UNDERTAKING JT1.1

Undertaking

Reference: A2-Staff-016(c), Attachment 1.

Preamble 1: The Ministry of Energy sent a letter to OPG on April 22, 2026, outlining its expectations for OPG's next business plan. At pages 3 and 6 of the above reference in Attachment 1, the letter contemplates a potential equity investment from First Nations partners in DNNP LP.

Questions:

b) Please explain how OPG is advancing the objectives set out in its Reconciliation Action Plan and Indigenous Relations Policy through this rate application, including the potential equity investment by First Nations partners. In this response, please include an explanation of how the objective of First Nations economic reconciliation was considered within the rate application.

c) Please explain how OPG intends to communicate future strategic opportunities to First Nations partners.

Response

a) OPG's Indigenous Relations Policy and Reconciliation Action Plan formalize the company's commitment to working with Indigenous Nations and communities to foster positive and mutually beneficial relationships, with such commitments integrated in its Business Plan (Ex. A2-2-1, Section 3.4).

Through this Application, OPG is advancing these objectives, including as follows:

- Regulated Hydroelectric Facilities (Ex. A1-4-2, Section 3.4):
    i. To date, OPG (and formerly Ontario Hydro) has completed past grievance settlements with 21 First Nation communities across Ontario to address some of the effects on Indigenous communities. The program is voluntary and non-adversarial.
    ii. OPG and the Fort William First Nation, have reached an agreement in principle whereby OPG would provide a redevelopment revenue payment to be made on an annual basis, beginning when the Kakabeka Falls GS is returned to service in 2028 following redevelopment (refer to Ex. D1-1-2, pp. 29-30).
- Nuclear Facilities (Ex. A1-4-3, Section 6.0):
    i. Through OPG's Indigenous Opportunities Network ("ION"), a collaboration between OPG, the Electrical Power Systems

Construction Association, Kagita Mikam Aboriginal Employment and Training, unions, and vendors engaged on the Darlington Refurbishment project, Indigenous participants are placed in energy sector building trades, such as carpenters, boilermakers, and millwrights.

ii. As of December 31, 2024, the ION program exceeded its annual target by 10 percent, with 55 ION participants placed into employment roles. Since the program was launched in 2018, a total of 180 ION participants have been placed into employments roles.

- Pickering Refurbishment (Ex. D2-3-8, Attachment 1):
  i. A comprehensive Indigenous Engagement Plan for the Pickering site was finalized in Q2 2024 based on feedback from Indigenous Nations and communities.
  ii. The Pickering Refurbishment team continues to prioritize Indigenous Relations with engagement in support of the licencing process, engagement with vendor partners, documented consideration in program planning, perimetry requirements associated with the Deep Water Intake program and any ground disturbing activities along with finalizing long-term Capacity Funding Agreements with the Michi Saagiig Communities.
- Procurement (Ex. F3-3-1, Section 7.0)
  i. OPG's procurement process reflects a commitment to advancing procurement from Indigenous and diverse businesses. In particular, OPG has implemented practices and initiatives that promote the expansion and capacity of diverse suppliers, and Indigenous economic empowerment and growth in alignment with OPG's Reconciliation Action Plan.
  ii. OPG's supplier outreach strategies focus on expanding awareness of procurement opportunities and improving access for a broad and diverse supplier base. This includes sharing upcoming contracting opportunities through supplier information sessions and industry days, maintaining clear procurement information, and engaging with the market to explain requirements, timelines, and how to do business with OPG. OPG works with Indigenous and other diverse suppliers by promoting networking and capability-building opportunities, with the aim of increasing participation, competition, and value in its supply chain.

Furthermore, as discussed at Ex. L-A2-Staff-016, with respect to the DNNP facilities, OPG has been working with WTFN Investment Holding Limited Partnership to explore economic opportunities in the DNNP. On June 23, 2026, the seven Williams Treaties First Nations ("WTFN") Chiefs along with the Provincial Ministers of Energy and Finance and the Federal Minister of Finance and National

Revenue, announced a $700 million WTFN investment in respect of the project through WTFN Investment Holdings LP.

b) OPG will continue to communicate with First Nations partners through ongoing relationship frameworks that support regular dialogue, transparency, and trust-building. OPG recognizes that long-term, respectful relationships are the foundation for successful commercial relationships, and that any such future opportunities that may arise are best advanced through established channels of engagement with First Nations partners.

UNDERTAKING JT1.2a

Undertaking

Reference: A1-MC-001
Reference: F2-MC-008

Question(s):

Please describe how OPG's existing procurement processes address the Directive for the 2027-2031 period, including:

a) the procurement planning steps OPG understands to be required by the Directive;
b) any existing evaluation criteria or procurement considerations that OPG relies on to address Ontario-based, regional, local, or proximity-based supply chain outcomes;
c) any internal guidance, templates, procedures, or communications used by OPG to implement or operationalize the Directive;
d) any internal group, role, or business unit responsible for monitoring OPG's compliance with the Directive; and
e) the basis for OPG's statement that the requirements issued to date do not result in incremental or material costs beyond those already reflected in the 2025-2031 Business Plan.

Response

a) The Buy Ontario Procurement Directive ("Directive") comprises three operative sections: 1) the Building Ontario Businesses Initiative; 2) the Procurement Restriction Policy (U.S. Businesses); and 3) Strategic Categories (Fleet Management and Capital Infrastructure).

   1) Regarding the Building Ontario Businesses Initiative, OPG is exempt from the requirements for energy-related procurements. For other procurements, OPG understands that pursuant to the Directive, where required, OPG is to prioritize Ontario suppliers, Canadian suppliers, or suppliers from Ontario's trading partners depending on the value of the procurement.
   2) Regarding the Procurement Restriction Policy, OPG understands that it is to prohibit U.S. businesses from participating in procurements unless one of the exemptions contained in the Directive applies.
   3) Regarding the Strategic Categories of the Directive, OPG is exempt from the Capital Infrastructure requirements. Regarding Fleet Vehicles, OPG is required to purchase or lease Made-in-Ontario Fleet or, where that is not feasible,

purchase or lease a new vehicle from an Ontario Vehicle Producer or, if that is not feasible, consider alternative acquisition strategies.

b) OPG includes evaluation elements in its procurement events, as applicable and appropriate, to meet the requirements of the Directive.

c) OPG has posted and distributed an internal communication to the Supply Chain fleet management announcing the new requirements under the Directive for fleet management. Additionally, the communication is posted on the internal OPG website.

OPG distributed an internal guide to Supply Chain staff as it relates to U.S. Procurement Restriction Policy. The guide provides information on how to comply with the requirements of the Directive.

The above updated requirements will be incorporated into OPG governance at the next scheduled governance update, as appropriate.

d) OPG's Supply Chain function is responsible for ensuring compliance with the Directive, with support from the Law department.

e) As noted in Ex. L-F2-MC-008, based on the *Buy Ontario Act* and the requirements issued to date, related administrative costs are embedded within OPG's existing procurement process and do not result in incremental or material costs beyond those already reflected in OPG's 2025-2031 Business Plan. The basis for that statement is that OPG's procurement practices are already compliant with existing public sector procurement directives applicable to OPG, and the *Buy Ontario Act* requirements can be implemented within these established processes without requiring incremental resources or system changes beyond what was included in the 2025-2031 Business Plan.

UNDERTAKING JT1.2b

Undertaking

Reference: A1-MC-001
Reference: F2-MC-008
Reference: F3-MC-009

Question(s):

Please identify the existing metrics, reports, scorecards, or other mechanisms OPG uses or intends to use to monitor procurement outcomes relevant to the Directive, including any information relating to:

a) spend or contract awards with Ontario-based suppliers;
b) local or regional supplier participation;
c) participation by Indigenous, community-owned, or rightsholder-affiliated businesses;
d) facility-level or project-level procurement outcomes for Pickering, Darlington, DNNP, and WWMF; and
e) any reporting to the Province, OPG management, or OPG's Board.

Please provide any available 2023-present results for these metrics, or explain whether and why such results are not tracked in OPG's existing systems.

Response

a) - e) OPG is in compliance with the Buy Ontario Procurement Directive ("Directive"), as currently issued. The Directive focuses on procurement decision-making requirements, specifically, prioritization of Ontario and Canadian suppliers where applicable. The Directive does not require prescriptive outcome-based reporting across additional dimensions.

Accordingly, OPG's existing monitoring and reporting mechanisms are aligned to these requirements.

UNDERTAKING JT1.2c

Undertaking

Reference: F3-MC-011

Question(s):

Please describe the data fields used by OPG to track this contract award and spend data, including whether OPG records:

a) supplier classification categories;
b) whether the supplier is Indigenous-owned, First Nation-owned, community-owned, or rightsholder affiliated;
c) whether the supplier is a prime contractor or subcontractor;
d) contract value, actual spend, and year of award/spend;
e) business unit, project, facility, or procurement category;
f) supplier location; and
g) any treaty-area, community, or rightsholder affiliation.

Response

a) OPG does not have a data field called supplier classification categories.

b) and g) OPG does not track the referenced information as described in the question. OPG anticipates implementing this within the IR term. Broader supplier classifications are not tracked at this time.

c) - f) OPG tracks this information as described above.

UNDERTAKING JT1.2d

Undertaking

Reference: L-F3-MC-011
Reference: L-F3-MC-012

Question(s):

Please provide OPG's definitions, and how it verifies qualification including whether OPG verifies affiliation with Williams Treaties First Nations or Treaty 45 ½ First Nations, of the following terms (or such other similar terms as used by OPG) in its procurement tracking, reporting, RFP evaluation, supplier management, or Indigenous economic inclusion processes:

a) "Indigenous supplier";
b) "First Nation supplier";
c) "community-owned supplier";
d) "rightsholder-affiliated supplier";
e) "local supplier"; and
f) "diverse supplier".

Response

a) An Indigenous Business means a business that is at least 51% owned and controlled by Indigenous People. If the business is a partnership or joint venture, it must have at least 51% of the ownership rights (including any voting rights) directly held by one or more Indigenous Businesses, Indigenous People, or Indigenous Communities. Qualification is verified via certification by a recognized Equity, Diversity & Inclusion ("ED&I") council such as Canadian Council for Indigenous Business.

b) - d) OPG does not maintain formal, standalone definitions for the stated terms.

e) OPG does not maintain a formal, standalone definition for the term "local supplier." However, OPG aligns with the definition of an "Ontario Business" as set out in the Buy Ontario Procurement Directive:

An Ontario Business is defined as a supplier, manufacturer, or distributor of any business structure that conducts its activities on a permanent basis in Ontario and has either:

- its headquarters or main office located in Ontario; or

- at least 250 full-time employees in Ontario at the time of the applicable procurement process.

f) OPG defines a "Diverse Supplier" (ED&I Business) as a business that is at least 51% owned, operated, managed, or controlled by an individual(s) from equity-deserving groups and requires certification by a recognized ED&I council such as Canadian Women Owned Businesses.

UNDERTAKING JT1.2e

Undertaking

Reference: F3-MC-009
Reference: F3-MC-011
Reference: F3-MC-012

Question(s):

Please confirm whether OPG's existing procurement tracking, reporting, or record-keeping systems can disaggregate procurement award and spend data by:

a) facility, including Pickering, Darlington, and WWMF;
b) project, including DNNP, Pickering refurbishment, and
c) waste management-related work;
d) treaty area, including Williams Treaties and Treaty 45 ½;
e) rightsholder affiliation, including Williams Treaties First Nations and Treaty 45 ½ First Nations; and
f) supplier proximity to the relevant facility or project site.

If OPG's existing systems cannot disaggregate data in one or more of these ways, please explain the reason, including any technical, policy, governance, or data-quality limitations.

Response

a) and b) Confirmed.

c) - f) Not confirmed. OPG is unable to track this level of information in its systems. Refer to Ex. L-F3-MC-009.

UNDERTAKING JT1.2f

Undertaking

Reference: F3-MC-009
Reference: F3-MC-011
Reference: F3-MC-012

Question(s):

Please provide annual 2020-present contract award value and actual spend, to the extent available in OPG's existing records, for:

a) Indigenous suppliers;
b) First Nation community-owned suppliers;
c) rightsholder-affiliated suppliers;
d) suppliers affiliated with Williams Treaties First Nations;
e) suppliers affiliated with Treaty 45 ½ First Nations; and
f) Indigenous or rightsholder-affiliated subcontractors.

If OPG does not track one or more of these categories, please confirm that and explain how the available tracked categories differ from the categories listed above.

Response

a) OPG Indigenous spend reporting is publicly available in OPG's Annual Reports (refer to Ex. A2-1-1) and OPG's Corporate Balanced Scorecard (refer to Ex. L-F4-AMPCO-124 for the 2025 scorecard and Ex. JT5.21 for the 2021-2024 and 2026 scorecards).

   Over the 2021-2025 period, OPG has provided approximately $790M in awarded economic benefits and approximately $460M in actualized spends with Indigenous suppliers. This reporting is captured in OPG's annual Environmental, Social, and Governance reports on an total OPG basis. Refer to ESG & sustainability Report 2024 – OPG.

b) , c) and e) OPG does not track the referenced information. The categories currently tracked by OPG differ from the referenced categories. OPG tracks contract award value and actual spend in aggregate for Indigenous suppliers and specifically, for Indigenous-affiliated or rightsholder-affiliated subcontractors. Based on an internal assessment of the currently limited data on supplier treaty affiliation, OPG can also identify suppliers affiliated with known Williams Treaties First Nations.

d) OPG began tracking the referenced data in 2021 and is therefore unable to provide such data for 2020. Over the 2021-2025 period, OPG has provided approximately $90M in awarded economic benefits and approximately $50M in actualized spends with known Williams Treaties First Nation affiliated Indigenous Suppliers. This information is based on OPG's knowledge of supplier treaty affiliation.

f) Over the 2021-2025 period, OPG has provided approximately $320M in awarded economic benefits and approximately $240M in actualized spends with subcontracted Indigenous suppliers, which is inclusive of rightsholder-affiliated subcontractors. OPG cannot delineate all possible rightsholder-affiliated subcontractors based on the information collected.

UNDERTAKING JT1.2g

Undertaking

Reference: F3-MC-009
Reference: F3-MC-011
Reference: D3-MC-006

Question(s):

Please describe whether and how OPG tracks or retains information regarding the following and provide any existing reports, templates, or metrics used for this purpose, or identify where in OPG's procurement process these matters are recorded:

a) Indigenous engagement plans submitted as part of
b) RFP responses;
c) subcontracting commitments made by prime contractors to Indigenous, First Nation, community owned, or rightsholder-affiliated businesses;
d) actual subcontracting performance against those commitments;
e) supplier performance evaluation against Indigenous engagement commitments; and
f) any consequences, incentives, or corrective actions where actual performance differs from commitments.

Response

a) and b) OPG records and retains all relevant Indigenous engagement information within the contract file as part of the RFP process. Refer to parts c) - f) for a description of how contractual obligations, including Indigenous engagement plans, are tracked and managed.

c) - f) Procurements are recorded as contractual obligations and include, where applicable, subcontracting commitments made by prime contractors to Indigenous, First Nation, community-owned, or rightsholder-affiliated businesses, requirements to report on actual subcontracting performance against those commitments, supplier performance evaluation criteria related to Indigenous engagement, and any associated consequences, incentives, or corrective actions where actual performance differs from commitments. Both prime contractors and subcontractors are required to report monthly on their performance against established contractual commitments. This process to include an Indigenous engagement plan as part of contractual obligations is a recent addition to OPG's contracting methodology and will be incorporated into future agreements where applicable.

UNDERTAKING JT1.2h

Undertaking

Reference: D3-MC-005
Reference: D3-MC-006
Reference: F3-MC-011
Reference: F3-MC-012

Question(s):

Please describe how OPG's existing procurement process uses local Indigenous and First Nation rightsholder affiliated, or proximity-based procurement outcome data, if at all, when conducting procurement planning or supplier engagement for the 2027-2031 period, including in relation to:

a) supplier outreach strategies;
b) RFP design;
c) contract packaging or bundling decisions;
d) prequalification requirements;
e) subcontracting requirements or transparency measures;
f) procurement category strategies; and
g) facility-level or project-level procurement planning.

If such procurement outcome data is not used for one or more of the above purposes, please confirm that and explain what information OPG does rely on for those procurement planning decisions.

Response

OPG does not currently use local Indigenous and First Nation rightsholder-affiliated outcome data when conducting procurement planning or supplier engagement activities. Refer to Ex. L-D3-MC-005 and Ex. L-D3-MC-006 for information regarding the procurement evaluation process, as well as Ex. F3-3-1, Section 7 for information regarding "Social License and Procurement".

UNDERTAKING JT1.2i

Undertaking

Reference: D3-MC-006
Reference: D3-MC-007
Reference: F3-MC-012
Reference: F3-MC-013

Question(s):

Please describe whether OPG has undertaken any existing analysis, review, or assessment of procurement categories or contract opportunities for the 2027-2031 period that may be suitable for participation by Indigenous, local, or rightsholder-affiliated suppliers, including in relation to:

a) site services;
b) logistics;
c) maintenance;
d) monitoring;
e) waste-related services;
f) construction support services; and
g) professional or technical services.

If OPG has not undertaken such an analysis, please confirm whether suitability is considered in any other way within OPG's existing procurement evaluation, outreach, category management, or supplier engagement processes.

Response

OPG has not undertaken a specific analysis of procurement categories or opportunities for the 2027–2031 period based on suitability for Indigenous, local, or rightsholder-affiliated suppliers; however, OPG's existing procurement evaluation process incorporates consideration of Indigenous participation. Refer to Ex. L-F3-MC-009 and Ex. L-F3-MC-011 for details on procurement reporting and Indigenous economic inclusion, and Ex. L-D3-MC-005 for OPG's procurement evaluation process.

UNDERTAKING JT1.2j

Undertaking

Reference: D3-MC-006
Reference: F3-MC-012
Reference: F3-MC-013

Question(s):

Please describe how OPG's existing procurement, outreach, supplier engagement, Indigenous economic inclusion, or reporting processes account for the treaty area and rightsholder context of the OPG's facilities, including:

a) whether OPG differentiates between Williams Treaties and Treaty 45 ½ rightsholder communities for procurement outreach or reporting purposes;
b) whether facility-specific or treaty-area-specific supplier outreach is undertaken;
c) whether rightsholder affiliation is considered in RFP evaluation, Indigenous engagement plans, supplier development, or subcontracting commitments;
d) whether OPG reports internally on procurement outcomes connected to those treaty areas or rightsholder communities;
e) whether any legal, operational, safety, or procurement considerations affect how OPG accounts for treaty-area or rightsholder context; and
f) how these existing processes relate to OPG's RAP reporting, implementation of the Directive, and supplier engagement processes.

Response

a) and b) OPG considers all Indigenous rightsholder communities, including those associated with Williams Treaties and Treaty 45 ½, in its procurement outreach and engagement activities. OPG engages with Indigenous communities proximate to its existing and planned facilities to understand their interests, including potential business and procurement opportunities. Accordingly, supplier outreach is primarily undertaken on a facility and location-specific basis, while taking into account the interests of all relevant communities.

c) OPG confirms that it considers rightsholder affiliation in its RFP evaluation processes and Indigenous engagement plans, including in relation to supplier development initiatives and subcontracting commitments.

d) Refer to Ex. JT1.2e.

e) OPG follows its standard procurement policies and processes, which incorporate applicable legal, operational, safety, and procurement considerations. Refer to OPG's procurement process as described in Ex. F3-3-1.

f) OPG's procurement processes are designed to support its Reconciliation Action Plan commitments, applicable directives, and supplier engagement practices by embedding consistent consideration of Indigenous participation. Indigenous engagement is incorporated, where appropriate, into individual procurement planning, supplier development, and subcontracting expectations, supporting meaningful participation opportunities. OPG also maintains internal tracking and reporting of Indigenous procurement outcomes, which inform Reconciliation Action Plan reporting and continuous improvement. These processes are applied in a manner that reflects relevant legal, operational, safety, and procurement considerations, ensuring a consistent and practical approach to Indigenous supplier engagement.

UNDERTAKING JT1.3

Undertaking

Revise Chart 1, CMSC payments received and amounts recorded in SBGVA in E1-Staff-148 by replacing CMSC payments with only constrained-off CMSC payments, limited to OPG's hydroelectric base load facilities.

Response

OPG understands that the undertaking is intended to refer to all OPG's regulated hydroelectric facilities and not just baseload facilities. Set out below are the subset of constrained-off CMSC payments for the baseload regulated hydroelectric facilities, as well as for all other (non-baseload) regulated hydroelectric facilities.

In the course of preparing this undertaking response, OPG identified an error in its original response to Ex. L-E1-Staff-148 – total 2025 Jan-Apr CMSC payments received were $13.2M, not $12.8M.

Chart 1
Constrained-Off CMSC Payments Received[1] ($M)

Line No.	Constrained Off CMSCs – Regulated Hydroelectric	2020	2021	2022	2023	2024	2025 (Jan-Apr)
1	**Baseload[2]**	4.0	19.8	60.4	14.2	9.1	6.3
2	**All Remaining**	8.3	11.2	49.9	14.3	16.6	6.5
3	**Total[3]** (line 1 + line 2)	12.3	31.0	110.4	28.5	25.7	12.8

[1] Values include only CMSC payments received for energy and exclude any CMSC payments received for operating reserve.
[2] Baseload regulated hydroelectric stations are defined in Ex. L-A1-Staff-285.
[3] Numbers may not add due to rounding.

UNDERTAKING JT1.4

Undertaking

Update Chart 1 in E1-Staff-149 to include 2024 and 2025, going back to 2016.

Response

As discussed between Mr. Cincar and Mr. Chidiac at the Technical Conference[1], OPG is providing an update to Chart 1 of Ex. L-E1-Staff-149 to include data for 2016, 2017, 2018, 2024, and 2025, and to add a new row with total foregone regulated hydroelectric production due to surplus baseload generation ("SBG") consistent with Ex. L-E1-ED-011.

Chart 1 – Updated Historical Spill Amounts by Category (TWh)

	2016	2017	2018	2019	2020
Water conveyance constraints	0.7	1.2	1.5	2.1	2.8
Production capability	1.6	2.9	2.5	5.5	3.5
Market constraints	0.9	0.8	1.1	1.0	1.2
Contractual obligations	0.1	0.1	0.1	0.2	0.2
Foregone Production due to SBG	4.3	5.2	3.2	3.3	4.3
Total[2]	**7.6**	**10.2**	**8.5**	**12.1**	**12.0**

	2021	2022	2023	2024	2025
Water conveyance constraints	1.2	0.9	0.9	0.5	0.1
Production capability	1.9	3.3	2.6	2.1	2.2
Market constraints	1.3	2.0	1.4	0.9	0.2
Contractual obligations	0.2	0.2	0.2	0.2	0.2
Foregone Production due to SBG	1.9	1.6	1.0	0.3	0.8
Total	**6.6**	**8.1**	**6.0**	**4.0**	**3.4**

[1] Tr. Tech. Conf., May 27, 2026. p. 21, line 16 to p. 23, line 5.
[2] Numbers may not add due to rounding.

UNDERTAKING JT1.5

Undertaking

Provide the condition of assets for the completed project based on anything comparable to the health condition assessment ratings for all projects and SEC-41, Attachment 3.

Response

Attachment 1 provides, on a best-efforts basis as indicated at Tr. Tech. Conf., May 27, 2026, p. 60, lines 22-25, the status of asset condition at the time of project start for those projects identified as complete in Ex. L-D1-SEC-041, Attachment 3. As discussed in Ex. L-D1-SEC-041, E-Health is a live database used to document equipment condition in accordance with the Health Monitoring and Reporting process documented in Ex. L-D1-SEC-041, Attachment 1. E-Health reflects the current equipment health status and does not provide a historical assessment of asset condition, such as the condition prior to a project's initiation.

Given the age of the completed projects in Attachment 1, and that they predated the implementation of the process described in Ex. L-D1-SEC-041, Attachment 1, in order to respond to this undertaking, OPG reviewed available historical condition assessment reports and other supporting documentation. Engineering expertise and judgment were applied to evaluate asset condition ratings in a manner consistent with the health condition assessment ratings provided in Ex. L-D1-SEC-041, Attachment 3. Pre-project asset condition ratings were derived from documentation available from the respective time period; current E-Health data was not used to infer historical condition. Where insufficient verifiable information existed to support a rating, the condition has been identified as "unknown", with a justification provided. These ratings are presented in Attachment 1 for comparative and summary purposes and are subject to the limitations of the available historical records.

Project Name	Classification	Summary of Major Assets in Project Scope	Current Condition of Major Assets	Project Status	Condition Prior to Project[1]
82089 Calabogie Generating Station - Redevelopment	Capital	Generator System: - stator: install new - rotor: install new - generator bearings: install new - condition monitoring: install new Hydro Turbine: - runner: install new - bearing(s): install new - water passage and embedded parts: install new - operating mechanism:install new - condition monitoring: install new Turbine Regulation System: install new Medium Voltage Equipment: install new Excitation System: install new Unit Protections and Controls: install new Power Transformers: Install new - main output transformers: install new - station service transformers: install new Conveyance Structures: install new Intake and Headworks System: install new Powerhouse: install new	Current Condition (post project): Generator System: good - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: good - runner: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: fair - condition monitoring: good Turbine Regulation System: good Medium Voltage Equipment: good Excitation System: good Unit Protections and Controls: good Power Transformers: good - main output transformers: good - station service transformers: good Conveyance Structures: good Intake and Headworks System: good Powerhouse: good	Closed	Condition Prior to Project Start[2]: Generator System: - stator: PCA = fair, post-tornado = not documented - rotor: PCA = fair, post-tornado = not documented - generator bearings:PCA: fair, post-tornado: not documented - condition monitoring: N/A Hydro Turbine: - runner: PCA = poor, post-tornado: not documented - bearing(s): PCA = poor, post-tornado: not documented - water passage and embedded parts: PCA = poor, post-tornado: not documented - operating mechanism: PCA = good, post-tornado: not documented - condition monitoring: N/A Turbine Regulation System: PCA = good, post-tornado = not documented Medium Voltage Equipment: PCA = fair, post-tornado: not documented Excitation System: PCA = poor, post-tornado = not documented Unit Protections and Controls: PCA = poor, post-tornado = not documented Power Transformers: - main output transformers: PCA = fair, post-tornado: not documented - station service transformers: PCA = good, post-tornado: not documented Conveyance Structures: poor (due to tornado damage) Intake and Headworks System: PCA = fair, post-tornado: not documented Powerhouse: PCA = fair, post-tornado = unacceptable

80851 Decew Falls 2 Generating Station - G2 Overhaul[3] & Upgrade	Capital	Generator System: - stator: install new - rotor: install new - generator bearings: install new - condition monitoring: install new Hydro Turbine: - runner: Re-use existing. minor repairs - headcover: refurbish - bearing(s): refurbish - water passage and embedded parts: refurbish - operating mechanism: refurbish - condition monitoring: install new Turbine Regulation System: refurbish Medium Voltage Equipment: refurbish Excitation System: install new Unit Protections and Controls: refurbish / install new where necessary to accomodate new equipment Power Transformers: - main output transformers: minor modifications	Current Condition (post project): Generator System: good - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: fair - runner: unacceptable - headcover: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: poor - condition monitoring: good Turbine Regulation System: fair Medium Voltage Equipment: fair Excitation System: good Unit Protections and Controls: fair Power Transformers: good - main output transformers: good	Closed	Condition Prior to Project Start Generator System: - stator: poor - rotor: good to fair - generator bearings: good - condition monitoring: N/A Hydro Turbine: - runner: fair - headcover: unknown - bearing(s): good to fair - water passage and embedded parts: fair to good - operating mechanism: fair - condition monitoring: n/a Turbine Regulation System: good to fair Medium Voltage Equipment: poor Excitation System: fair Unit Protections and Controls: poor to fair Power Transformers: - main output transformers: good
84185 Sir Adam Beck 1 - G1/G2 Replacement	Capital	Generator System: - stator: install new - rotor: install new - generator bearings: install new - condition monitoring: install new Hydro Turbine: - runner: install new - headcover: install new - bearing(s): install new - water passage and embedded parts: install new - operating mechanism: install new - condition monitoring: install new Turbine Regulation System: install new Medium Voltage Equipment: Excitation System: install new Unit Protections and Controls: install new Power Transformers: - main output transformers: install new Conveyance Structures: inspect and refurbish Intake and Headworks System: - Headgates: refurbish	Current Condition (post project): Generator System: good - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: good - runner: good - headcover: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: good - condition monitoring: good Turbine Regulation System: good Medium Voltage Equipment: good Excitation System: good Unit Protections and Controls: good Power Transformers: good - main output transformers: good Conveyance Structures: good Intake and Headworks System: fair	Closed	Condition Prior to Project Start[4]: Generator System: N/A - stator: N/A - rotor: N/A - generator bearings: N/A - condition monitoring: N/A Hydro Turbine: - runner: N/A - headcover: N/A - bearing(s): good - water passage and embedded parts: good - operating mechanism: fair - condition monitoring: N/A Turbine Regulation System: N/A Medium Voltage Equipment: N/A Excitation System: N/A Unit Protections and Controls: N/A Power Transformers: - main output transformers: N/A Conveyance Structures:good to fair Intake and Headworks System: good

80583 Sir Adam Beck Pump Generating Station - Reservoir Refurbishment	Capital	Reservoir: refurbish	Current Condition (post project): Reservoir: good	Closed	Condition Prior to Project Start: Reservoir: unacceptable
80649 Sir Adam Beck I Generating Station - G10 Major Overhaul[3] & Upgrade	Capital	Generator System: - stator: rewind - rotor: refurbish - generator bearings: install new - condition monitoring: install new Bently Nevada system Hydro Turbine: - runner: install new - headcover: install new - bearing(s): refurbish - water passage and embedded parts: Refurbish - operating mechanism: install new - condition monitoring: install new Bently Nevada system Turbine Regulation System: install new governor controls Medium Voltage Equipment: install new disconnect switch Excitation System: install new Unit Protections and Controls: install new Power Transformers: - main output transformers: install new Conveyance Structures: inspect and repair as required	Current Condition (post project): Generator System: good - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: good - runner: fair - headcover: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: good - condition monitoring: good Turbine Regulation System: fair Medium Voltage Equipment: good Excitation System: good Unit Protections and Controls: good Power Transformers: good - main output transformers: good Conveyance Structures: good	Closed	Condition Prior to Project Start: Generator System: - stator: fair to poor - rotor: fair to poor - generator bearings: good - condition monitoring: N/A Hydro Turbine: fair - runner: fair to poor - headcover: unknown - bearing(s): unknown - water passage and embedded parts: good - operating mechanism: unknown - condition monitoring: N/A Turbine Regulation System: fair Medium Voltage Equipment: fair to poor Excitation System: fair to poor Unit Protections and Controls: fair to poor Power Transformers: - main output transformers: poor Conveyance Structures: fair to poor

80581 Ranney Falls Generating Station - Expansion Project	Capital	Generator System: - stator: install new - rotor: install new - generator bearings: install new - condition monitoring: install new Hydro Turbine: - runner: install new - headcover: install new - bearing(s): install new - water passage and embedded parts: install new - operating mechanism: install new - condition monitoring: install new Turbine Regulation System: install new Medium Voltage Equipment: install new Excitation System: install new Unit Protections and Controls: install new Power Transformers: - main output transformers: install new - station service transformers: install new Intake and Headworks System: install new	Current Condition (post project): Generator System: - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: - runner: good - headcover: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: good - condition monitoring: good Turbine Regulation System: good Medium Voltage Equipment: good Excitation System: fair Unit Protections and Controls: good Power Transformers: - main output transformers: good - station service transformers: good Intake and Headworks System: good	Closed	As this is a new unit at the existing station, there are no previous equipment conditions to document.
82777 Sir Adam Beck 1 Generating Station - Unit G5 Upgrade	Capital	Generator System: - stator: minimal refurbish - rotor: refurbish - generator bearings: refurbish Hydro Turbine: - runner: install new - headcover: install new - bearing(s): refurbish - water passage and embedded parts: install new - operating mechanism: install new Medium Voltage Equipment: install new disconnects Excitation System: install new Unit Protections and Controls: install new Power Transformers: - main output transformers: install new Conveyance Structures: inspect Intake and Headworks System: inspect and minor repair	Current Condition (post project): Generator System: good - stator: good - rotor: fair - generator bearings: good Hydro Turbine: good - runner: good - headcover: good - bearing(s): fair - water passage and embedded parts: good - operating mechanism: good Medium Voltage Equipment: good Excitation System: good Unit Protections and Controls: good Power Transformers: - main output transformers: good Conveyance Structures: good Intake and Headworks System: good	Closed	Condition Prior to Project Start: Generator System: - stator: good - rotor: poor - generator bearings: fair Hydro Turbine: fair to poor - runner: fair - headcover: poor - bearing(s): poor - water passage and embedded parts: fair / not fully assessed - operating mechanism: fair to poor Medium Voltage Equipment: poor Excitation System: poor Unit Protections and Controls: poor Power Transformers: - main output transformers: poor Conveyance Structures: fair Intake and Headworks System: good

83155 Abitibi Canyon Generating Station - G2 Capital Upgrades/HG	Capital	Generator System: - stator: refurbish stator, install new windings - rotor: refurbish poles, install new spider - generator bearings: refurbish guide, install new thrust - condition monitoring: refurbish Hydro Turbine: - runner: refurbish - headcover: refurbish - bearing(s): refurbish - water passage and embedded parts: refurbish - operating mechanism: refurbish - condition monitoring: refurbish Turbine Regulation System: refurbish Excitation System: install new Intake and Headworks System: install new headgate and hoist	Current Condition (post project): Generator System: good - stator: good - rotor: good - generator bearings: good - condition monitoring: good Hydro Turbine: good - runner: fair - headcover: good - bearing(s): good - water passage and embedded parts: good - operating mechanism: good - condition monitoring: good Turbine Regulation System: good Excitation System: good Intake and Headworks System: good	Closed	Condition Prior to Project Start: Generator System: - stator: fair to poor - rotor: unknown - generator bearings: poor - condition monitoring: N/A Hydro Turbine: - runner: unknown - headcover: fair to good. - bearing(s): poor - water passage and embedded parts: poor - operating mechanism: fair to poor - condition monitoring: N/A Turbine Regulation System: unknown Excitation System: condition: fair Intake and Headworks System: poor
82328 Otto Holden Generating Station - Concrete Mitigation	OM&A	Intake and Headworks System: - substructure: (intake piers and embedded components, deck, hatches, covers): rehabilitate - superstructure (columns, roof framing and walls): rehabilitate - stairs and railings: rehabilitate Powerhouse: - building envelop: rehabilitate - superstructure: rehabilitate - substructure: rehabilitate - Tailrace Structure System: - concrete deck: rehabilitate Dam Structure: - upstream face: rehabilitate	Current Condition (post project): Intake and Headworks System: - substructure: (intake piers and embedded components, deck, hatches, covers): good - superstructure (columns, roof framing and walls): good - stairs and railings: good Powerhouse: - building envelop: good - superstructure: good - substructure: good Tailrace Structure System: - concrete deck: good Dam Structure: - upstream face: good	Closed	Intake and Headworks System: - substructure: (intake piers and embedded components, deck, hatches, covers): intake piers = poor, deck = poor - superstructure (columns, roof framing and walls): fair to poor (concrete deteriation and cracking on walls, beams and vertical joints) - stairs and railings: railings = fair to poor (varies by location, railings must be removed to repair deck) Powerhouse: - building envelop: roofs (fair to poor - varies by location), windows (vary in age and location, fair to poor), concrete walls (fair) - superstructure: generator floor (good to poor, depending on location and extent of AAR), steel frames (fair) - steel frames installed to support grating covers, upstream/downstream walls (fair - project scope included repair to damaged/cracked or deteriorated locations) - substructure: floor beams (fair) - reinforcement of floor beams required in advance of unit overhauls Tailrace Structure System: - concrete deck: deck grating and steel frames (poor) Dam Structure: - upstream face: poor

Notes:

1. Historical project that pre-dated current health monitoring process. As such, pre-project condition assessements are provided on a best-efforts basis; refer to Ex. JT1.05.

2. A Plant Condition Assessment (PCA) was completed for Calabogie GS in 2011. In September 2018, the site was severly damaged by a tornado, resulting in significant damage to the powerhouse and sluiceway equipment. Following the tornado, the site was assessed for the purpose of safe-stating due to the damage to the powerhouse and equipment exposed to the elements. The decision to redevelop the site with a new generating station was supported by the Conceptual Design Alternatives Selection report, however, the post-tornado condition was not documented for all components.
3. Legacy project that predates current terminology. Project scope consistent with a refurbishment (capital).
4. The SAB1 GS G1/G2 units were previously decomissioned. Significant upgrades were required to have the equipment operate at 60 Hz (previous the units were operating at 25 Hz).

UNDERTAKING JT1.6

Undertaking

Advise how many outage days OPG estimates as a result of replacement of electrical common balance plant of work for each of the G20, G19, G18, G17, G14, and G13 projects.

Response

OPG understands this undertaking is to provide an estimate of how many incremental outage days would be incurred if the common electrical balance of plant scope for the referenced Sir Adam Beck 2 GS units was completed outside of the respective refurbishment project outage.

The common electrical balance of plant scope in Project #87768 Sir Adam Beck 2 GS G20/19 Refurbishment, Project #87356 Sir Adam Beck 2 GS G18/17 Refurbishment, and Project #87357 Sir Adam Beck 2 GS G14/13 Refurbishment includes the replacement of the main output transformers, protection and control system, isolated phase bus, and associated cabling.

Completing this work during a dual unit refurbishment outage, as OPG has planned, reduces risk, improves work efficiency, and optimizes refurbishment outage time because it allows OPG to execute such shared unit scope once, in a coordinated work window, without adding time to critical path. This reduces rework, simplifies work protection, and avoids additional forgone generation that would otherwise arise from this common-equipment scope if the refurbishments were unpaired. If the common balance of plant electrical scope was completed in a separate, distinct outage, OPG would need to repeat isolations, mobilization, testing and commissioning while temporarily integrating new common systems with existing unit equipment that would later require re-integration. OPG estimates that an equivalent of an incremental 386 dual unit outage days would be required to complete this work for the above three projects if it were executed separately from the rest of the refurbishment project scope. In this hypothetical circumstance, OPG would still complete this work as part of a dual unit outage for work efficiency reasons.

For clarity, there are other efficiencies associated with performing the refurbishment projects in unit pairs, in addition to the electrical common balance of plant scope.

UNDERTAKING JT1.7

Undertaking

Provide a probability of failure for any relevant and important project that OPG can provide as an example of how it is assessed and how it can be used to analyze certain issues.

Response

In accordance with the Engineering Risk Assessment Program provided at Ex. L-D1-SEC-041, Attachment 2, OPG assesses risks associated with degraded/degrading condition of assets. As part of this process, OPG Engineering staff considers probability and consequence of failures to define the risk. These risk scores are captured over four time periods (0-5 years, 6-10 years, 11-15 years, 16-40 years). Depending on risk level (Very High, High, Medium, Low), risk treatment plans and bridging strategies are developed following guidance outlined in the program governance, and include both short-term and long-term actions. The design of risk treatment plans takes into consideration how the risk profile is expected to change over time. Where a risk requires an investment to be mitigated, the Renewable Generation business unit follows the process outlined in Ex. D2-1-1, Section 3.2.

Oversight of risks is provided through Plant Health Committee. Sample Plant Health Committee presentation material is provided at Ex. JT1.17, Attachment 1 (confidential) as reference to illustrate the forum through which plant health condition and risks are reviewed, response strategies are endorsed, and follow-up actions are monitored.

For the purposes of this response, OPG has selected Project #87356 Sir Adam Beck 2 GS – G18/G17 Refurbishment as a “relevant and important project” to demonstrate the risk assessment process (details on this project are provided at Ex. D1-1-2, pp.20-21).

Chart 1 summarizes multiple risk assessments for Sir Adam Beck 2 GS associated with various equipment conditions of Units G17 and G18 with respect to Lost Generation and Financial Impact risk categories. The chart shows the baseline risk score resulting from the associated consequences and probabilities of failure. This information is used to compare issues across equipment groups, identify the highest-risk contributors for the station, and assess whether interim mitigation, continued monitoring, or project investment is needed.

Chart 1 – Risk Evaluation Examples (Sir Adam Beck 2 GS; Units G17, G18)

Item	Baseline Risk Score*		Consequence of Failure (0-5 years)	Probability of Failure (0-5 years)
BK2-23-0002 – G17 and G23 High Turbine z-axis Vibration (Turbine)	1068	Lost Generation: 963	“L3” ($1M - $10M)	Likely 10% - 25%
		Financial Impact: 105	"L2" ($200k - $1M)	Likely 10% - 25%
BK2-23-0011 – Aging Brush Gear, Insulation Failure (Generator)	1926	Lost Generation: 963	“L3” ($1M - $10M)	Likely 10% - 25%
		Financial Impact: 963	“L3” ($1M - $10M)	Likely 10% - 25%
BK2-23-0009 – Noisy Aged Exciters with High Runout Values (Excitation)	1926	Lost Generation: 963	“L3” ($1M - $10M)	Likely 10% - 25%
		Financial Impact: 963	“L3” ($1M - $10M)	Likely 10% - 25%
BK2-24-0007 – SAB2 Transformer and Generator Protection Relay (Unit Protection and Control System)	13126	Lost Generation: 6563	"L4" ($10M - $25M)	Probable 25% - 50%
		Financial Impact: 6563	"L4" ($10M - $25M)	Probable 25% - 50%
BK2-24-0003 – Leaking Transformers SAB2 (Power Transformers)	330	Lost Generation: 165	“L3” ($1M - $10M)	Unlikely (1% - 5%)
		Financial Impact: 165	“L3” ($1M - $10M)	Unlikely (1% - 5%)

*For the purpose of this exercise on probability of failure, Social License, Environmental, and Safety risks were not included in the Base Line Risk Score.

A sample calculation demonstrating the derivation of a baseline risk score is provided as follows:

Sample Calculation: LCM# BK2-23-0002 (High Turbine Z-Axis Vibration)

Total baseline score (total risk rank) is calculated as follows:

$$Total\ Risk\ Rank = \sum Risk\ Values_i$$

$$where\ Risk\ Value = (Midpoint\ Probability) \times (Midpoint\ Consequence\ Value)$$

As shown in Chart 1, risk evaluations are captured for Lost Generation and Financial Impact risk categories. Therefore, total risk rank is calculated as follows:

$$Total\ Risk\ Rank = \sum Risk\ Values_i = Risk\ Value_{Lost\ Generation} + Risk\ Value_{Financial}$$

<u>Risk Value (Lost Generation):</u>

$$Risk\ Value_{Lost\ Generation} = (Midpoint\ Probability)_{L.G.} \times (Midpoint\ Consequence\ Value)_{L.G.}$$

In accordance with governance, OPG Engineering assigned a probability and consequence of failure as {“Likely” 10%–25%} and {“L3” ($1M – $10M)} respectively.

$$Risk\ Value_{Lost\ Generation} = \left(\frac{0.10 + 0.25}{2}\right) \times \left(\frac{1{,}000k + 10{,}000k}{2}\right)$$

$$Risk\ Value_{Lost\ Generation} = (0.175) \times (5{,}500) = 963$$

The risk value of 963 corresponds to a medium risk.

<u>Risk Value (Financial Impact):</u>

$$Risk\ Value_{Financial} = (Midpoint\ Probability)_{Fin.} \times (Midpoint\ Consequence\ Value)_{Fin.}$$

In accordance with governance, OPG Engineering assigned a probability and consequence of failure as {“Likely” 10%–25%} and {“L2” ($200k - $1M)} respectively.

$$Risk\ Value_{Financial} = \left(\frac{0.10 + 0.25}{2}\right) \times \left(\frac{200k + 1{,}000k}{2}\right)$$

$$Risk\ Value_{Financial} = (0.175) \times (600) = 105$$

The risk value of 105 corresponds to a low risk.

Total Risk Value:

$$Total\ Risk\ Rank = \sum Risk\ Values_i = Risk\ Value_{Lost\ Generation} + Risk\ Value_{Financial}$$

$$\therefore Total\ Risk\ Rank = 963 + 105 = 1068$$

The overall risk value of 1,068 corresponds to a medium risk.

UNDERTAKING JT1.8

Undertaking

Advise what condition Alexander GS Units G4 and G5 are in and when they will be refurbished.

Response

Alexander GS Unit G4 was refurbished/overhauled in 2012 and Unit G5 in 2010. As a result, Units G4 and G5 are in good condition as outlined in the 2022 Alexander GS Condition Assessment (provided at Ex. L-D1-Staff-309, Attachment 3). The next refurbishment/overhaul projects are tentatively expected to take place in 2045 for Unit G4 and 2044 for Unit G5, which timeline is subject to update through OPG's asset management planning processes.

UNDERTAKING JT1.9

Undertaking

Confirm when the OPG Board of Directors approved the use of unallocated portfolio in business planning for the renewable generation business unit and when OPG started implementing it in their business planning.

Response

Through the company's business planning processes, OPG's Renewable Generation business unit ("RG") always reviewed investment needs for its project portfolio, including potential projects that did not yet have an approved Business Case Summary, and OPG's Board of Directors always approved such capital budgets. RG would adjust its business plans as new projects were identified or investment needs otherwise evolved, seeking to manage its capital expenditures while ensuring ongoing safety and reliability of the fleet. In aligning the management of its project portfolios with the processes outlined Ex. D2-1-1, RG has formalized the categorization and management of an unallocated portfolio as part of the 2025-2031 Business Plan in recognition, in part, of the more extensive capital program and a longer business planning and rate-setting horizon.

UNDERTAKING JT1.10

Undertaking

Provide a narrative that describes the main drivers of the difference in cost between the G16 and G12 refurbishment by category as seen in Chart 3, cost breakdown per unit, on page 5 of the interrogatory response.

Response

Since providing the response to Ex. L-D1-Staff-068, OPG has identified that additional funding will be required to complete the R.H. Saunders Unit G12 ("Unit G12") capital refurbishment (Project #86587).

The additional costs required to complete the Unit G12 capital refurbishment are detailed in the Superseding Business Case Summary ("BCS") provided as Attachment 1 (confidential). A cost comparison between the respective capital refurbishments per the First Execution BCS for Unit G12, the Superseding Execution BCS for Unit G12 and the First Execution BCS for R.H. Saunders Unit G16 ("Unit G16") is provided in Chart 1 below.

Chart 1 – Summary Cost Breakdown per R.H. Saunders GS Unit

Unit	Unit G12 ($M)	Unit G12 ($M)	Unit G16 ($M)
	1st CWC	1st CWC	2nd CWC
BCS Status	First Execution	Superseding	First Execution
Class of Estimate	Class 3	Class 3	Class 3
Project Management and Engineering	[redacted]		
Procurement			
Construction			
Subtotal			
Contingency			
Subtotal w/ Contingency			
Interest			
Total	**30.4**	**46.8**	**49.3**

Note: Numbers may not add due to rounding.

The specific cost drivers between the Unit G12 First Execution BCS and the Superseding Execution BCS are summarized below and detailed in Chart 2 below.

The cost variance is primarily attributable to the incorporation of lessons learned from the first capital refurbishment project at R.H. Saunders, for Unit G9 ("Unit G9", Project #83495) and Unit G12 specific discovery work. The application of lessons and specific discoveries resulted in a longer-than-planned project schedule and increased requirements for project management, engineering, and construction support resources for Unit G12.

The Unit G12 execution cost estimate incorporated lessons learned from Unit G9 up to Q2 2024, when the First Execution BCS was approved (refer to Ex. L-D1-Staff-068). While the First Execution BCS estimate for Unit G12 relied on the best available information, Unit G9 was still under construction at the time and therefore the estimate did not yet reflect the full extent of lessons learned related to the Unit G9 construction challenges as they were realized after Q2 2024.

Unit G9 lessons learned, construction challenges, and cost variances are discussed in Ex. D1-1-2, p. 25, lines 19–26, and in Ex. L-D1-Staff-067.

Unit G12 is the first Canadian Westinghouse Company ("CWC") unit to undergo refurbishment as part of the R.H. Saunders GS refurbishment program, representing a first-of-a-kind project for this design, as discussed in Ex. L-D1-Staff-068. Unit G12 has experienced unit-specific construction challenges resulting in discovery driven changes, including scroll case concrete repairs, outer headcover refurbishment delays, installation related learnings, and design changes requiring rework, such as control panel modifications, cable tray routing updates, and piping arrangement adjustments.

Chart 2 – Cost Variance Summary between the First Execution BCS and the Superseding Execution BCS for R.H. Saunders G12 Refurbishment Project

Item	Detail	Cost ($M)
Project Management and Engineering	Additional project management costs in support of Unit G9 applied lessons and Unit G12 construction challenges	[redacted]
	Additional engineering costs in support of Unit G9 applied lessons and Unit G12 construction challenges	[redacted]
Procurement	Additional procurement costs relating to construction challenges including unit control panel changes	[redacted]

Item	Detail	Cost ($M)
Construction	Additional costs driven by Unit G9 applied lessons and Unit G12 construction challenges from as-found conditions resulting in discovery work	[redacted]
Other	Additional interest costs driven by increased overall project cost	[redacted]
Subtotal		[redacted]
Contingency	Available contingency modeled through risks probability and consequence	[redacted]
Total		**16.4**

Note: Numbers may not add due to rounding.

The cost difference between Unit G12 and Unit G16 capital refurbishments is detailed in Chart 3. The Unit G16 first execution estimate incorporates lessons learned from the completion of Unit G9 and progress on Unit G12 up to Q4 2025, when the First Execution BCS for Unit G16 was approved, as discussed in Ex. L-D1-Staff-068.

Chart 3 – Details of Cost Difference between R.H. Saunders G12 and G16 Refurbishment Projects

Item	Difference ($M)	Detail
Project Management and Engineering	[redacted]	Unit G16 requires lower project management and engineering costs resulting from a three-month shorter outage duration, design replication and forecast efficiencies from refurbishing a second CWC unit. These reductions are partially offset by increased engineering costs to design a new headcover, and cost escalation due to passage of time.
Procurement	[redacted]	Unit G16 requires higher procurement costs due to a bearing design change from Polytetrafluoroethylene (“PFTE”) to Polyether ether keytone (“PEEK”), and cost escalation due to passage of time.
Construction	[redacted]	Unit G16 requires lower construction costs resulting from a three-month shorter outage duration and expected trade staff efficiencies from refurbishing a second CWC unit, offset by cost escalation due to passage of time.

Item	Difference ($M)	Detail
Contingency	[redacted]	Unit G16 requires higher contingency because it reflects the full range of project risks across the full project duration including any lessons to be learned from the remaining Unit G12 construction. Unit G12 is closer to completion and has fewer remaining risks, resulting in lower expected potential consequences.
Interest	[redacted]	
Total	**2.5**	

Note: numbers may not add due to rounding.

ONTARIO POWER GENERATION

Records File Information:
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OPG-FORM-0076-R006*

Business Case Summary

Project #	86587, 86593	**BCS Document Number**	NA9-BCS-08707-1805964
Project Title	86587 - SAU - G12 CAPITAL REFURBISHMENT 86593 - SAU - G12 OVERHAUL		
Facility	SAU - RH SAUNDERS	**Investment Classification**	Sustaining
Project Level (Scalability)	B	**Financial Classification**	17553 - CAPITAL - GENERATING FACILITIES 62030 - OM&A - PROJECT
Release: Gate and Project Phase	G3 - Execution - (Superseding)	**Target Project Completion Date**	2027-Aug-27
Estimate Class (Current Request)	Class 3	**Estimate Class (Overall Project)**	Class 3

Recommendation

We recommend a release of $15,665k, including [redacted] of contingency. As part of this release, $745k will be transferred from the OM&A project 86593 to the Capital project 86587. Following the transfer, the project specific release (including contingency) is as follows:

SAU86587 (Capital): $16,410k, including [redacted] of contingency
SAU86593 (OM&A): ($745k), including [redacted] of contingency

This will bring total release to-date to $56,981k, including [redacted] of contingency, compared to $41,316k in the previous release.

The total bundled project cost is $56,981k, (Capital $46,790k & OM&A $10,191k) including [redacted], (Capital [redacted] & OM&A [redacted]) of contingency.

These two projects are for the refurbishment/overhaul of Generator Unit 12 at R.H. Saunders Generating Station. This release will fund the remaining execution scope of work to restore the integrity, reliability and long-term viability of this generator.

Remaining scope includes the following:

- Unit reassembly remaining scope
- Electrical & mechanical systems remaining installation
- Testing & Commissioning activities
- Project and site management
- Engineering oversight and quality control
- Project closeout

Investment Cash Flows

Project Number	86587 - SAU - G12 CAPITAL REFURBISHMENT	**FAC**	17553 - CAPITAL - GENERATING FACILITIES

$K	**LT YE last year**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Future**	**Total**
Previous releases	27,622	2,758							30,380
Currently Requested	0	16,349	61						16,410
Total released to date	27,622	19,107	61						46,790
Future required	0								0
Total Project Cost	27,622	19,107	61						46,790
Ongoing Costs	0								0

Project Number	86593 - SAU - G12 OVERHAUL	**FAC**	62030 - OM&A - PROJECT

ONTARIO POWER GENERATION

Records File Information:
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Business Case Summary

$K	LT YE last year	2026	2027	2028	2029	2030	2031	Future	Total
Previous releases	9,435	1,501							10,936
Currently Requested		-745							-745
Total released to date	9,435	756							10,191
Future required									
Total Project Cost	9,435	756							10,191
Ongoing Costs									

Total OAR Approval	56,981.0

Approvals	Signatures	Date
The recommendation, including the identified ongoing costs, if any, represents the best option to meet the validated business need.		
Recommended by: Direct Report of Line Approver : Brian Dietrich SVP Renewable Generation& Energy Markets SVP RG & PM	Brian Dietrich	2026-06-08
I concur with the business decision as documented in this BCS.		
Finance Approval : Michael Gore SVP Chief Controller & Acctng Offcr	Michael Gore	2026-06-09
I confirm that this investment/project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.		
Line Approval per OAR : OAR Element : 1.1 Shelley Babin Chief Operations Officer	Shelley Babin	2026-06-09

EXECUTIVE SUMMARY – Project Overview

R.H. Saunders Generating Station (GS) is a "Flagship" asset of OPG's fleet of hydroelectric stations, providing 1045MW of emissions free energy to Ontario. The most recent mechanical and electrical refurbishment/overhaul of the turbine and generators (all 16) were completed during the 1990s and early 2000s. Components included in the last refurbishment/overhaul project are nearing end of life and require refurbishment or replacement in order to meet the project objectives of:

- Restore integrity, long-term reliability and ensure the continued availability of the generating units at RH Saunders GS
- Address deteriorating condition of the components (discussed in detail below)
- Re-establish rotor-stator air gap and runner-discharge ring clearances
- Reduce risk of thrust bearing failures

The preferred alternative is the refurbishment/overhaul of each unit with individual project number for a Capital and OM&A release for each generator unit. The OM&A overhaul G12 (SAU86593) project scope includes significant cleaning and repairs of generator and turbine components. The capital refurbishment G12 (SAU86587) project scope will include system upgrades and new installation.

The previous releases funded detailed design, material and equipment procurement, unit disassembly, unit component refurbishment activities, new system installations and unit reassembly. This superseding execution release will fund the remaining unit reassembly, system testing, unit commissioning and closeout costs.

The additional funding request is to address the actual cost and schedule requirements from implementing the lessons learned from the G9 project, which were not available prior to the initial Gate 3 execution estimate. This includes discharge ring modifications, stay ring machining and additional work required on the turbine components which were in worse condition than expected. Furthermore, Unit G12, while the second unit to be refurbished, is the first Canadian Westinghouse unit, resulting in new discovery work that required additional design and construction changes to meet approved objectives. Redesign was required for the thrust bearing, cable trays and high pressure oil lift system. As a result, the extended timeline increased the level of internal and vendor project management and engineering support needed, along with greater effort for reassembly, rehabilitation, and commissioning activities.

Top Risk(s):

1. Bearing failure during commissioning, due to potential contamination in the thrust bearing oil and/or issues with bearing installation or startup procedures resulting in schedule delays and additional costs. Project has strengthened control of foreign material exclusion process, validated startup procedures with manufacturer requirements and installed a new oil lift system to mitigate this risk.

Business Need	For Project Level A or B

Business Case Summary

Major work on turbine-generator units falls into two categories: overhauls and refurbishments. Overhaul projects are typically required every 25-30 years and involve significant OM&A maintenance activities to sustain reliable operations of the turbine-generator equipment and related systems. Refurbishment projects are capital investments aimed at extending the lifespan of the equipment. Refurbishments may also include technological improvements. The most recent mechanical and electrical refurbishment/overhauls of the G12 turbine and generator were completed during the 1990s and early 2000s. The turbine and generator components have experienced unique operational issues and structural damage for many years, such as reduced generating unit clearances, discharge ring deformation, concrete structure cracking, relative movement of structural members, and powerhouse water leakage. These issues are either caused or have been exacerbated by Alkali-Aggregate Reaction (AAR), which is a chemical reaction that induces concrete growth.

A Pre-Overhaul Condition Assessment was finalized in 2016, which examined major water-to-wire electrical, mechanical and civil equipment and structures to provide a basis for this project scope. From the technical condition assessment and validated through the continuous equipment health monitoring process, the following major work was recommended on all units at the R.H. Saunders GS:

SAU86587 G12 Refurbishment Scope:
Generator System:
- Rotor: refurbish field poles
- Generator bearings: upgrade thrust bearing, refurbish guide bearing
- Condition monitoring: install new
Hydro Turbine:
- Runner: install new
- Bearing: refurbish
- Water passage and embedded parts: new pivot ring and discharge ring
- Operating mechanism: install new servomotors
- Condition monitoring: install new
Turbine Regulation System:
- Governor system: refurbish

SAU86593 G12 Overhaul Scope:
Hydro Turbine:
- Headcovers: refurbish
- Stay Vanes & Wicket Gates: refurbish
- Shift ring: refurbish
Water Passage:
- Scroll case & draft tube: concrete inspection, repair, grouting and sealing.

New runner was procured under a separate capital project, SAU83104 and was installed concurrently with this project in the refurbishment outage.

Preferred Alternative:	Complete G12 Refurbishment with additional budget	For Project Level A, B or C

Description of Preferred Alternative

It is recommended to proceed with completing the G12 refurbishment by securing additional budget to finish the work and return G12 to service. Completing the project will restore reliability to end-of-life components and systems and will meet the stated project objectives.

Deliverables:

Previous Release:

Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Notice to Proceed to General Contractor	Award Contracts / PO Issued		2024-06-03
Start of Pre-Construction	Start of Construction		2024-08-28
Start of Outage & Installation (SOO)	Start of Outage		2024-09-23
Start of Commissioning	Commissioning Start		2026-02-20
Reassembly Finish	Finish of Installation		2026-03-30

Business Case Summary

Current Release:			
Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Gate 3 SBCS Approval	Gate G3 Approval		2026-05-29
Commissioning Finished	Commissioning Finished		2026-08-26
Available for Service (AFS)	Available for Service and/or Ready For Service Completed		2026-08-28
Project Complete	Project Close Out Completed		2027-08-27
Future Release: N/A			

Alternative 2:	**Base Case - No Project** For Project Level A, B or Value-Enhancing
This alternative is not viable because G12 has not been returned to service, and the available funding has been exhausted.	
Alternative 3:	**Delay Work** For Project Level A, B or Value-Enhancing
This alternative is not viable because G12 has been reassembled and must be commissioned and return to service to begin generating electricity and to place new capital assets into service, thereby realizing the project's intended benefit.	
Alternative 4:	For Project Level A, B

Key Risk Assessment			For Project Level A, B or C
Risk Class	**Description of Risk**	**Response Type / Actions / Final TCD**	**Residual Ranking**
Resources	300T Gantry Crane Required by Another Project/Maintenance Activity	Accept	Medium
Technical	Headcover Seal	Accept	Medium
Project Management	Bearing Failure/Wipe at Commissioning	Mitigate 72209 - OPG to review unit startup procedure 9/30/2025	Medium

Additional Risk Analysis For Project Level A or B
Risks are registered in the online risk tool ePRM. Monte Carlo Analysis was performed resulting in a recommended cost contingency of [redacted]

Financial Evaluation		For Project Level A, B (with multiple feasible alternatives) or Value-Enhancing			
$K	**Alternative**	**Base Case (No Project)**	**Delay Work**	**Alternative 4**	**Alternative 5**
N/A					
Analysis of Financial Evaluation – Key Assumptions and Key Results:					
Financial Evaluation not required for Sustaining Projects.					

Qualitative Factors For Project Level A or B

In addition to delivering technical and operational improvements, the preferred alternative provides significant qualitative benefits that support the investment decision. Refurbishing the generating units at R.H Saunders GS will not only restore the integrity and long-term reliability of the station, ensuring its continued availability, but will also reinforce the facility's environmental stewardship by reducing the risk of equipment failures (e.g. reduce risk of thrust bearing failures, re-establish rotor-stator air gap) and associated potential environmental incidents. Design enhancements will improve health and safety conditions of workers, while operational upgrades will contribute to more efficient and sustainable energy production. These improvements reinforce OPG's social license to operate by demonstrating a proactive commitment to safety, environmental stewardship, and responsible asset management.

Post Implementation Review (PIR) Plan (refer to OPG-GUID-00120-0007)

Is PIR Required?	Yes	**PIR Completion Date**	2028-08-31

PIR KPI's	Current Baseline	Target Result	How to Measure?	Who will measure?
Reduce Oil Leak at Thrust Bearing	Significant Leaks	Reduce of 70%	Monitor leaks after G12 is back in service (Visual Inspection)	Saunders Production
Achieve Required Stator-Rotor Air Gap	~10.99mm	13mm	Through proximity sensor installed in the unit	Saunders Production & Engineering

Definitions and Acronyms

GS	Generating Station
MW	Mega Watts
OM&A	Operation, Maintenance and Administration
AAR	Alkali-aggregate Reaction
IPB	Isolated Phase Bus
CT	Current Transformer
ePRM	Enterprise Project Risk Management Tool
FME	Foreign Material Exclusion

ONTARIO POWER GENERATION

Records File Information:
Retention Permanent

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OPG-FORM-0076-R006*

Business Case Summary

APPENDICES

Appendix A1: Summary of Estimate

Project Number	86587 - SAU - G12 CAPITAL REFURBISHMENT						**FAC**	17553 - CAPITAL - GENERATING FACILITIES		
$K	**LT YE last year**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Future**	**Total**	**%**
0 - Cost Management										0
1 - Project Management	4,273	3,209							7,482	16
2 - Inspection	[redacted]									
3 - Engineering	[redacted]									
4 - Procurement	[redacted]									
5 - Construction	[redacted]									
6 - Commissioning	[redacted]									
Closeout	[redacted]									
Subtotal	[redacted]									
Outside WBS	[redacted]									
Contingency	[redacted]									
Subtotal w/ Contingency	[redacted]									
Interest	[redacted]									
Other	[redacted]									
Total	27,622	19,107	61						46,790	100
Removal Costs (incl. above)	2,440								2,440	5

Project Number	86593 - SAU - G12 OVERHAUL						**FAC**	62030 - OM&A - PROJECT		
$K	**LT YE last year**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Future**	**Total**	**%**
0 - Cost Management										0
1 - Project Management	242								242	2
2 - Inspection	[redacted]									
3 - Engineering	[redacted]									
4 - Procurement	[redacted]									
5 - Construction	[redacted]									
6 - Commissioning	[redacted]									
Closeout	[redacted]									
Subtotal	[redacted]									
Outside WBS	[redacted]									
Contingency	[redacted]									
Subtotal w/ Contingency	[redacted]									

ONTARIO POWER GENERATION

Records File Information:
Retention Permanent

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Business Case Summary

Interest	[redacted]									
Other										
Total	9,435	756							10,191	100
Removal Costs (incl. above)										0

Appendix A2: Summary of Estimate – Notes			
Escalation Rate	**2.50**	**Interest Rate (going-forward)**	**4.25**

Appendix A3: Summary of Estimate - In-Service Estimates

$K — Only applicable to capital projects. In-Service amount shall include interest but exclude removal costs.

Project#	Date	Description	Amount	%
86587	2026-08-28	Unit Available For Service	34,500	88.0
86587	2027-08-27	Project Closeout	4,529	12.0
		Total:	**39,029**	**100**

Prepared by		**Reviewed and Endorsed by (Execution Authority)**	
Morakinyo Apampa Senior Project Leader Southeast Projects 1	2026-05-22	Amanda Griener Project Director Refurbishment Programs	2026-05-25

Appendix B: Total Project Estimate Variance Analysis$K **(Only required when more than one Execution Phase BCS)**

Phase Gate	LT YE last year	2026	2027	2028	2029	2030	2031	Future	Total
G3	27,583	2,797							30,380
Gate 3 - Superseding	27,622	19,107	61						46,790
G3	10,762	174							10,936
G3 - Superseding	9,435	756							10,191

Total Project Estimate Variance Explanation

The Total Project Cost has increased by $15,665k (38%), including contingency.

The main sources of cost and schedule variance to the forecast to complete from the previous gate are summarized below for the major scope areas in execution since the previous full release:

- Project Management and Engineering ([redacted] of net variance): Net change driven by added project controls/management effort and indirect cost impacts from the extended outage/schedule extension. Additionally, net change also reflect added internal/external engineering support for extended outage and design/discovery-driven changes.

- Procurement ([redacted] of net variance): Net change driven by procurement cost related to construction: modified cable tray design, modified servomotor piping and additionally electrical equipment.

- Construction ([redacted] of net variance): Primary driver of the net increase, reflecting additional construction management and refurbishment/reassembly effort, discovery work changes, and commissioning support needs. OM&A construction reductions partially offset but do not change the overall dominant impact. Additionally, capital procurement increases (material/scope change) due to scope/cost realignments.

- Other ([redacted] of net variance): Additionally, interest costs driven by construction challenges.

- Contingency ([redacted]) on incremental release amount, risk model led.

UNDERTAKING JT1.11

Undertaking

Provide a quantitative reconciliation for the Chenaux Limerick Island Superstructure project from the $11.4 million Gate 2 Definition Phase estimate to the $32.7 million Gate 3 Execution Phase estimate, by major cost category and driver, and identify which scope elements were known or foreseeable at Gate 2 versus identified later, and explain whether the increase was driven primarily by scope additions, estimate class maturity, EPC pricing, access/logistics, market escalation, or contingency.

Response

As noted in Ex. L-D1-Staff-316, the Business Case Summary ("BCS") filed at Ex. D1-1-2, Attachment 1, Tab 19 for Project #84494 Chenaux Limerick Island Superstructure Gate Hoist identifies an increase in the cost estimate between the Gate 2 Definition Phase and the Gate 3 Execution Phase. As described in Ex. D1-1-2, p. 6, this is a natural progression as the project continued to solidify scope, complete detailed design, and refine cost estimates throughout the planning process.

In its Procedural Order No. 5, page 2, issued May 1, 2026, the OEB noted:

> As the Class 4 estimate has been superseded by the Class 3 estimate, and the Class 3 estimate[1] is part of the evidentiary record that remains on the public record, the OEB finds that the Class 4 estimate is not relevant to the OEB's consideration of the issues in this proceeding and consistent with the Practice Direction Part 11.

As such, the Gate 2 cost estimate referenced in Ex. D1-1-2, Attachment 1, Tab 19 is not relevant.

For informational purposes, OPG has provided a summary of the evolution of the project cost estimate as it progressed from Gate 2 to Gate 3 in Chart 1 below.

[1] The Class 3 estimate for Project #84494 can be found at Ex. D1-1-2, Table 1, line 13.

Chart 1 – Summary of Cost Variance per BCS Release ($M)

Cost Category	Definition BCS	Execution BCS	Variance	Main Driver
Class of Estimate	5	3	n/a	n/a
Project Management	0.3	0.4	0.1	Estimate Class Maturity
Inspection	[redacted]	[redacted]	[redacted]	Scope Addition
Engineering	[redacted]	[redacted]	[redacted]	Estimate Class Maturity
Construction	[redacted]	[redacted]	[redacted]	Scope Addition/EPC pricing including logistics/access
Subtotal	[redacted]	[redacted]	[redacted]	n/a
Contingency	[redacted]	[redacted]	[redacted]	Estimate Class Maturity
Subtotal w/ Contingency	[redacted]	[redacted]	[redacted]	n/a
Interest	[redacted]	[redacted]	[redacted]	
Total	**11.5**	**32.7**	**21.2**	n/a

Note: Numbers may not add due to rounding.

UNDERTAKING JT1.12

Undertaking

Provide an availability table similar to what is provided in Exhibit F1-1-1 that reflects the actual production forecast for 2027 for the top five stations by production.

Response

Chart 1 below provides, on a best-efforts basis, the calculated availability associated with the 2027 production forecast for the top five regulated hydroelectric stations by production.

As described in Ex. E1-1-1 and Ex. L-E1-Staff-137, and as further discussed at Tr. Tech. Conf., May 27, 2026, pp. 86-87, OPG's production forecast incorporates planned outages and a reduction for forced outage spill events. Therefore, in contrast to Ex. F1-1-1, Chart 7, which includes all planned outage, forced outage and derate hours, the calculated availability in Chart 1 reflects only the planned outage hours and an equivalent number of hours attributable to forced outage spill in the forecast. Accordingly, while Chart 1 is similar to Ex. F1-1-1, Chart 7, it is not a like-for-like comparison.

Chart 1 – Estimated Availability Calculation Based on Production Forecast (%, Top 5 Production Stations in 2027)

Station	2027 Plan
Abitibi Canyon GS	91.6%
Des Joachims GS	84.8%
R.H. Saunders GS	89.0%
Sir Adam Beck 1 GS	85.8%
Sir Adam Beck 2 GS	85.5%

UNDERTAKING JT1.13

Undertaking

Quantify the benefit to the production forecast of the capacity increase at Otter Rapids in 2027.

Response

The forecast capacity increases expected at Otter Rapids GS by 2027 (G2 in service in 2025 and G1 in service in 2026) account for approximately 32 GWh in OPG's 2027 production forecast for the regulated hydroelectric facilities. As described in Ex. L-E1-Staff-136, the forecast capacity increases are realized as production based on forecast water availability and impact of outages.

UNDERTAKING JT1.14

Undertaking

Provide explanation of how OPG expects hydroelectric FTE levels to catch up to the budgeted 2026 and planned 2027 levels, including current hydroelectric OM&A and Capital FTE levels.

Response

As discussed at Tr. Tech. Conf. May 27, 2026, pp. 106-109, OPG understands this undertaking is to provide an explanation of how it expects regulated hydroelectric Full-Time Equivalent ("FTE") levels to meet the 2027 plan. Based on current staffing levels, as well as ongoing and planned recruitment, OPG expects to achieve the 2027 plan of 1,521.5 FTEs for the regulated hydroelectric facilities.

Since the 2025 year-end, OPG has increased the regulated hydroelectric FTEs by 61.6 to 1,391.5 as of April 30, 2026, as a result of sustained hiring efforts that are continuing throughout the year. As of May 2026, OPG had more than 100 positions posted internally and/or externally to continue to meet hiring needs of the Renewable Generating business unit ("RG"). With headcount anticipated to be substantially on plan by year-end 2026, resources are expected to be in place for the start of 2027 to meet the planned FTE demand over the IR term.

To further support recruitment and resourcing, RG has initiated a trainee program, hiring 22 trainees across the fleet in 2025 and is anticipating hiring a similar number of trainees in 2027. In addition, RG is increasing local external hiring in key regions to improve retention and reduce turnover, and is also strengthening the talent pipeline through targeted outreach activities (e.g., trades promotion initiatives, Women in Trades events, and local college and university job fairs) to ensure that the required resources are available to deliver on the plan through 2031.

While Regular staff hiring continues through 2026, priority workload demands are being met through a combination of other resources such as Augmented Staff and purchased services, as well as overtime, where required.

UNDERTAKING JT1.15

Undertaking

Advise how OPG determined whether they needed to hire 173.3 FTEs as OM&A and 188.4 FTEs as capital over the last few years.

Response

When considering the increase in the FTEs, it is important to recognize that OPG's 54 regulated hydroelectric stations operate under distinct local conditions and applicable collective agreement provisions. Thus, many of the resources necessary to support the fleet-wide needs identified below are dispersed at stations and work centres throughout the province. Staffing complements are established, and positions are filled, to meet operational needs within each station's assigned jurisdiction. In many cases, there is limited flexibility to share specialized resources between distant locations without affecting productivity, responsiveness, and outage/work-window execution. This directly influences the overall number of Regular staff required to deliver on OPG's business plan with respect to the hydroelectric facilities.

Determination of the OM&A FTE requirement (+173.3)

Backlog and asset-condition "gap to target" assessment

OPG determined OM&A resourcing needs for the regulated hydroelectric facilities by evaluating the volume and type of corrective and preventive maintenance work, inspection/assessment findings, and the capacity required to monitor, plan, execute, and close work at a pace consistent with reliability and condition-based needs of the hydroelectric station(s). This primarily included Engineering staff to complete plant health assessments and perform condition monitoring, and Maintenance staff to address the work order backlog, while continuing to address emergent work.

The increase in OM&A FTEs is also responsive to the 2022 Value for Money report of the Auditor General of Ontario (as described at Ex. F1-1-1, p. 4), specifically recommendations 4-7, which emphasize improved maintenance management, station-condition assessment, execution of engineering recommendations, and reliability maximization. The OM&A staffing increase supports a sustained, programmatic approach to closing these gaps rather than a short-term, episodic approach to resourcing.

Regulatory compliance resourcing

A further OM&A FTEs driver is the strengthening of compliance capability to sustain performance under the Ontario Reliability Compliance Program ("ORCP"), which is administered by the IESO, and encompasses compliance with:

- North American Electric Reliability Corporation ("NERC") Reliability Standards, including Operations & Planning ("O&P") standards, and Critical Infrastructure Protection ("CIP") standards
- Northeast Power Coordinating Council ("NPCC") Criteria and Directories.

In addition, OPG considered the increased complexity and enforcement posture associated with IESO Market Assessment and Compliance Division ("MACD") and evolving compliance expectations. While certain reliability requirements existed previously, OPG's compliance environment has become more formalized and regulatory in nature, requiring dedicated, trained resources and management systems to remain compliant and audit ready.

Additional resources were also identified as being required to support core regulatory objectives (Environment, Safety, Dam Safety, Public Safety, and broader regulatory requirements), as further described in Ex. F1-1-1, Section 3.2.3.2.

Determination of Capital FTE requirement (+188.6)

The increase in regulated hydroelectric capital FTEs reflects the need to manage the increased capital program volume and complexity, including the turbine-generator refurbishment program, and to ensure adequate capability for:

- Project planning and controls
- Engineering and technical oversight
- Contract/vendor management and integration with station operations
- Supporting schedule performance and deliverability across a multi-year portfolio.

Resourcing of these needs with Regular FTEs is appropriate due to the long-term nature of the refurbishment program and the capital project portfolio, and will help ensure continuity of knowledge, repeatable execution and reduced ramp-up/ramp-down efficiencies across the projects. Among others, this is expected to enable efficiency gains incorporated in later-unit refurbishments.

The capital FTEs increase is also responsive to the 2022 Value for Money report of the Auditor General of Ontario (as described in Ex. F1-1-1, p. 4), specifically recommendations 8 and 9, which focus on improving capital project planning, cost-effective delivery, and timely application of lessons learned to ongoing and future projects – strengthening of which requires increased dedicated project management capacity.

UNDERTAKING JT1.16

Undertaking

Provide examples of projects that are identified as eligible for capacity refurbishment variance account treatment where there are components of the project that are not eligible for variance account treatment, and if there are none in the proposed term, provide any example from the past.;

Response

As OPG discusses in Ex. H1-1-1, Section 5.6, Ex. L-D1-Staff-061 and Ex. L-D1-Staff-081, eligibility for Capacity Refurbishment Variance Account ("CRVA") treatment for OPG's regulated hydroelectric and nuclear facilities is established by O. Reg. 53/05 Section 6(2)4. Ex. L-D1-Staff-061 and Ex. L-D2-Staff-081 outline certain considerations made by OPG in applying these requirements to its projects. The request for this undertaking was based on an exchange at the Technical Conference during which, consistent with the above interrogatory responses, OPG's Ms. Hannon stated that the eligibility for CRVA treatment is determined based on the underlying scope of the projects and further explained that it would be only in unusual circumstances that OPG would conclude that an element of a particular project, rather than the project as a whole, should qualify for the CRVA treatment (Tr. Tech. Conf. May 27, 2026, p. 51, lines 7-17). OPG's witnesses also confirmed that while the specific activities underlying a CRVA eligible project can comprise multiple discrete components, they collectively represent the integrated scope of work necessary to achieve the overall project outcome, such as to refurbish a generating station or to increase a station's generating capacity, and it is this outcome that makes the project eligible under O. Reg. 53/05, Section 6(2)4 (Tr. Tech. Conf. May 27, 2026, pp. 115-120; June 2, 2026, p. 25, line 24 to p. 26, line 24).

OPG is not aware of any projects identified during the 2027-2031 IR term, or in a prior IR term, that contain both components that are considered eligible for CRVA treatment and those that are considered ineligible for such treatment.

UNDERTAKING JT1.17

Undertaking

Provide a representative sample of the health condition report in regards to SEC-41 as well as the plant-level health reports that exist for all of those projects.

Response

Further to the information provided in Ex. L-D1-SEC-041 and the testimony referenced at Tr. Tech Conf., May 27, 2026, pp. 122-125, in this response OPG provides additional context as to both the historical and current health monitoring processes used to assess the condition of the regulated hydroelectric assets.

Prior to 2022, OPG primarily assessed the condition of its assets through Plant Condition Assessments ("PCAs"): periodic analyses of the physical condition of hydroelectric facilities, equipment, and physical processes, including recommendations for potential investments to address identified conditions. Due to the time required to complete a PCA and the number of stations in OPG's hydroelectric fleet, PCAs were completed periodically[1] on a risk-informed basis, taking into consideration factors such as, but not limited to, the date of the last PCA, stations with increased risk as identified through the annual Engineering Risk Assessment Program, and the list of projects scheduled for completion. The last PCA was completed in 2023.

Beginning in 2022, OPG's Renewable Generation business unit ("RG") began implementing an asset condition monitoring process using equipment monitoring software. This approach leverages digital and online tools to provide a more current and standardized snapshot of equipment health (as described in Ex. L-D1-SEC-041, Attachment 1). A summary of the tool output for the major project scope areas is provided in Ex. L-D1-SEC-041, Attachment 3. The process also includes the implementation of cross-functional Plant Health Committee forums, which provide a cross-sectional view of equipment health and risk for a station. This process allows for improved equipment health by focusing on proactive identification and prioritization of plant health risks with oversight from multiple workgroups. Representative samples of Plant Health Committee reports are provided in Attachment 1 (confidential) and Attachment 2 (confidential).

The applicable documentation supporting the need and/or scope for each project listed in Ex. L-D1-SEC-041 is summarized in Chart 1. As the projects span a timeframe of over 10 years, the assessment provided may be a summary of a PCA for older projects (see below), a specific equipment test, or a report that assessed asset condition prior

[1] As noted in Ex. JT1.18, PCAs were completed for all 54 regulated hydroelectric stations.

to the start of the project. These documents identified the need for the investment, however the final scope of work would be determined through the process as outlined in Exhibit D2-1-1, Section 3.0.

Specific to PCAs, as referenced in Ex. L-D1-Staff-309, these assessments were conducted at the plant level for all major components and were not specific to any project. For these assessments, OPG has provided summaries of the condition of the major assets in scope of such projects, as per the applicable PCA. Due to the limited timeframe for preparing the undertaking response, OPG utilized a generative artificial intelligence (AI) tool to prepare these condition summaries. OPG confirms that the summaries were verified by its engineers without the use of the generative AI tool.

In its Procedural Order No. 5, issued May 1, 2026, the OEB noted:

> As the Class 4 estimate has been superseded by the Class 3 estimate, and the Class 3 estimate is part of the evidentiary record that remains on the public record, the OEB finds that the Class 4 estimate is not relevant to the OEB's consideration of the issues in this proceeding and consistent with the Practice Direction Part 11.

As such, and as noted in Ex. L-D1-Staff-309, any estimated costs in the condition assessment documentation referenced in Chart 1 are not relevant; they are considered high-level engineering estimates at the time of such documentation (i.e., not conducted in accordance with Association of Advancement of Cost Engineering International principles) and should not be used for the basis of comparison to future project estimates or actual project performance. Furthermore, for those projects still in the development or definition phases as identified in Chart 1, further analysis will be conducted as the projects refine scope (Ex. D1-1-2, p. 6).

In responding to this undertaking, OPG has not provided further documentation for the following projects as all amounts associated with these projects were reviewed and approved by the OEB in EB-2023-0336.[2]:

- Project #80543 Sir Adam Beck Pump GS – Reservoir Refurbishment (refer to Ex. D1-1-2, p. 10)
- Project #80649 Sir Adam Beck I GS – G10 Major Overhaul & Upgrade (refer to Ex. D1-1-2, p. 22)
- Project #80851 DeCew Falls 2 Generating Station – G2 Overhaul & Upgrade (refer to Ex. D1-1-2, p. 22)

[2] EB-2023-0336, OEB's Decision and Order (June 13, 2024), Issue 4 at page 14. The referenced evidence related to Issue 4, specifically Ex. L-H-CCC-02, confirmed that OPG sought approval of all regulated hydroelectric projects in-service amounts between January 1, 2016 and December 31, 2021 that gave rise to capital-related additions recorded in the Capacity Refurbishment Variance Account, as set out in EB-2023-0336, Ex. H1-1-1.

- Project #82777 Sir Adam Beck 1 GS – Unit G5 Upgrade (refer to Ex. D1-1-2, pp. 23-24).

OPG has also not provided condition assessments for Project #80581 Ranney Falls GS Expansion Project or Project #84185 Sir Adam Beck GS G1/G2 Replacement as these projects were not initiated to address asset condition, but in order to add generating capacity to the existing generating stations.

Chart 1 – Condition Assessment Documentation

Project	Phase	Relevant Assessment	Reference
82089 Calabogie Generating Station - Redevelopment	Closed	Summary of PCA Condition Assessment of the Forebay Intake Pier Structures Calabogie GS - Dam Safety Periodic Review of Associated Hydraulic Structures	Attachment 3 Attachment 4 Attachment 5
89252 Sir Adam Beck 1 - Canal Isolation Preparedness Phase 1 (SAB1 CIP1)	Definition	Closure Structure - Design Review and Condition Assessment of Concrete Structure and Sectional Isolation Gates	Attachment 6
83155 Abitibi Canyon Generating Station - G2 Capital Upgrades/HG	Closed	Initiation Phase Report	Attachment 7
83194 Frederick House Lake Dam Upgrades	Execution - In-Service	Frederick House Control Dam Condition Assessment	Attachment 8
83495 R.H. Saunders Generating Station - G9 Capital Refurbishment	Execution - In-Service	Pre-Overhaul Condition Assessment (2019-2035 Overhauls)	Attachment 9
84494 Chenaux Generating Station - Limerick Island	Execution - In-Service	Limerick Sluice Hoist Assessment	Attachment 10

Project	Phase	Relevant Assessment	Reference
Superstructure Sluice Gate Hoist			
82543 Otter Rapids Generating Station G2 Capital Upgrade	Execution - In-Service	Initiation Phase Report	Attachment 11
82087 Coniston/Stinson Generating Stations Redevelopment	Execution	Summary of Coniston PCA Summary of Stinson PCA Coniston Generating Station, G1, G2 and G3 Turbine Condition Memo Stinson Generating Station, Unit Condition Memo	Attachment 12 Attachment 13 Attachment 14 Attachment 15
86386 Kakabeka Falls Generating Station Redevelopment	Execution	Kakabeka Falls GS Development Condition Assessment Report	Provided at Ex. L-D1-Staff-309, Attachment 5
87768 Sir Adam Beck 2 Generating Station - G20/G19 Refurbishment	Execution	Pre-Overhaul Condition Assessment (2021-2037 Overhauls)	Attachment 16
86387 Matabitchuan Generating Station Redevelopment	Execution	Summary of PCA	Attachment 17
86587 R.H. Saunders Generating Station - G12 Capital Refurbishment	Execution	Pre-Overhaul Condition Assessment (2019-2035 Overhauls)	Attachment 9
82542 Otter Rapids Generating Station - G1 Capital Upgrade	Execution	Initiation Phase Report	Attachment 18
83148 Abitibi Canyon Generating Station	Development	Summary of PCA	Attachment 19

Project	Phase	Relevant Assessment	Reference
- G1 Capital Upgrades			
89505 Abitibi Canyon Generating Station - Concrete Repair Zone 7	In-Service	Initiation Phase Report	Attachment 20
89354 Otto Holden Generation Station - Refurbish Stop Log Sluice Piers	Definition	OTO82327/OTO-0035: East Powerhouse Wall, Stoplog Sluiceways and Associated Works	Attachment 21
82391 Alexander Generating Station - G1 Capital Refurbishment	Development	Summary of PCA	Attachment 22
83833 Silver Falls Generating Station - Surge Tank Replacement	Planning	Silver Falls GS – Surge Tank Condition Assessment	Attachment 23
86792 Alexander Generating Station - G2 Capital Refurbishment	Definition	Summary of PCA	Attachment 24
86793 Alexander Generating Station - G3 Capital Refurbishment	Development	Summary of PCA	Attachment 25
86860 Manitou Falls Generating Station - G3 Capital Refurbishment	Planning	Summary of PCA Field Visit Report - Manitou G3 Generator Inspection	Attachment 26 Attachment 27
87217 Aguasabon Generating Station - Aguasabon Dam Rehabilitation of Hayes Lake Main Dam	Planning	Hays Lake Dam Detailed Inspection and Condition Assessment	Attachment 28
86364 Sir Adam Beck 1 Generating Station - Station Service Upgrade	Definition	Initiation Phase Report	Attachment 29

Project	Phase	Relevant Assessment	Reference
86372 Sir Adam Beck 1 Generating Station - G6 G8 Refurbishment	Execution	Summary of PCA Sir Adam Beck I GS Life Cycle Plan	Attachment 30 Attachment 31
86570 Sir Adam Beck 1 Generating Station - G4 Refurbishment	Execution	Summary of PCA Sir Adam Beck I GS Life Cycle Plan	Attachment 32 Attachment 31
87356 Sir Adam Beck 2 Generating Station - G18 G17 Refurbishment	Development	Pre-Overhaul Condition Assessment (2021-2037 Overhauls)	Attachment 16
87357 Sir Adam Beck 2 Generating Station - G14 G13 Refurbishment	Development	Pre-Overhaul Condition Assessment (2021-2037 Overhauls)	Attachment 16
86937 SAU - G16 Capital Refurbishment	Execution	Pre-Overhaul Condition Assessment (2019-2035 Overhauls)	Attachment 9
87362 Sir Adam Beck 2 Generating Station - 230kV Conductor Replacement	Development	230kV Lines and Towers Assessment Reports	Attachment 33
82328 Otto Holden Generating Station - Concrete Mitigation	Closed	PCA Summary Laboratory Testing and Petrographic Analysis of Concrete Cores Otto Holden GS	Attachment 34 Attachment 35

UNDERTAKING JT1.18

Undertaking

Provide confirmation of any prior versions of the health monitoring and reporting procedure, and provide an assessment of the status of the PCA completion for all 54 hydroelectric stations today for regulated hydro.

Response

OPG clarifies the undertaking to be in reference to OPG's 54 regulated hydroelectric stations, not all 66 hydroelectric stations (12 of which are unregulated).

OPG confirms that there are no prior versions of the Health Monitoring and Reporting (System Health) document provided at Ex. L-D1-SEC-041, Attachment 1. Prior to the implementation of the equipment health monitoring process described in Ex. L-D1-SEC-041 (and further discussed in Ex. JT1.17), Plant Condition Assessments were completed for all 54 regulated hydroelectric stations.

UNDERTAKING JT1.19

Undertaking

Provide the volume of backlog of work orders within the context of Recommendation 4, Action Item 1.

Response

OPG has reduced its work order backlog for its hydroelectric facilities from 9,530[1] tasks in December 2021 to 6,832 as of May 2026, which represents a 28% reduction in the backlog[2]. This improvement has been achieved while maintenance activity to sustain the assets has increased (as described in Ex. F1-1-1, Section 3.0), as demonstrated by an increase of 37% in the annualized work order tasks completed over the same period, from 31,167 to 42,589. Also over the same period, the proportion of higher-priority work in the backlog declined from 76% to 48%. These results reflect stronger work management practices and improved prioritization implemented by OPG.

In its 2024 follow-up report, the Auditor General assessed Recommendation 4, Action Item 1[3] as fully implemented, stating that "OPG had reviewed and revised its work management procedures to ensure appropriate work prioritization and completion by due dates".

[1] Office of the Auditor General of Ontario, Value-for-Money Audit: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations (2022) ("Value for Money Audit (2022)"), page 21.
[2] Inclusive of both regulated and non-regulated assets as per the Value for Money Audit (2022).
[3] Office of the Auditor General of Ontario, Follow-Up on the 2022 Performance Audit: Ontario Power Generation Management and Maintenance of Hydroelectric Generating Stations (2024), page 7.

UNDERTAKING JT1.20

Undertaking

Rationalize what went into the contingency drawdown amount that is noted in D1-AMPCO-016.

Response

In the course of responding to this undertaking, OPG identified an error in the Change Description referenced in Ex. L-D1-AMPCO-016, Attachment 5. The initial budget was established for 2.0 full-time equivalents ("FTEs"), compared to 3.0 FTEs as noted in Ex L-D1-AMPCO-015, Attachment 5. The initial resource allocation was as follows:

- Project Manager, 1.0 FTE
- Project Engineer, 0.5 FTE (not 1.0 FTE as described in Ex. L-D1-AMPCO, Attachment 5)
- Senior Business Development Officer, 0.5 FTE (not 1.0 FTE as described in Ex. L-D1-AMPCO, Attachment 5).

As a result, this Change Control Form supported an increase of 1.25 FTEs over the initial project management level of 2.0 FTEs. Furthermore, this Change Control Form included provisions to manage a four-month extension to the duration of the project schedule. The cost impacts are summarized in Chart 1 below.

Chart 1 – Change Cost Breakdown

Name	Description	Amount ($k)
Increase of 1.25 FTEs	Increase from 2.0 Project Management FTEs to 3.25 FTEs from Dec 2019 to Mar 2023	837.6
Project schedule extension	Project schedule extended by four months, from Apr 2023 to July 2023	246.1
Total		**1,083.7**

UNDERTAKING JT1.21

Undertaking

Reconcile Chart 1 in E1-SEC-132 and Chart 6 in the evidence E1-2-1.

Response

In order to respond to this undertaking, OPG has made the following updates to Ex. L-E1-SEC-132, Chart 1, below:

- Added lines 11 and 12, previously excluded from Ex. L-E1-SEC-132 to remain consistent with OPG's response to Ex. L-M-SEC-10 from EB-2023-0336;
- Corrected line 1 values for 2026 and 2027; and
- Added a new column "Chart 6 Line No." which indicates the corresponding line in Ex. E1-2-1, Chart 6 to where the values for 2026 and 2027 are reconciled, respectively. Where a Chart 6 line number appears more than once, the sum of all the corresponding Chart 1 values below maps to the values on Chart 6 for 2026 and 2027, respectively.

Updated Ex. L-E1-SEC-132, Chart 1

Line No.	Revenue		2026	2027	Chart 6 Line No.
1	Export Revenue	$M	1.8	1.9	4

	Cost		2026	2027	
2	Ontario Zonal Price	$/MWh	0.08	(3.26)	
3	Import Cost	$M	(10.5)	(114.2)	1
4	Non-OPG Gas Cost	$M	(29.7)	5.5	1
5	OPG Gas Cost	$M	(0.9)	(8.2)	2
6	Wind Cost	$M	2.9	1.7	1
7	Wind SBG Cost	$M	(2.9)	(1.7)	3
8	OPG Hydro SBG Cost	$M	(4.4)	(0.9)	3
9	OPG Hydro Cost	$M	4.1	(2.5)	2
10	Total Customer Cost (excluding HIM)	$M	(51.8)	(153.5)	5
11	Other non-OPG cost (primarily Battery Energy Storage Systems)	$M	(8.5)	(29.5)	1
12	OPG Biomass Cost	$M	(0.3)	(1.8)	2

UNDERTAKING JT1.22

Undertaking

Provide the relevant GDAR for the Strategy and Excellence Plan for renewable generation 2026, 2028.

Response

The RG Excellence Plan is developed to set and communicate a path for achieving the Renewable Generation ("RG") business plan, which aligns with OPG's commitment to striving for operational and project excellence. It focuses on strategic initiatives and improvement plans that address key gaps to excellence while ensuring alignment and integration across Regions by which RG's fleet is operated and maintained. The Excellence Plan covering the 2026-2028 period can be found at Ex. L-F1-SEC-150 and is organized around the People, Plant, and Future focus areas identified in Ex. F1-1-1, Section 3.4.1.

The plan is used to identify and advance improvements that support safety, operational effectiveness, asset performance, and workforce productivity. These improvements contribute to long-term cost-effectiveness of the RG fleet, as demonstrated by OPG's regulated hydroelectric operations ranking in the first quintile for OM&A costs (Ex. F1-1-1, Section 5.3, and Ex. A1-3-2, Attachment 1) relative to a benchmark group of peer utilities (Ex. F1-1-1, Section 5.3, and Ex. A1-3-2, Attachment 1).

The Gap-Driver-Action-Results tool ("GDAR") is used to structure and communicate specific plans to address gaps to excellence and to develop the focus area initiatives to be undertaken each year. The initiatives are based on a management review of operational priorities, business risks, and continuous improvement opportunities. Through this process, the Excellence Plan remains current, focused on the highest-value opportunities, and aligned with RG's business objectives.

GDARs developed for the 2026 focus area initiatives are provided in Attachment 1.

Electrifying life

Renewable Generation

2026 Excellence Action Plans (GDARs)

Focus Areas

	Our People	Our Plant	Our Future
2026 Starts	• Promote simple and clear safety messages that resonate with our workforce and vendor partners • Actively guide and support employees to achieve performance expectations	• Enhance Asset Management processes to drive consistency in asset planning and evaluation • Improve unit-over-unit performance through predictability and reliability in project planning and execution	• Future-proof our workforce through knowledge management and succession planning
2027-2028 Starts	• Champion continuous improvement of work protection performance and culture of corrective actions • Strengthen safe work planning, pre-job briefs, and tailboard best practices • Build up agility to lead change to focus on modernization • Advance trust, respect, and inclusion through RG Culture Plans	• Focus efforts to advance key areas of Equipment Reliability • Align on fleet-wide strategies for governors, bearings, and runners. • Optimize maintenance strategies and work management processes across the fleet to start data-centric decision making • Augment process for generation planning and outage planning	• Modernize work processes; integrating data, transitioning to data-centric operations, and standardizing plant configuration across the fleet • Expand training programs to meet tomorrow's needs

OPG

Our People

Promote simple and clear safety messages that resonate with our workforce and vendor partners

GAP - Safety behaviours and messaging could better resonate with frontline employees and vendors

DRIVER – Safety messaging improvements and shared expectations are required to ensure front-line workers and vendor partners receive, understand, and apply consistent safety behaviours

ACTIONS

1. Deliver Regional Frontline Employee / JHSC Engagement Sessions for clear, actionable frontline insights – perform reviews of sessions to improve in 2027
2. Implement High Visibility PPE, Type 2 Class E Hard Hat, Gloves on Hand Plan for visible and consistent safety practices in alignment with construction industry best practices
3. Pilot Peer-to-Peer coaching and mentoring opportunities in the NE
4. Roll-out Due Diligence Awareness Training to people leaders through MyLeadership Academy by YE

RESULTS

- TRIF – target 1.0 (equates to less than 11 recordable injuries for approximately 2,200,000 exposure hours)
- Complete due diligence training for 200 people leaders in 2026 through MyLeadership Academy

Our People

Actively guide and support employees to achieve performance expectations

GAP – Line leaders demonstrate improved confidence and consistency in developing talent and addressing performance gaps

DRIVER – Leader accountability and expectations are required to be set at a fleet level with consistent support on HR tools/routines

ACTIONS

1. Set expectation for senior people leaders to hold annual Manager-Once-Removed (MoR) meetings with their teams and ensure compliance during mid-year and year-end performance reviews.
2. Host Individual Development Plan (IDP) 101 sessions to increase quality and encourage voluntary development of IDPs
3. Progress performance management of staff in the lower categories of 9-Box, as applicable

RESULTS

- 9-box calibration –target 100% IDP for people leaders
- Full completion of Mid-Year and Year End Reviews

Enhance Asset Management processes to drive consistency in asset planning and evaluation

GAP – Improve application of asset management process across renewable generation regions

DRIVER – Current guidelines and process are maturing, requiring refinement and enhancement to meet the needs of the RG fleet

ACTIONS
1. Refine the Generation Loss Framework through revisions to the Energy Loss Calculator for use in evaluating risks
2. Advance the process of how Engineering identifies long-term needs in Engage
3. Benchmark asset management process with industry peers for continuous learning opportunities
4. Enhance Value Framework guidelines in collaboration with external stakeholders and RG Operations
5. Setup ability for a simplified view of portfolio for optimization

RESULTS
1. Long-term asset investment plans for stations with 5-year average generation >500GWh are transitioned to a common platform
2. Benchmarking report documented with approved continuous improvement plan for 2027-2028.

Our Plant

Improve refurbishment unit-over-unit performance and shorten outage duration

GAP – Further enhance refurbishments portfolio oversight and programmatic approach to improve outage baselines and execution plans

DRIVER – Demonstrate on-going value for money, prudence, and consistency in the regional execution of refurbishments and implementation of the programmatic collaboration agreements.

ACTIONS

1. Define Refurbishment and Programmatic Collaboration Agreement (PCA) KPIs for schedule, cost, and safety & environment
2. Implement a Refurbishment Oversight Committee (ROC) to facilitate program oversight and drive continuous improvement
3. Develop station-specific outage and shift strategies to minimize critical path risks and maximize project outage efficiency prior to execution

RESULTS

- Approved Refurbishment Project KPIs to effectively monitor unit-over-unit performance
- ROC reporting that communicates key issues with clarity and precision

Our Future

Future-proof our workforce through knowledge management and succession planning

GAP – Resource management process is regionally driven and requires a fleet view

DRIVER – Consistent documentation practices and fleet-wide resourcing strategies are required to ensure continuity

ACTIONS
1. Develop an RG 2026 staffing plan that includes both attrition and pre-hiring considerations
2. Assess key knowledge areas to develop pre-hire strategies
3. Ensure groups complete succession planning within MyPower

RESULTS
- MyPower Data – target 70% of Management roles have suitable (Ready-Now (RN) 2 Ready-Short (RS)) succession candidates
- Pre-hire strategies complete for trades and hydro operations trainees

OPG