reference 2 outlines the Applicants' proposal for this annual recovery.

Question(s):

a) Please explain whether the Applicants plan to dispose of the PRP and DNNP concurrent cost recovery (CCR) variance account amounts on an audited or forecast basis.
b) Please describe the proposed review and true-up mechanism for any forecast to actual differences, corrections, or audit adjustments identified after the year-end and how they would be treated.
c) Please describe the evidence OPG expects to provide each year to enable the OEB to be satisfied that the balances are accurately recorded, including at minimum, confirmation of:
    i. A continuity schedule with the opening balance, transactions, interest, closing balance;
    ii. A reconciliation to audited source records;
    iii. Supporting details for capital expenditures and in-service amounts, as applicable;
    iv. A demonstration that no duplication has occurred with amounts otherwise reflected in payment amounts or other DVAs.

d) Please describe the proposed interest calculation methodology, including the applicable interest rate, and period over which interest accrued.
e) Please explain whether the Applicants propose to set the associated payment amount ride on the basis of an already OEB-approved production forecast or a new production forecast provided through that application. Please include the rationale for this proposal.
f) Please explain whether and how the Applicants considered combining this application to recover CCR amounts with other annual applications from either OPG, DNNP LP, or the Applicants.

H1-Staff-259

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 60-63, 71-72
Ref 2: Exhibit A1 / Tab 6 / Schedule 1
Ref 3: Exhibit A1 / Tab 6 / Schedule 1 / Attachment 3

Preamble:

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

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

Question(s):

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

h) Please explain how OPG proposes to address situations where the Changes of Laws Deferral Account would record material impacts to revenues that also relate to other approved or proposed accounts.

H1-Staff-260

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / p. 1
Ref 2: Clarification on Filing Requirements for Ontario Power Generation Inc. and Policy Report Retirements
Ref 3: Exhibit H1 / Tab 2 / Schedule 1 / p. 1
Ref 4: OPG Reporting to the OEB

Preamble:

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

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

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

Question(s):

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

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

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

H1-Staff-261

Ref 1: Exhibit H1 / Tab 1 / Schedule 1 / pp. 51, 52, and 70
Ref 2: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement, Exhibit 0 / Tab 1 / Schedule 1 / p. 29, July 16, 2021

Preamble:

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

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

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

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

Question(s):

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

H1-Staff-262

Ref 1: EB-2024-0136, OEB Letter, Updated Filing Requirements for Ontario Power Generation Inc., September 17, 2024
Ref 2: Exhibit D4 / Tab 1 / Schedule 1 / p. 1

Preamble:

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

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

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

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

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

Question(s):

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

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Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / pp. 1 & 2

Preamble:

OPG stated that as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario) (O. Reg. 395/11), its consolidated financial statements are prepared in accordance with US Generally Accepted Accounting Principles (GAAP).

OPG stated that since January 1, 2012, OPG has sought and received exemptive relief from the Ontario Securities Commission (OSC) and other provincial securities regulators from the requirements of *National Instrument 52-107* (NI 52-107) that allows OPG to file its financial statements using US GAAP instead of International Financial Reporting Standard (IFRS) for continuous disclosure purposes.

OPG stated that the term of the most recent exemption expires on January 1, 2027, subject to certain conditions. In October 2025, OPG filed an application with the OSC requesting the extension of the exemption to the earlier of the effective date of a mandatory IFRS standard for rate-regulated entities (expected to be January 1, 2029) and January 1, 2032.

The application says that the IFRS standard for rate-regulated entities is expected to be finalized in the second quarter of 2026. https://www.ifrs.org/projects/work-plan/rate-regulated-activities/

Question(s):

a) Please provide an update on OPG's October 2025 application with the OSC, including whether OPG has received an exemption to January 1, 2032.
b) Would the OSC exemption also apply to DNNP LP?
c) Please elaborate on the expected implications of the mandatory IFRS standard for rate-regulated entities for both OPG and DNNP LP. Is it anticipated that OPG and/or DNNP LP may move from US GAAP to IFRS before the end of the proposed five-year payment amount term?

H1-Staff-264

Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / pp. 1 & 2
Ref 2: EB-2012-0002, Settlement Agreement, March 14, 2013, pp. 3 & 25 (revised March 22, 2013)
Ref 3: EB-2012-0002, Payment Amounts Order, April 18, 2013, p. 2
Ref 4: EB-2021-0110, Hydro One Networks Inc., Decision and Order on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants, November 29, 2022; Settlement Proposal, October 24, 2022, pp. 54 & 107

Preamble:

OPG stated that as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario) (O. Reg. 395/11), its consolidated financial statements are prepared in accordance with US Generally Accepted Accounting Principles (GAAP).

In 2012, OPG filed an application regarding the adoption of US GAAP for regulatory purposes. In the settlement agreement in that proceeding, the Parties agreed that OPG's adoption of US GAAP for regulatory accounting, reporting and rate-making purposes effective January 1, 2012 was appropriate. The settlement agreement was approved by the OEB.

Hydro One Networks Inc. (Hydro One) filed an application for the period January 1, 2023 to December 31, 2027. A settlement proposal for Hydro One was approved by the OEB on November 29, 2022, including the following terms:

> …the Parties agree that subject to the accounting system limitations identified by Hydro One during the proceeding and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will in its next cost-based rate application provide, on a best efforts basis, estimated impacts of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. Hydro One will also, on a best efforts and without prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes…
>
> …to the extent reasonably possible, the impacts will be broken down based on the areas of potential revenue requirement impacts identified in the PwC US GAAP to IFRS Conversion Impact Review Report (Exhibit A/Tab 6/Schedule 1/Attachment 1/p. 9)…

Question(s):

a) Please explain whether OPG would see any barriers to performing the tasks agreed to by Hydro One in Hydro One's settlement agreement for 2023-2027 rates and present the results of such tasks in OPG's next payment amounts application (for payment amounts beginning in 2032).

EXHIBIT I – DETERMINATION OF PAYMENT AMOUNTS

I1-Staff-265

Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Attachment 1, Sheet 11
Ref 2: Exhibit I1 / Tab 3 / Schedule 2 / Attachment 1

Preamble:

At Reference 1, OPG presents a 2027 Bill Impact. In the Production and Demand section, OPG presents its forecast production as 51.2 TWh and the IESO forecast provincial demand as 163.9 TWh. The Bill Impact assessment shows OPG's proportion of Consumer usage as 31.2%.

At page 16 of Reference 2, Innovative Research Group states that OPG is responsible for about half of Ontario's electricity.

Question(s):

a) Noting the Customer Engagement Report identifies field dates in November 2025, please explain the discrepancy between stating to participants that OPG is responsible for about half of Ontario's electricity while the Bill Impact assessment in Reference 1 shows OPG's proportion as 31.2%.

b) Please explain and provide the calculation of the following statements made at page 16 of Reference 2:
   i. The hydroelectric fleet account for 30% of OPG's 2027-2031 plan
   ii. The nuclear fleet account for 65% of OPG's 2027-2031 plan
   iii. Roughly 5% of OPG's proposed 2027-2031 budget will fund development of the first grid-scale small modular reactor project in North America

c) For the figures referenced in part b), please confirm, and if not confirmed explain, the following:
   i. That the "2027-2031 plan" and "2027-2031 budget" are the same
   ii. That the plan/budget referenced to the participants of the survey are the same as the revenue requirements brought forward in this proceeding
   iii. That the plan/budget referenced to the participants of the survey include both OPG's and DNNP LP's requested revenue requirements

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Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Chart 1
Ref 2: <u>2024 EBT Estimate Prescribed RRR Final. Non-Confidential.pdf</u>

Preamble:

At Reference 1, OPG presents actual and forecast return on equity for 2022-2026. Reference 2 is the 2024 Annual Regulatory Return reported to the OEB.

Question(s):

a) Please reproduce Reference 2 to show 2025 and 2026 forecast return on equity, including all supplementary notes and sub-tables, as per Reference 1.

I1-Staff-267

Ref 1: Exhibit I1 / Tab 3 / Schedule 2

Preamble:

With Reference 1, OPG presents its payment amount shaping proposal.

Question(s):

a) Please identify and explain all other payment amount mitigation proposals the Applicants considered.
b) Please outline and describe the decision criteria the Applicants used to determine the proposed payment amount shaping and deferral account should be the proposal brought forward in this application.

I1-Staff-268

Ref 1: Exhibit I1 / Tab 4 / Schedule 1
Ref 2: EB-2020-0290, OPG Letter RE: Interim Payment Amounts and Timing of Final Payment Amounts Order, December 23, 2021

Preamble:

With Reference 1, OPG provides a description of the IESO settlement process used for OPG's regulated generation facilities and the Darlington New Nuclear Program (DNNP) facilities. The evidence states that a final rate order establishing new payment amounts would have to be issued by the 20^{th} day of the second month prior to the implementation month. Reference 1 provides the example that a rate order would have to be issued by January 20 to implement payment amounts for March 1:

> OPG and DNNP LP understand that in order for revised payment amounts and riders to be implemented on the first of a given month, a final rate order establishing the new payment amounts and riders would have to be issued by the 20th of the second month prior to the implementation month. This timing is necessary for the IESO to update their systems and perform the settlement without retroactive adjustment. For example, for implementation on March 1st, the rate order would have to be issued in January, before the 20th.

Reference 2 is a letter from OPG in the EB-2020-0290 proceeding. In that letter, OPG states that it conferred with the IESO as to the latest date that a final payment amounts order could be issued to avoid additional riders to recover foregone revenue. That letter provides the example that a payment amounts order would have to be issued by February 20 to ensure that the IESO could implement payment amounts for January 1:

> OPG has conferred with the IESO as requested. The IESO indicated that issuance of the final payment amounts order by February 20, 2022 will ensure that the IESO will be able to implement an effective date of January 1, 2022 without the need for a separate shortfall mechanism.

Question(s):

a) Please confirm the latest date for the OEB to issue a payment amounts order so that the IESO could implement payment amounts for January 1, 2027 without additional riders to recover foregone revenue.