CCC Interrogatory #063

Interrogatory

Reference:
Exhibit E1, Tab 1, Schedule 1, pp. 6-7

Preamble:

OPG's hydroelectric outages are generally planned to conduct the following:

- Refurbishment, redevelopment, or concrete work
- Preventative maintenance
- Condition-based maintenance
- Inspection and testing

In addition to regularly scheduled maintenance outages, refurbishment and overhaul work is planned at select hydroelectric facilities (details on refurbishment projects are provided in Ex. D1-1-2). These major planned outages are accounted for in the 2027 test year production forecast, including anticipated incremental production increases.

Question(s):

a) Please provide the hydroelectric production forecast for the years 2028 to 2031.

b) For each year from 2016 to 2031, please quantify the hydroelectric production lost or forecast to be lost as a result of planned outages.

c) For each year from 2016 to 2031, please quantify the increase in production capacity achieved or forecast to be achieved by OPG.

d) For each year from 2016 to 2025, please quantify the lost production due to SBG.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

a) Chart 1 below provides the 2028-2031 regulated hydroelectric production by region, as reflected in OPG's 2025-2031 Business Plan.

Chart 1
Regulated Hydroelectric Production by Region (TWh)

Operating Region	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Niagara Region	13.9	13.9	13.8	13.9
Eastern Region	15.0	15.2	15.1	15.1
Western Region	3.8	3.9	4.1	3.9
Total Regulated Hydroelectric	32.7	33.0	33.0	32.9

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

b) Chart 2 below provides the requested information for years 2019-2024 (actual) and 2025-2031 (forecast). OPG did not begin tracking production lost due to planned outages until 2019 and is therefore unable to provide this information for 2016-2018.

Chart 2
Actual (2019-2024) and Forecasted (2025-2031) Forgone Regulated Hydroelectric Production Due to Planned Outages

Year	TWh
2019	0.42
2020	0.41
2021	0.20
2022	0.46
2023	0.73
2024	0.34
2025	0.52
2026	0.35

2027	0.77
2028	0.68
2029	0.45
2030	0.32
2031	0.54

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

c) Chart 3 below details the increase in production capacity achieved for the years 2016-2025, and forecast incremental capacity gains for 2026-2031. Refer to Ex. L-A1-Staff-007, Chart 1 for further details. Note that forecasted incremental increases in station capacity from projects to be placed in service 2027-2031 relate to refurbishment and redevelopment projects included in this Application, which may not directly impact the production forecast.

Chart 3
Actual (2016-2025) and Forecasted (2026-2031) Increase in Regulated Hydroelectric Station Capacity

Year	MW
2016	N/A
2017	9.9
2018	N/A
2019	N/A
2020	0.0
2021	0.0
2022	9.5
2023	116.7
2024	0
2025	9.3
2026	6.0
2027	12.3
2028	21.1
2029	23.2

Year	MW
2030	4.9
2031	0.0

d) Refer to Ex. L-E1-ED-011.

CCC Interrogatory #064

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1, p. 2

Preamble:

OPG is also seeking the approval to eliminate the sharing of HIM revenues above the threshold established in Ex. G1-1-1 as described in Section 5.0. This proposal is supported by a Market Surveillance Panel ("MSP") recommendation and is detailed in OPG's SBGVA Study as an outcome of one of the studied options. The proposed removal of HIM revenue sharing maintains OPG's incentives across all market outcomes to the benefit of ratepayers.

Question(s):

a) Please provide the existing HIM threshold and the proposed new HIM threshold.

b) Please confirm that, to date, OPG has never exceeded the HIM threshold, such that there has never been sharing of HIM revenues above the threshold. If not confirmed, please provide details around periods where OPG exceeded the HIM threshold.

c) Please confirm that 50/50 sharing of HIM revenues above the threshold does not eliminate OPG's incentive to shift production.

d) Please describe any situation since the implementation of the HIM and the related threshold where OPG failed to shift production because of 50/50 sharing of the incentive above the threshold, where it would have shifted production had there been no sharing of the incentive.

e) Is it OPG's position that there is no obligation on it to manage production in the most economically efficient manner for its customers, regardless of a separate incentive to do so and even if OPG's costs to do so are covered?

Response

a) The current HIM revenue threshold for the Hydroelectric Incentive Mechanism Variance Account is $54.5M and is based on the forecast of HIM revenue reflected in the hydroelectric payment amounts approved in EB-2013-0321. OPG's 2027 HIM forecast is $17.8M; however, as described in Ex. L-E1-Staff-143, OPG is proposing to eliminate the Hydroelectric Incentive Mechanism Variance Account and accordingly eliminate the need to establish a HIM threshold.

b) Confirmed. OPG has never exceeded the current threshold since it was established in EB-2013-0321.

c) Confirmed. While 50/50 sharing of HIM revenues above the threshold does not eliminate OPG's incentive to time shift production, the incentive is diluted as the sharing of revenues represents an additional variable cost in PGS market offers. Eliminating sharing above the threshold maintains the same incentive across all HIM revenue outcomes as described in Ex. E1-2-1, Attachment 1, Section 3.3.3.

d) As confirmed in part b) above, OPG has never exceeded the current HIM threshold. An illustrative calculation of economic price spreads in circumstances where HIM net revenues exceed the threshold is provided in Ex. E1-2-1, Attachment 1, p. 21, Chart 9. This example demonstrates how revenue sharing above the HIM threshold increases the economic price spread required to cycle the PGS and time-shift energy.

e) No, this is not OPG's position. OPG operates its facilities in accordance with applicable legislation, the IESO's Market Rules, and good utility practice. As described in OPG's Surplus Baseload Generation study,[1] the IESO is responsible for the reliable and economically efficient operation of Ontario's power system. OPG's regulated facilities (other than must-run units) are offered into the market at their marginal cost of production and are dispatched by the IESO. Accordingly, system-wide economic efficiency is achieved through market design and centralized dispatch.

As OPG has stated in its past proceedings, absent an incremental incentive, its economically rational operating behaviour would not align with market price signals. Instead, an economically rational operation would result in OPG operating its assets to maximize total energy output, instead of time-shifting water.[2] As a result, OPG would run a flatter production profile as well as reduce starts and stops to limit turbine wear and tear. OPG would also limit PGS use to only meet operational needs as incremental discretionary use would reduce OPG's total energy output.

The HIM was established to address the misalignment with market drivers by incenting OPG to time-shift generation in response to market prices. The incentive has been supported by the IESO who have previously stated that OPG should be effectively incented to time-shift its hydroelectric generation in response to market

[1] EB-2020-0290, Ex. A1-11-1, Attachment 1.
[2] EB-2013-0321, OPG Argument-in-Chief, pp. 59-60.

prices and that a full (100%) incentive, would provide the clearest signal for OPG to respond to price signals and optimize the timing of generation.[3] The HIM has also been supported by the Market Surveillance Panel in some of its reports.[4]

[3] EB-2013-0321, IESO Submission, August 26, 2014, pp. 2-3.
[4] Market Surveillance Panel Monitoring Report 32 dated July 16, 2020, and Market Surveillance Panel Report 36 dated March 2022.

Environmental Defence Interrogatory #010

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1

Question(s):

a) Please provide an excel spreadsheet with the following data for each hour from 2020 to the present:
   i) PGS pump operation (MW);
   ii) PGS generation (MW);
   iii) SBG (i.e. spillage, MW);
   iv) SBG (i.e. spillage, MW) at the subset of hydro facilities that can serve the PGS pump via the transmission system;
   v) For hours where the PGS pump is not running at full capacity despite SBG conditions, a listing of all the reasons why that is not the case.

b) OPG states: "OPG attributes the increase in PGS utilization and the concomitant decline in hours with SBGVA bookings when the PGS is not pumping to the absence of very high flows on the Niagara river and sufficient price spread in the market." Please provide a table of data to illustrate the change in flows and a forecast of the same data over the next five years. Please also provide a qualitative response regarding the expected flows in the coming years.

c) OPG refers to the "value of SBGVA additions in coincident hours when the PGS was not operated in pump mode exclusively to prevent economic loss to OPG." Please provide a table of these values for the last 10 years (actuals) and the next five years (forecast). Please include the annual amounts both as $ and MWh.

d) How much GHG emissions (CO2e) are avoided via operation of the PGS on the assumption that all power generated from the PGS offsets gas generation. Please provide the response as CO2e/MWh of power generated and CO2e/MWh of power used to operate the pump.

e) For each of the last five years, what percent of all hours had no gas generation in Ontario?

f) Please examine a sampling of hours where there were SBGVA additions in coincident hours when the PGS was not operated in pump mode exclusively to prevent economic loss to OPG. Please pick sample of hours as being the first hour in each month (if any) where such conditions existed over the past 2 years of data.

For each hour in the sample, please provide all pricing information and other data relied on to determine that operating the PGS would result in an economic loss to OPG. For each hour, please explain why operating the PGS would have been uneconomic, including the formulas used by OPG to reach that conclusion.

g) Page 18 refers to the “variable cost formulas that guide market offers.” Please provide all variable cost formulas that guide market offers.

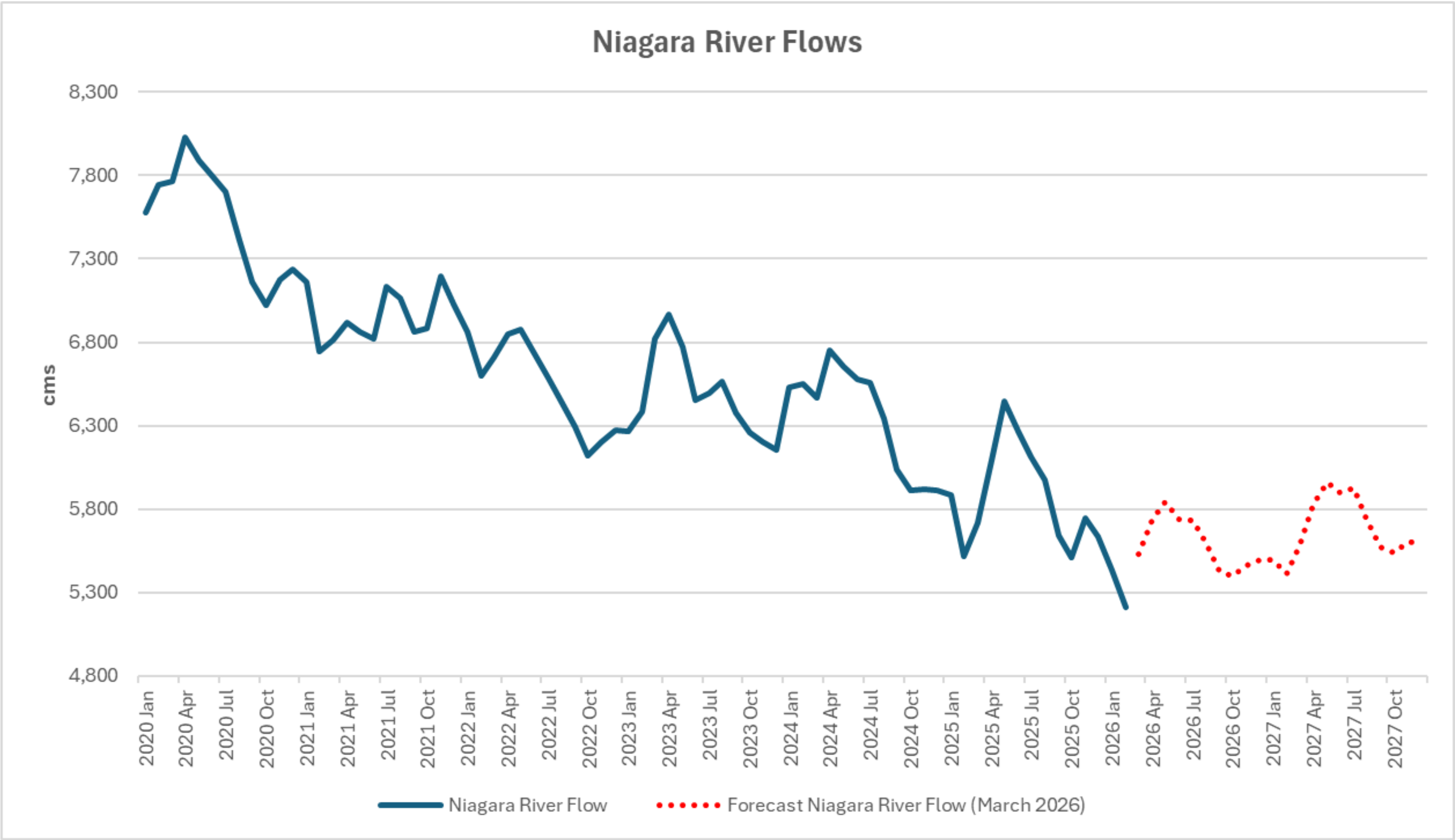
Response

a) Refer to Attachment 1, filed in Microsoft Excel format, for all parts except iv). OPG cannot provide part iv) as OPG does not have the ability to identify a subset of hydroelectric facilities that are uniquely able to power the PGS when in pump mode. The PGS withdraws energy from the IESO-controlled grid when operating in pump mode, and that energy cannot be attributed to any specific resource.

b) Refer to Chart 1 below.

The Niagara River experienced a period of higher-than-average flows from 2017 to 2023. The high flows peaked in 2020 and then began to return to the long-term average. At the time of this response, Niagara River flows are below long-term average. The 2027 test year Niagara River production forecast is based on long-term average flows.

Chart 1
Niagara River Flows – Actual & Forecast (2020-2027)



c) OPG has provided the requested information in Chart 2 for the period 2018-2025, representing eight years of actual data.

Chart 2
SBGVA Additions in Coincident Hours When the PGS Was Not Operated in Pump Mode Exclusively to Prevent Economic Loss

	MWh	$M
2018	260,709	7.4
2019	170,702	4.9
2020	387,900	11.5
2021	374,714	11.2
2022	47,775	1.4
2023	15,427	0.5
2024	14,252	0.4
2025	41,879	1.3
Jan & Feb 2026	4,523	0.2

OPG cannot provide the requested information for 2016 and 2017, as it does not have data of sufficient quality or consistency for those years. OPG has not previously undertaken the complex process required to extract and quantify the requested SBGVA amounts and producing such information would at a minimum require significant data validation, reconstruction and analysis, if it could be completed at all.

OPG does not have the requested information for the next five years. OPG does not have the means of identifying and quantifying instances when PGS is not operating in pump mode exclusively to prevent economic loss to OPG on a forward basis. Such analysis would require inputs that are not available on a forecast basis.

d) The question seeks to quantify greenhouse gas emissions avoided on the assumption that PGS generation offsets gas-fired generation. This involves hypothetical system-level emissions outcomes that depend on broader dispatch, market conditions, and generation mix, which are determined by the IESO. Such analysis is outside the scope of OPG's evidence, and cannot be provided.

e) Refer to Chart 2 below which has been calculated using the publicly available IESO Generator Output and Capability Reports.

Chart 2
Hours With No Gas Generation (2021-2026)

	2021	2022	2023	2024	2025	Jan & Feb 2026
Hours with no gas generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

f) Refer to Ex. H1-1-1, Attachment 3, where OPG has provided a comprehensive list of hours in 2024 where OPG made an addition to the SBGVA but the PGS was not operated in pump mode exclusively to prevent economic loss. For each of these hours, a description of the economic loss that OPG would have incurred is provided along with all associated costs and revenues used in the formulas to make those economic determinations. The formulas that govern PGS economic decision making are provided in Ex. E1-2-1, Attachment 1, p. 10.

OPG has provided this same information for 2025 and January and February 2026 in Attachment 2, filed in Microsoft Excel format.

For more details on economic losses while operating the PGS in pump mode, refer to EB-2023-0336, Ex. H1-1-1, Attachment 3.

g) The variable cost formulas that guide market offers referred to on page 18 of Ex. E1-2-1 are provided in Ex. E1-2-1, Attachment 1, p. 10. They are the breakeven PGS generation price and breakeven PGS pump price formulas.

Environmental Defence Interrogatory #011

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1

Question(s):

a) For the last 10 years (actuals) and the next five years (forecast), please provide the total annual SBG (MWh and $).

Response

a) Refer to Chart 1 below.

Chart 1
Surplus Baseload Generation MWh and $

Year	Foregone Production due to SBG [GWh]	Additions to SBGVA [$M]
2016	4,269	125.6
2017	5,225	147.1
2018	3,224	93.5
2019	3,304	97.8
2020	4,315	130.4
2021	1,882	56.4
2022	1,592	47.9
2023	977	29.9
2024	350	10.6
2025	751	18.4[1]
2026 (forecast)	1,099	26.0[2]

[1] Amount is net of $4.8M in credits to ratepayers at a rate of $600K per month since the Renewed Market went live in May 2025, in accordance with the EB-2023-0336 approved settlement proposal. Pursuant to this settlement, the application of the credits ceases as of the effective date of the regulated hydroelectric payment amount established in this proceeding.

[2] Amount is net of $7.2M in credits to ratepayers at a rate of $600K per month for the same reason as described in footnote 1 above.

The data for 2016-2025 represents the actual regulated hydroelectric forgone production due to surplus baseload generation ("SBG") conditions, and associated dollar amounts recorded in the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA"). The 2026 data is that which underpins the projected account additions provided at Ex. L-H1-Staff-260, Attachment 2, Table 2.

Refer to Ex. E1-2-1, Attachment 1, Figure 1 for an outlook of the 2027-2031 foregone production due to SBG. OPG declines to forecast the additions to SBGVA over the 2027-2031 IR term as these amounts will be recorded in the SBGVA on an actual basis and will be brought forward for disposition in a future proceeding.

Environmental Defence Interrogatory #012

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1

Question(s):

a) Is OPG generally able to predict when SBG condition will arise a number of hours in advance? Please explain.

b) Please describe the efforts made by OPG to avoid SBG by retaining water in the reservoir of hydro stations (aside from run-of-the-river stations).

c) Please provide a table for all OPG hydro facilities with the following:
   i) Name;
   ii) MW capacity; and
   iii) Run-of-the-river vs dispatchable/controllable.

d) How does OPG decide whether to hold water versus generate electricity in its hydro facilities? Please provide all formulas and decision-making criteria.

e) Please provide a table listing for the past five years:
   i) Each hour of SBG where an OPG hydro facility could have been retaining water in a reservoir instead of generating;
   ii) The MW generated by said facilities in said hours, which were not necessary to generate (i.e. could have been avoided by retaining water in the reservoir); and
   iii) The economic rationale for genattacatterating by choice despite SBG conditions.

f) Please provide a table listing for the past five years:
   i) The five hours prior to each SBG event (excluding hours prior to SGB hours that are also SBG hours);
   ii) For each hour, the degree to which (in MW), across OPG's hydro fleet, additional generation could have taken place, such that additional throttling of hydro generation could have occurred during the subsequent SBG hour by retaining water in the reservoir.

Response

a) OPG can generally rely on information from IESO published reports as an indicator of possible SBG conditions. IESO's Surplus Baseload Generation report and the IESO published day-ahead price and pre-dispatch Local Marginal Prices provide an indicator of surplus baseload generation in relation to demand. OPG also considers its view of market conditions to assess possible SBG conditions.

b) As described in OPG's EB 2020-0290 SBG Study and EB 2020-0290, Ex. JT2.25, all hydroelectric energy that is not "must-run" and has no remaining forebay storage opportunity is priced at the Gross Revenue Charge ("GRC") subject to any applicable operational and Safety, Equipment and Applicable Laws (SEAL) considerations. Energy associated with available storage is offered at a value higher than GRC based on the applicable forebay storage horizon. Accordingly, if the market price reflects SBG conditions, a resource with available storage will not be economic and will not be scheduled to generate thereby causing the water to be stored. Once the resource is offered at GRC to reflect that the storage has been exhausted, the resource will spill until the price no longer reflects the presence of SBG conditions. OPG's effort to reflect the status of its hydroelectric energy in relation to available storage helps to avoid SBG by retaining water in the reservoir of hydro stations.

c) Refer to Ex. L-A1-Staff-285 c).

d) As described in its SBG Study[1], OPG makes decisions regarding the operation and management of hydroelectric energy at its facilities over different time horizons. While OPG's longer-term water management focuses on operational, environmental, and safety constraints, the impact of SBG conditions is also addressed through OPG's objective to maximize generation and minimize spill. OPG factors in market signals by withdrawing from storage during days or hours of expected stronger market prices. From a seasonal perspective, the increased forebay room following winter drawdown, has a favourable effect on minimizing SBG spill, which is typically more prevalent during higher spring flows.

In the short-term horizon, OPG does not directly decide when to hold water versus generate electricity. Instead OPG offers all available hydroelectric energy in all hours of the day and then follows dispatch instructions received from the IESO based on those offers.

As described in part b) OPG's short-term decision on how to offer its hydroelectric facilities considers must-run conditions, ability to spill, availability of storage and the opportunity cost associated with a storage horizon. OPG's decision making criteria

[1] EB-2023-0336, Ex. M1-1-1, Attachment 1, pp. 17-22

to associate hydroelectric energy with a certain offer state is based on forebay elevations, inflow conditions, unit availability and are subject to SEAL and operational constraints. With the exception of Sir Adam Beck Pump Generating Station (the formulas for which are provided in Ex. E1-2-1, Attachment 1, page 10), once a quantity of hydroelectric energy is associated with an energy state, OPG generally applies offer pricing methodologies rather than formulas as follows:

- Must-run: Offered at a negative price
- GRC: Offered at the average GRC for the station
- Storable Base/Flex Pricing: Based on OPG's view of the highest price over the applicable storage horizon (i.e., highest price in current day, or over course of next days/weeks).

e) OPG is unable to provide information pertaining to SBG hours where an OPG hydroelectric facility could have been retaining water in a reservoir instead of generating. While SBG hours are isolated for the purposes of booking amounts in the Hydroelectric Surplus Baseload Generation Variance Account, the identification of available storage at OPG's hydroelectric resources is dependent on OPG's after-the-fact knowledge of all the operational and SEAL constraints in effect for that hour that impacted OPG's ability to deviate from the actual forebay elevations reached in that hour. Such information is included in OPG's actual offers to the market and is not catalogued in a format allowing for hourly, after-the-fact re-evaluation. Further, as described in part b) above, OPG's effort to reflect the status of its hydroelectric energy in relation to available storage through its offers at the market maximizes storage in advance of SBG related spill. Specifically, MWs "which were not necessary to generate" would be priced in a manner in which they would not be economically dispatched by the IESO under SBG conditions and thus would be stored rather than generated.

f) OPG is unable to provide the requested information as this type of assessment would require detailed insight into the operational characteristics, offers, and constraints of all market participants, as well as the re-execution of the system dispatch optimization performed by the IESO. OPG does not have access to the full set of inputs required to perform such an analysis, nor does it have the capability to replicate the IESO's dispatch algorithms.

Environmental Defence Interrogatory #013

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1

Question(s):

a) During SGB hours, generally what price does OPG offer to sell electricity at in export markets? If the number varies, please provide a table showing:
   i) All SBG hours over the past five years;
   ii) The price at which OPG offered to sell electricity at in neighbouring jurisdictions.

b) Please explain how OPG determined its bid/offers for hydro electricity during SGB hours.

Response

a) OPG's regulated business does not offer to sell electricity into export markets. Two of OPG's regulated generating facilities – R.H. Saunders GS and Chats Falls GS, may engage in Segregated Mode of Operation (SMO) transactions through bilateral agreements with Hydro-Quebec.[1] Coincident with SBG conditions, OPG typically offers SMO[2] at the applicable Ontario price (i.e., HOEP in the Legacy Market and LMP in the Renewed Market) plus an $7/MWh-$10/MWh adder representing export costs from the Ontario Market, including the Export Transmission Service, IESO Usage Fees and SMO related line losses.

b) OPG's offer strategy for its regulated hydroelectric facilities, including when coincident with SBG conditions, is described in Ex. L-E1-ED-012, part b). As stated in OPG's response to Ex. L-E1-ED-010, part g), OPG's offer strategy for its Sir Adam Beck Pump Generating Station (PGS) is based on the variable cost formulas provided in Ex. E1-2-1, Attachment 1, p. 10.

[1] Occasionally OPG may use SMO to flow through Quebec and into neighbouring markets or sell energy to other counterparties.
[2] Some SMO transactions take place over a pre-defined period (i.e., over several days or weeks) and may overlap with the presence of SBG conditions.

Environmental Defence Interrogatory #014

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1, Attachment 1

Question(s):

a) Please discuss the design of a DVA that would (i) ensure that OPG runs the PGS to avoid SBG in each hour where it is economic to do so from the perspective of all Ontario ratepayers as a whole (ii) make OPG whole for any hours where operating the PGS would otherwise result in an economic loss for OPG. For example, the DVA could allow OPG to earn sufficient revenue for each relevant hour to encourage it to run the PGS where Ontario ratepayers would benefit. Please provide the calculation for such a DVA.

Response

a) OPG does not have the information or tools required to design and calculate a DVA of the type described.

With respect to part (i), OPG cannot perform next-day or intra-day operational calculations from the perspective of "all Ontario Ratepayers as a whole". OPG's operational decisions are made based on information available to it as a market participant. While OPG considers ratepayer benefit as part of its Total Customer Cost calculations as part of its long-term forecast modelling and scenario analysis, OPG does not have access to the information (e.g., joint optimization, enhanced real-time unit commitment, and the like) to determine, on an hourly basis, whether operation of the PGS would be economic from the perspective of all Ontario ratepayers.

Additionally, OPG notes that this question assumes the only barrier for PGS utilization is economic. As identified in OPG's annual SBG reporting, there are other reasons that prohibit PGS utilization (e.g. SEAL, crossover levels, etc.).

With respect to part (ii), a DVA that makes OPG whole whenever PGS operation would otherwise be uneconomic would change the market behaviour of the PGS relative to other storage resources that respond to price differentials. While such a DVA could address OPG losses associated with uneconomic operation of the PGS, such operation may not benefit Ontario ratepayers due to the losses associated with the PGS cycling efficiency. Absent a sufficient price spread differential to support PGS cycling, the overall system cost may go up in the form of higher DVA amounts than any savings attributed to cycling.

Environmental Defence Interrogatory #015

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1, Attachment 1

Question(s):

a) In lieu of removing the GRC payments for PGS operation, please discuss the pros, cons, and viability of a DVA that would allow OPG to recoup via rates the amount of GRC payments for PGS operations for SBG hours.

b) In lieu of an exemption for PGS variable load charges, please discuss the pros, cons, and viability of a DVA that would allow OPG to recoup via rates the amount of said charges for PGS operations for SBG hours.

c) Please estimate the incremental benefit of removing the Beck GRC charges, which are shown on page 9. Please reproduce chart 7 with an additional row showing the incremental benefit.

Response

a) OPG does not identify a ratepayer benefit to a deferral and variance account ("DVA") that would defer recovery of Gross Revenue Charge ("GRC") payments associated with PGS operations in SBG hours for later recovery through rates. The GRC forms part of OPG's PGS breakeven equations because it is a cost incurred and borne by ratepayers through OPG's regulated hydroelectric revenue requirement. OPG does not identify a benefit of a DVA construct that defers the recovery of these costs in the future as they will continue to reflect an incremental cost of cycling the PGS. Cycling the PGS provides a benefit to the ratepayer only when the Total Customer Cost savings as a result of shifting energy from off peak to on peak exceeds the costs incurred, regardless of when they are recovered from the ratepayer. This is accomplished by the Hydroelectric Incentive Mechanism, which aligns the utilization of the PGS with market price signals. With respect to viability, the establishment of any DVA would need to satisfy the OEB's applicable criteria for a deferral and variance account.

b) As explained in part a), appropriate accounting for costs borne by the ratepayer is essential for realizing comprehensive Total Customer Cost reduction when making PGS operational decisions. As discussed in OPG's SBGVA study, OPG is in the process of implementing changes to eliminate variable load charges. A DVA that,

c) instead of removing these charges, defers their recovery does not lead to ratepayer benefit if these costs are higher than the savings from shifting energy from off peak to on peak based on a price spread. With respect to viability, the establishment of any DVA would need to satisfy the OEB's applicable criteria for a deferral and variance account.

d) The removal of Beck GRC from both the breakeven PGS generation price and the breakeven PGS pump price would not create any meaningful incremental benefit. The Beck GRC is factored twice in the numerator of both PGS pricing formulas, each time multiplied by the Beck Efficiency factor. As the Beck Efficiency factors are almost identical in pump and gen modes, the two terms cancel, thereby making the impact of removing Beck GRC insignificant for both the breakeven PGS generation price and the breakeven PGS pump price. Accordingly, further analysis is not expected to change the results in Ex. E1-2-1, Attachment 1, Chart 7.

Environmental Defence Interrogatory #016

Interrogatory

Reference:
Exhibit E1, Tab 2, Schedule 1, Attachment 1
Exhibit E2

Question(s):

a) Please provide a table showing, for each year in the rate term:
   i) The hydro production forecast (MWh); and
   ii) The hydro production forecast (MWh) if the GRC did not exist (or if the GRC were disregarded in generation decision-making).

b) Please comment on how elimination of the GRC would impact the quantity of hydro generation in Ontario and why. Note, this question is exploring the impact of the GRC and the OPG production forecast. It is not suggesting that the GRC is slated to be eliminated.

c) Please discuss the viability of OPG's payment amounts being based on both energy ($/MWh) and capacity ($/MW) to encourage optimal decisions to generate at peak versus non-peak times.

Response

a)
   i) For 2027 information, refer to Ex. E-1-1-1, Table 2. Regarding 2028-2031 information, refer to Ex. L-A1-SEC-011, part a).

   ii) Apart from the Sir Adam Beck Pump Generating Station (PGS), OPG's hydroelectric production forecasting does not consider GRC as an input. While GRC is a consideration in OPG's offer strategies in the day-ahead and real-time markets, longer-term forecasting is on a pre-SBG basis and assumes that the water available will be generated, considering variables such as flow forecasts, unit availability, target forebay elevations and storage horizons. Changes in PGS net output with the elimination of GRC would decrease overall Sir Adam Beck GS output, albeit minimally given the relative size and output of the PGS.

b) Refer to part a) ii). The quantity of hydroelectric power available in the province is not affected by GRC.

c) Section 78.1 of the *Ontario Energy Board Act, 1998* specifies that OPG is to be compensated with respect to the output generated at its regulated facilities. In that context, it is not possible to establish a payment amount structure by which OPG is compensated for capacity ($/MW) instead of energy ($/MWh).

Obligations to provide capacity to the market are addressed through OPG's Electricity Generation Licence (EG-2023-0231). Part 8 of the Licence requires that OPG, at all times during any period that the Renewed Market Rules (as defined in the Market Rules) are in force, offers all available generating capacity into the IESO administered markets for Energy and Operating Reserve, including the Day-Ahead Market and the Real-Time Market.

The Hydroelectric Incentive Mechanism ("HIM") remains the primary mechanism that provides OPG an economic incentive to shift generation to peak-periods. As discussed in Ex. E1-2-1, the HIM mechanism results in benefits for both OPG and ratepayers.

IESO Interrogatory #001

Interrogatory

Reference:
Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / Pages 4-9

Preamble:

While both global Surplus Baseload Generation (SBG) and local SBG can lead to hydroelectric spill, this section explains why global SBG conditions were used to quantify SBG spill when calculating Surplus Baseload Generation Variance Account (SBGVA) entries in the Legacy Market and why global SBG conditions can no longer be differentiated from local SBG conditions in the Renewed Market. This section details OPG's proposal to continue to quantify SBG spill and make entries to the SBGVA on a total SBG basis (i.e., include spill due to global and local SBG conditions).

Question(s):

1. The proposed SBGVA recovery mechanism would compensate OPG for spill arising from local surplus conditions at a regulated rate, offsetting financial incentives that may otherwise encourage OPG to respond to local congestion through its production decisions. In this context, please:

    a) Describe how the proposed SBGVA recovery mechanism provides value to the system through improved market outcomes; and

    b) Provide all analysis OPG conducted or received relating to how the proposed SBGVA recovery mechanism will affect or has affected the energy and OR markets.

2. Please provide all analysis OPG conducted or received relating to the use of Locational Market Prices as an indicator for SBG conditions.

3. Please update "Chart 2: SBG Spill Booked to SBGVA (MWh)" found at Exhibit E1 Tab 2 Schedule 1 Page 8 as follows:

    a) Provide monthly booked spill amounts from October 2025 through to the most recent month for which data is available.

    b) Sum the total SBG spill booked for each full year (i.e., 2021-2025)

The table below is provided as an example of how OPG may choose to present the requested data.

Chart 2: SBG Spill Booked to SBGVA (MWh)							
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**Avg.**
January	195	51	54	3	5	TBD	TBD
February	118	72	152	15	0	TBD	TBD
March	258	74	85	20	48	TBD	TBD
April	399	276	199	77	131	TBD	TBD
....							
December	62	62	6	17	TBD	TBD	TBD
Annual MWh Total	TBD	TBD	TBD	TBD	TBD	TBD	TBD

4. Please provide a chart, in the same format as the above referenced Chart 2, showing the monthly dollar amounts recorded in the SBGVA account corresponding to each monthly spill amount provided in response to part (c)

   a) Please sum the total dollar amounts for each full year (i.e., 2021-2025)

Response

1)

a) The IESO co-optimizes across energy and the three operating reserve markets using its dispatch scheduling and optimization ("DSO") engine to arrive at the most efficient dispatch for every resource, including interties, in the IESO Administered Market ("IAM"). In accordance with the definitions established in IESO's Renewable Integration Stakeholder Engagement 91 (SE-91), Surplus Baseload Generation ("SBG") conditions can occur on a global or local level[1] with the conclusion that the most efficient market outcome relies on OPG's

[1] IESO, Renewable Integration Stakeholder Engagement 91, Surplus Baseload Generation Definition

flexible hydroelectric energy being dispatched down first[2]. The value to the system is realized through OPG's ability to respond to 5-minute dispatch as SBG conditions may persist for only a short duration. The proposed SBGVA recovery mechanism and the new HIM aligns with the Renewed Market in their use of Locational Marginal Prices as inputs in their respective algorithms and calculations.

b) OPG has not conducted or received analysis relating to how the proposed SBGVA recovery mechanism will affect or has affected the energy and OR markets. As explained in Ex. E1-2-1, the proposed SBGVA mechanism addresses impacts arising from the implementation of the Renewed Markets by identifying SBG conditions based on the Locational Marginal Price. As the changes to the SBGVA recovery mechanism have not had any impact on OPG's offer strategy, there is no basis to evaluate hypothetical impacts on either the energy or the OR market.

2) OPG has provided analysis related to the use of Locational Marginal Prices as an indicator for SBG conditions in EB-2023-0336, Ex. L-M-ED-10b). The analysis demonstrates that in the Renewed Market there is not a parallel indicator of what was previously identified as Global SBG conditions via the Legacy Market's unconstrained run output – the Hourly Ontario Energy Price ("HOEP"). OPG also relied on materials provided by the IESO in its SE-91 Stakeholder Engagement. Specifically, the IESO stated that floor prices would have the effect of establishing Market Clearing Price during times of surplus baseload generation and set the locational price during times of local surplus.[3]

3)

a) and b) Refer to updated Chart 2 in OPG's response to Ex. L-E1-SEC-130.

4) See Chart 1 Below.

[2] IESO, Renewable Integration Stakeholder Engagement 91, Floor Price Working Group, July 29, 2013
[3] IESO, Renewable Integration Stakeholder Engagement 91, Floor Price Focus Group, "Floor Prices Update, SE-91 Integration", August 8, 2012

Chart 1
SBGVA Additions ($M)[4,5]

	2021	2022	2023	2024	2025	2026	Average
January	7.5	1.9	1.6	0.1	0.2	0.1	2.0
February	4.4	2.7	4.6	0.5	0.0	0.3	2.3
March	8.3	1.4	2.5	0.5	1.4		2.7
April	12.4	8.7	6.0	2.5	4.3		6.6
May	8.8	11.6	9.0	1.4	12.8		8.8
June	2.8	8.9	0.9	2.1	1.2		3.2
July	1.9	0.1	0.0	0.2	0.5		0.5
August	1.0	0.9	0.5	0.3	(0.2)		0.5
September	3.8	2.1	0.3	0.5	0.1		1.4
October	2.2	1.8	2.8	0.5	(0.3)		1.4
November	1.4	6.2	1.2	1.5	(0.5)		2.0
December	1.9	1.6	0.2	0.5	(1.0)		0.6
Total	**56.4**	**47.9**	**29.7**	**10.6**	**18.4**		**31.9**

[4] The SBGVA additions after May 2025 as presented in Chart 2 include a monthly $0.6M reduction in accordance with the OEB-approved EB-2023-0336 Settlement Proposal, which is applicable until the effective date of the Payment Amounts Order in this Application.
[5] Numbers may not add due to rounding

IESO Interrogatory #002

Interrogatory

Reference:
Exhibit E1 / Tab 2 / Schedule 1 / Pages 10-20

Preamble:

The Hydroelectric Incentive Mechanism (HIM) is designed to encourage shifting hydroelectric production from lower value to higher value periods in response to market signals.

Question(s):

1. Please describe how the proposed change to SBGVA recovery mechanism would strengthen the incentives to respond to price signals during low price hours to shift energy production instead of spilling the energy and being compensated through the variance account.

2. The market co-optimizes between energy and operating reserve market to efficiently utilize resources required to meet system needs.

   a) How does the HIM incentivize efficient participation in both the energy and operating reserve markets?

   b) How could the HIM be revised to improve the incentive to provide ancillary services like operating reserve in the wholesale market?

   c) Please provide all analysis OPG conducted or received regarding the HIM and participation in the energy and operating reserve markets.

Response

1. OPG's proposed change to the SBGVA recovery mechanism aligns with the new HIM, including the Unintended Benefit, with each algorithm utilizing Locational Marginal Prices as an input. As such, OPG continues to be incentivized by the new HIM to shift generation from low-priced hours (thereby reducing amounts booked in the SBGVA) to high-priced hours in accordance with market signals. Any SBGVA spill resulting from time-shifting is also realized as a negative adjustment via the Unintended Benefit calculation, providing an incentive for OPG to avoid incurring such spill.

2.

a) The Hydroelectric Incentive Mechanism (HIM) was developed in respect to energy output as required by the OEB Act and regulation by the OEB to provide an incentive for OPG to respond to market signals in a manner that benefits consumers by shifting hydroelectric production to high-priced hours. The HIM is not intended to optimize across energy output and ancillary services like operating reserve (OR), where the latter is outside of the OEB regulatory regime. In respect to efficiency, OPG offers its available energy and OR in the IESO Administered Markets (IAM) and “the IESO’s decisions on who will provide the market with Operating Reserve, and who will supply the market with energy, are integrated to arrive at the optimum market outcome.”[1]

b) As described in part a) the HIM was developed in respect to energy output, and in particular shifting hydroelectric production to high-priced hours. The HIM was not designed to act as an incentive for the overall provision of wholesale market products and services, including those related to ancillary services such as Operating Reserve. As such, the HIM is not an appropriate mechanism to be studied or adjusted in the pursuit of hypothetical improvements to the provision of such services.

c) OPG has not undertaken or received analysis regarding the HIM and participation in the energy and operating reserve markets with the exception of the three options explored in OPG’s SBGVA study[2], which evaluate the impact on energy dispatch of certain changes to the inputs and framework underpinning the HIM.

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[1] IESO Monthly Market Report Archive, Operating Reserve Prices Section <https://ieso.ca/en/Power-Data/Monthly-Market-Report-Archive/>
[2] Ex. E1-2-1, Attachment 1

SEC Interrogatory #128

Interrogatory

Reference:
E1-1-1, p. 6

Question(s):

Please provide a list of the current planned outages for hydroelectric stations over 2027-2031, including start date and expected outage length.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

Refer to Attachment 1 for 2027 outage data (confidential) and Attachment 2 for 2028-2031 outage data (confidential), as reflected in the regulated hydroelectric production forecast provided in Ex. E1-1-1 (for 2027) and Ex. L-E1-CCC-063, and OPG's 2025-2031 Business Plan.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

L-E1-SEC-128 - Attachment 1
2027 Regulated Hydroelectric Outage Data

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
ABITIBI CANYON GS	G1	[redacted]	
ABITIBI CANYON GS	G1		
ABITIBI CANYON GS	G2		
ABITIBI CANYON GS	G3		
ABITIBI CANYON GS	G4		
ABITIBI CANYON GS	G4		
ABITIBI CANYON GS	G5		
ABITIBI CANYON GS	G1		
ABITIBI CANYON GS	G2		
ABITIBI CANYON GS	G2		
ABITIBI CANYON GS	G3		
ABITIBI CANYON GS	G3		
ABITIBI CANYON GS	G4		
ABITIBI CANYON GS	G5		
ABITIBI CANYON GS	G5		
ABITIBI CANYON GS	G1		
ABITIBI CANYON GS	G4		
ABITIBI CANYON GS	G1		
ABITIBI CANYON GS	G4		
ABITIBI CANYON GS	G1		
AGUASABON GS	G1		
AGUASABON GS	G2		
AGUASABON GS	G1		
AGUASABON GS	G2		
ALEXANDER GS	G1		
ALEXANDER GS	G2		
ALEXANDER GS	G1		
ALEXANDER GS	G2		
ALEXANDER GS	G3		
ALEXANDER GS	G4		
ALEXANDER GS	G5		
ALEXANDER GS	G1		
ALEXANDER GS	G2		
ALEXANDER GS	G4		
ALEXANDER GS	G5		
ALEXANDER GS	G1		
ALEXANDER GS	G2		
ALEXANDER GS	G3		
ALEXANDER GS	G4		
ALEXANDER GS	G5		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
ALEXANDER GS	G1	[redacted]	
ALEXANDER GS	G2	[redacted]	
ALEXANDER GS	G3	[redacted]	
ALEXANDER GS	G4	[redacted]	
ALEXANDER GS	G5	[redacted]	
ALEXANDER GS	G2	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G2	[redacted]	
ARNPRIOR GS	G1	[redacted]	
ARNPRIOR GS	G2	[redacted]	
BARRETT CHUTE GS	G1	[redacted]	
BARRETT CHUTE GS	G1	[redacted]	
BARRETT CHUTE GS	G2	[redacted]	
BARRETT CHUTE GS	G3	[redacted]	
BARRETT CHUTE GS	G3	[redacted]	
BARRETT CHUTE GS	G4	[redacted]	
BARRETT CHUTE GS	G2	[redacted]	
BARRETT CHUTE GS	G3	[redacted]	
BARRETT CHUTE GS	G4	[redacted]	
BARRETT CHUTE GS	G3	[redacted]	
BARRETT CHUTE GS	G1	[redacted]	
BARRETT CHUTE GS	G2	[redacted]	
BARRETT CHUTE GS	G3	[redacted]	
BARRETT CHUTE GS	G4	[redacted]	
BARRETT CHUTE GS	G1	[redacted]	

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
BARRETT CHUTE GS	G2	[redacted]	[redacted]
BARRETT CHUTE GS	G1	[redacted]	[redacted]
Bingham Chute GS	G1	[redacted]	[redacted]
Bingham Chute GS	G2	[redacted]	[redacted]
Bingham Chute GS	G1	[redacted]	[redacted]
Bingham Chute GS	G2	[redacted]	[redacted]
Calabogie GS	G1	[redacted]	[redacted]
Calabogie GS	G2	[redacted]	[redacted]
Calabogie GS	G1	[redacted]	[redacted]
Calabogie GS	G2	[redacted]	[redacted]
CAMERON FALLS GS	G7	[redacted]	[redacted]
CAMERON FALLS GS	G1	[redacted]	[redacted]
CAMERON FALLS GS	G2	[redacted]	[redacted]
CAMERON FALLS GS	G3	[redacted]	[redacted]
CAMERON FALLS GS	G4	[redacted]	[redacted]
CAMERON FALLS GS	G5	[redacted]	[redacted]
CAMERON FALLS GS	G6	[redacted]	[redacted]
CAMERON FALLS GS	G7	[redacted]	[redacted]
CAMERON FALLS GS	G2	[redacted]	[redacted]
CAMERON FALLS GS	G3	[redacted]	[redacted]
CAMERON FALLS GS	G4	[redacted]	[redacted]
CAMERON FALLS GS	G5	[redacted]	[redacted]
CAMERON FALLS GS	G6	[redacted]	[redacted]
CAMERON FALLS GS	G7	[redacted]	[redacted]
CAMERON FALLS GS	G2	[redacted]	[redacted]
CARIBOU FALLS GS	G1	[redacted]	[redacted]
CARIBOU FALLS GS	G2	[redacted]	[redacted]
CARIBOU FALLS GS	G3	[redacted]	[redacted]
CARIBOU FALLS GS	G2	[redacted]	[redacted]
CARIBOU FALLS GS	G1	[redacted]	[redacted]
CARIBOU FALLS GS	G2	[redacted]	[redacted]
CARIBOU FALLS GS	G3	[redacted]	[redacted]
CHATS FALLS GS	G6	[redacted]	[redacted]
CHATS FALLS GS	G7	[redacted]	[redacted]
CHATS FALLS GS	G2	[redacted]	[redacted]
CHATS FALLS GS	G3	[redacted]	[redacted]
CHATS FALLS GS	G4	[redacted]	[redacted]
CHATS FALLS GS	G5	[redacted]	[redacted]
CHATS FALLS GS	G2	[redacted]	[redacted]
CHATS FALLS GS	G8	[redacted]	[redacted]
CHATS FALLS GS	G3	[redacted]	[redacted]
CHATS FALLS GS	G9	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G1	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G2	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G3	[redacted]	[redacted]
CHENAUX GS	G4	[redacted]	[redacted]
CHENAUX GS	G4	[redacted]	[redacted]
CHENAUX GS	G4	[redacted]	[redacted]

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
CHENAUX GS	G4	[redacted]	
CHENAUX GS	G4		
CHENAUX GS	G4		
CHENAUX GS	G4		
CHENAUX GS	G4		
CHENAUX GS	G4		
CHENAUX GS	G4		
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CHENAUX GS	G4		
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CHENAUX GS	G4		
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CHENAUX GS	G6		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
CHENAUX GS	G6	[redacted]	
CHENAUX GS	G6		
CHENAUX GS	G6		
CHENAUX GS	G6		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G7		
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CHENAUX GS	G7		
CHENAUX GS	G8		
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CHENAUX GS	G8		
CHENAUX GS	G8		
CHENAUX GS	G8		
CHENAUX GS	G1		
CHENAUX GS	G2		
CHENAUX GS	G3		
CHENAUX GS	G4		
CHENAUX GS	G5		
CHENAUX GS	G3		
CHENAUX GS	G1		
CHENAUX GS	G5		
CHENAUX GS	G7		
CHENAUX GS	G7		
CHENAUX GS	G8		
Coniston GS	G1		
Coniston GS	G2		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
Crystal Falls GS	G1	[redacted]	[redacted]
Crystal Falls GS	G2	[redacted]	[redacted]
Crystal Falls GS	G3	[redacted]	[redacted]
Crystal Falls GS	G4	[redacted]	[redacted]
Crystal Falls GS	G4	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS 2 GS	G1	[redacted]	[redacted]
DECEW FALLS 2 GS	G2	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G5	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G6	[redacted]	[redacted]
DECEW FALLS GS	G7	[redacted]	[redacted]

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G5	[redacted]	
DECEW FALLS GS	G5	[redacted]	
DECEW FALLS GS	G5	[redacted]	
DECEW FALLS GS	G6	[redacted]	
DECEW FALLS GS	G6	[redacted]	
DECEW FALLS GS	G6	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G5	[redacted]	
DECEW FALLS GS	G6	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DECEW FALLS GS	G5	[redacted]	
DECEW FALLS GS	G6	[redacted]	
DECEW FALLS GS	G7	[redacted]	
DECEW FALLS GS	G8	[redacted]	
DES JOACHIMS GS	G1	[redacted]	
DES JOACHIMS GS	G1	[redacted]	
DES JOACHIMS GS	G2	[redacted]	
DES JOACHIMS GS	G2	[redacted]	
DES JOACHIMS GS	G3	[redacted]	
DES JOACHIMS GS	G3	[redacted]	
DES JOACHIMS GS	G4	[redacted]	
DES JOACHIMS GS	G4	[redacted]	
DES JOACHIMS GS	G4	[redacted]	
DES JOACHIMS GS	G5	[redacted]	
DES JOACHIMS GS	G5	[redacted]	
DES JOACHIMS GS	G5	[redacted]	
DES JOACHIMS GS	G6	[redacted]	
DES JOACHIMS GS	G6	[redacted]	
DES JOACHIMS GS	G6	[redacted]	
DES JOACHIMS GS	G7	[redacted]	
DES JOACHIMS GS	G7	[redacted]	
DES JOACHIMS GS	G7	[redacted]	

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
DES JOACHIMS GS	G8	[redacted]	[redacted]
DES JOACHIMS GS	G8	[redacted]	[redacted]
DES JOACHIMS GS	G8	[redacted]	[redacted]
DES JOACHIMS GS	G1	[redacted]	[redacted]
DES JOACHIMS GS	G1	[redacted]	[redacted]
DES JOACHIMS GS	G2	[redacted]	[redacted]
DES JOACHIMS GS	G3	[redacted]	[redacted]
DES JOACHIMS GS	G3	[redacted]	[redacted]
DES JOACHIMS GS	G4	[redacted]	[redacted]
DES JOACHIMS GS	G4	[redacted]	[redacted]
DES JOACHIMS GS	G2	[redacted]	[redacted]
DES JOACHIMS GS	G5	[redacted]	[redacted]
DES JOACHIMS GS	G6	[redacted]	[redacted]
DES JOACHIMS GS	G7	[redacted]	[redacted]
DES JOACHIMS GS	G8	[redacted]	[redacted]
Elliott Chute GS	G1	[redacted]	[redacted]
KAKABEKA FALLS GS	G1	[redacted]	[redacted]
KAKABEKA FALLS GS	G2	[redacted]	[redacted]
KAKABEKA FALLS GS	G3	[redacted]	[redacted]
KAKABEKA FALLS GS	G4	[redacted]	[redacted]
LOWER NOTCH GS	G1	[redacted]	[redacted]
LOWER NOTCH GS	G2	[redacted]	[redacted]
LOWER NOTCH GS	G2	[redacted]	[redacted]
LOWER NOTCH GS	G1	[redacted]	[redacted]
LOWER NOTCH GS	G1	[redacted]	[redacted]
LOWER NOTCH GS	G2	[redacted]	[redacted]
LOWER NOTCH GS	G1	[redacted]	[redacted]
MANITOU FALLS GS	G1	[redacted]	[redacted]
MANITOU FALLS GS	G2	[redacted]	[redacted]
MANITOU FALLS GS	G3	[redacted]	[redacted]
MANITOU FALLS GS	G4	[redacted]	[redacted]
MANITOU FALLS GS	G5	[redacted]	[redacted]
MANITOU FALLS GS	G4	[redacted]	[redacted]
MANITOU FALLS GS	G3	[redacted]	[redacted]
Matabitchuan GS	G1	[redacted]	[redacted]
Matabitchuan GS	G2	[redacted]	[redacted]
Matabitchuan GS	G3	[redacted]	[redacted]
Matabitchuan GS	G4	[redacted]	[redacted]
McVittie GS	G1	[redacted]	[redacted]
McVittie GS	G2	[redacted]	[redacted]
Meyersburg GS	G2	[redacted]	[redacted]
Meyersburg GS	G1	[redacted]	[redacted]
MOUNTAIN CHUTE GS	G1	[redacted]	[redacted]

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
MOUNTAIN CHUTE GS	G1	[redacted]	
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G2		
MOUNTAIN CHUTE GS	G1		
MOUNTAIN CHUTE GS	G2		
OTTER RAPIDS GS	G1		
OTTER RAPIDS GS	G2		
OTTER RAPIDS GS	G3		
OTTER RAPIDS GS	G3		
OTTER RAPIDS GS	G4		
OTTER RAPIDS GS	G1		
OTTER RAPIDS GS	G1		
OTTER RAPIDS GS	G2		
OTTER RAPIDS GS	G2		
OTTER RAPIDS GS	G3		
OTTER RAPIDS GS	G4		
OTTER RAPIDS GS	G4		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
OTTER RAPIDS GS	G3	[redacted]	[redacted]
OTTER RAPIDS GS	G4	[redacted]	[redacted]
OTTER RAPIDS GS	G4	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G2	[redacted]	[redacted]
OTTO HOLDEN GS	G2	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G4	[redacted]	[redacted]
OTTO HOLDEN GS	G4	[redacted]	[redacted]
OTTO HOLDEN GS	G5	[redacted]	[redacted]
OTTO HOLDEN GS	G6	[redacted]	[redacted]
OTTO HOLDEN GS	G7	[redacted]	[redacted]
OTTO HOLDEN GS	G7	[redacted]	[redacted]
OTTO HOLDEN GS	G8	[redacted]	[redacted]
OTTO HOLDEN GS	G8	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G6	[redacted]	[redacted]
OTTO HOLDEN GS	G5	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G2	[redacted]	[redacted]
OTTO HOLDEN GS	G3	[redacted]	[redacted]
OTTO HOLDEN GS	G4	[redacted]	[redacted]
OTTO HOLDEN GS	G6	[redacted]	[redacted]
OTTO HOLDEN GS	G7	[redacted]	[redacted]
OTTO HOLDEN GS	G8	[redacted]	[redacted]
OTTO HOLDEN GS	G5	[redacted]	[redacted]
OTTO HOLDEN GS	G8	[redacted]	[redacted]
OTTO HOLDEN GS	G1	[redacted]	[redacted]
OTTO HOLDEN GS	G5	[redacted]	[redacted]
OTTO HOLDEN GS	G2	[redacted]	[redacted]
PINE PORTAGE GS	G1	[redacted]	[redacted]
PINE PORTAGE GS	G2	[redacted]	[redacted]
PINE PORTAGE GS	G3	[redacted]	[redacted]
PINE PORTAGE GS	G4	[redacted]	[redacted]
PINE PORTAGE GS	G2	[redacted]	[redacted]

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
PINE PORTAGE GS	G3	[redacted]	
PINE PORTAGE GS	G4		
PINE PORTAGE GS	G1		
PINE PORTAGE GS	G4		
R. H. SAUNDERS GS	G16		
R. H. SAUNDERS GS	G1		
R. H. SAUNDERS GS	G13		
R. H. SAUNDERS GS	G14		
R. H. SAUNDERS GS	G15		
R. H. SAUNDERS GS	G16		
R. H. SAUNDERS GS	G2		
R. H. SAUNDERS GS	G3		
R. H. SAUNDERS GS	G4		
R. H. SAUNDERS GS	G11		
R. H. SAUNDERS GS	G12		
R. H. SAUNDERS GS	G3		
R. H. SAUNDERS GS	G13		
R. H. SAUNDERS GS	G15		
R. H. SAUNDERS GS	G1		
R. H. SAUNDERS GS	G2		
R. H. SAUNDERS GS	G16		
Seymour GS	G1		
Seymour GS	G2		
Seymour GS	G3		
Seymour GS	G4		
Seymour GS	G5		
SILVER FALLS GS	G1		
SILVER FALLS GS	G1		
SIR ADAM BECK PGS	G1		
SIR ADAM BECK PGS	G1		
SIR ADAM BECK PGS	G2		
SIR ADAM BECK PGS	G2		
SIR ADAM BECK PGS	G3		
SIR ADAM BECK PGS	G3		
SIR ADAM BECK PGS	G4		
SIR ADAM BECK PGS	G4		
SIR ADAM BECK PGS	G5		
SIR ADAM BECK PGS	G5		
SIR ADAM BECK PGS	G6		
SIR ADAM BECK PGS	G6		
SIR ADAM BECK PGS	G1		
SIR ADAM BECK PGS	G1		
SIR ADAM BECK PGS	G2		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
SIR ADAM BECK PGS	G3	[redacted]	
SIR ADAM BECK PGS	G3		
SIR ADAM BECK PGS	G4		
SIR ADAM BECK PGS	G4		
SIR ADAM BECK PGS	G4		
SIR ADAM BECK PGS	G5		
SIR ADAM BECK PGS	G5		
SIR ADAM BECK PGS	G5		
SIR ADAM BECK PGS	G6		
SIR ADAM BECK PGS	G6		
SIR ADAM BECK PGS	G6		
SIR ADAM BECK PGS	G2		
SIR ADAM BECK-1 GS	G2		
SIR ADAM BECK-1 GS	G4		
SIR ADAM BECK-1 GS	G10		
SIR ADAM BECK-1 GS	G2		
SIR ADAM BECK-1 GS	G8		
SIR ADAM BECK-1 GS	G4		
SIR ADAM BECK-1 GS	G4		
SIR ADAM BECK-1 GS	G1		
SIR ADAM BECK-1 GS	G10		
SIR ADAM BECK-1 GS	G2		
SIR ADAM BECK-1 GS	G2		
SIR ADAM BECK-1 GS	G3		
SIR ADAM BECK-1 GS	G4		
SIR ADAM BECK-1 GS	G5		
SIR ADAM BECK-1 GS	G5		
SIR ADAM BECK-1 GS	G6		
SIR ADAM BECK-1 GS	G6		
SIR ADAM BECK-1 GS	G7		
SIR ADAM BECK-1 GS	G7		
SIR ADAM BECK-1 GS	G8		
SIR ADAM BECK-1 GS	G8		
SIR ADAM BECK-1 GS	G9		
SIR ADAM BECK-1 GS	G10		
SIR ADAM BECK-1 GS	G1		
SIR ADAM BECK-1 GS	G3		
SIR ADAM BECK-1 GS	G6		
SIR ADAM BECK-1 GS	G9		
SIR ADAM BECK-1 GS	G4		
SIR ADAM BECK-1 GS	G9		
SIR ADAM BECK-1 GS	G1		
SIR ADAM BECK-1 GS	G3		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
SIR ADAM BECK-1 GS	G4	[redacted]	
SIR ADAM BECK-1 GS	G6		
SIR ADAM BECK-2 GS	G11		
SIR ADAM BECK-2 GS	G12		
SIR ADAM BECK-2 GS	G13		
SIR ADAM BECK-2 GS	G14		
SIR ADAM BECK-2 GS	G15		
SIR ADAM BECK-2 GS	G16		
SIR ADAM BECK-2 GS	G17		
SIR ADAM BECK-2 GS	G18		
SIR ADAM BECK-2 GS	G19		
SIR ADAM BECK-2 GS	G20		
SIR ADAM BECK-2 GS	G21		
SIR ADAM BECK-2 GS	G22		
SIR ADAM BECK-2 GS	G25		
SIR ADAM BECK-2 GS	G26		
SIR ADAM BECK-2 GS	G11		
SIR ADAM BECK-2 GS	G12		
SIR ADAM BECK-2 GS	G13		
SIR ADAM BECK-2 GS	G14		
SIR ADAM BECK-2 GS	G17		
SIR ADAM BECK-2 GS	G17		
SIR ADAM BECK-2 GS	G18		
SIR ADAM BECK-2 GS	G18		
SIR ADAM BECK-2 GS	G19		
SIR ADAM BECK-2 GS	G20		
SIR ADAM BECK-2 GS	G13		
SIR ADAM BECK-2 GS	G14		
SIR ADAM BECK-2 GS	G23		
SIR ADAM BECK-2 GS	G23		
SIR ADAM BECK-2 GS	G23		
SIR ADAM BECK-2 GS	G24		
SIR ADAM BECK-2 GS	G24		
SIR ADAM BECK-2 GS	G24		
SIR ADAM BECK-2 GS	G19		
SIR ADAM BECK-2 GS	G20		
SIR ADAM BECK-2 GS	G19		
SIR ADAM BECK-2 GS	G20		
South Falls GS	G3		
South Falls GS	G1		
South Falls GS	G2		
South Falls GS	G3		
South Falls GS	G1		

Station Name	Equipment	Start Date	Outage Length Duration In 2027 (Days)
STEWARTVILLE GS	G1	[redacted]	
STEWARTVILLE GS	G2		
STEWARTVILLE GS	G3		
STEWARTVILLE GS	G1		
STEWARTVILLE GS	G3		
STEWARTVILLE GS	G5		
STEWARTVILLE GS	G5		
STEWARTVILLE GS	G4		
Stinson GS	G1		
Stinson GS	G2		
Stinson GS	G1		
Stinson GS	G2		
WHITEDOG FALLS GS	G1		
WHITEDOG FALLS GS	G1		
WHITEDOG FALLS GS	G2		
WHITEDOG FALLS GS	G2		
WHITEDOG FALLS GS	G3		
WHITEDOG FALLS GS	G3		

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2028-2031 Regulated Hydroelectric Outage Data

Station Name	Equipment	Start Date	Outage Duration (Days)
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G1	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G2	[redacted]	[redacted]
ABITIBI CANYON GS	G3	[redacted]	[redacted]
ABITIBI CANYON GS	G3	[redacted]	[redacted]

ABITIBI CANYON GS	G3	[redacted]
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G3	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G4	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	

ABITIBI CANYON GS	G5	[redacted]
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
ABITIBI CANYON GS	G5	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G1	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
AGUASABON GS	G2	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G1	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	
ALEXANDER GS	G2	

ALEXANDER GS	G2	[redacted]
ALEXANDER GS	G2	[redacted]
ALEXANDER GS	G2	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G3	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G4	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ALEXANDER GS	G5	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G1	[redacted]
ARNPRIOR GS	G2	[redacted]
ARNPRIOR GS	G2	[redacted]
ARNPRIOR GS	G2	[redacted]
ARNPRIOR GS	G2	[redacted]
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R. H. SAUNDERS GS	G9	
SILVER FALLS GS	G1	
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R. H. SAUNDERS GS	G5	
R. H. SAUNDERS GS	G6	
R. H. SAUNDERS GS	G7	
R. H. SAUNDERS GS	G8	
SILVER FALLS GS	G1	
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Big Eddy GS	G1	
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Big Eddy GS	G2	
Bingham Chute GS	G1	
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High Falls GS	G3	
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McVittie GS	G2	
Merrickville GS	G1	
Meyersburg GS	G3	
Ranney Falls GS	G2	
Seymour GS	G4	
Seymour GS	G5	
Seymour GS	G5	
Sills Island GS	G2	
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OTTO HOLDEN GS	G4	[redacted]
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R. H. SAUNDERS GS	G4	[redacted]
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R. H. SAUNDERS GS	G7	
R. H. SAUNDERS GS	G8	
MOUNTAIN CHUTE GS	G1	
MOUNTAIN CHUTE GS	G2	
SIR ADAM BECK-1 GS	G8	
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SIR ADAM BECK PGS	G1
SIR ADAM BECK PGS	G1
SIR ADAM BECK PGS	G1
SIR ADAM BECK PGS	G2
SIR ADAM BECK PGS	G2
SIR ADAM BECK PGS	G2
SIR ADAM BECK PGS	G2
SIR ADAM BECK PGS	G2
SIR ADAM BECK PGS	G2

SIR ADAM BECK PGS	G3	[redacted]
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SIR ADAM BECK PGS	G4	
SIR ADAM BECK PGS	G4	
SIR ADAM BECK PGS	G4	
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SIR ADAM BECK PGS	G5	
SIR ADAM BECK PGS	G5	
SIR ADAM BECK PGS	G5	
SIR ADAM BECK PGS	G5	
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SIR ADAM BECK PGS	G6	
SIR ADAM BECK PGS	G6	
SIR ADAM BECK PGS	G6	
SIR ADAM BECK PGS	G6	
SIR ADAM BECK PGS	G6	
SIR ADAM BECK-1 GS	G1	
SIR ADAM BECK-1 GS	G10	
SIR ADAM BECK-1 GS	G10	
SIR ADAM BECK-1 GS	G2	
SIR ADAM BECK-1 GS	G3	
SIR ADAM BECK-1 GS	G4	
SIR ADAM BECK-1 GS	G5	
SIR ADAM BECK-1 GS	G6	
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SIR ADAM BECK-1 GS	G8	
SIR ADAM BECK-1 GS	G9	
SIR ADAM BECK-2 GS	G11	
SIR ADAM BECK-2 GS	G12	
SIR ADAM BECK-2 GS	G13	
SIR ADAM BECK-2 GS	G13	
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SIR ADAM BECK-2 GS	G23	
SIR ADAM BECK-2 GS	G24	
SIR ADAM BECK-2 GS	G25	
SIR ADAM BECK-2 GS	G26	
DECEW FALLS GS	G5	
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DECEW FALLS 2 GS	G2	
DECEW FALLS 2 GS	G1	
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DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS 2 GS	G2	
DECEW FALLS 2 GS	G1	
DECEW FALLS 2 GS	G2	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	

DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	
DECEW FALLS 2 GS	G1	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
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DECEW FALLS GS	G7	
DECEW FALLS GS	G8	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	

DECEW FALLS GS	G7	[redacted]
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DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	[redacted]
DECEW FALLS 2 GS	G1	[redacted]
DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	[redacted]
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DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
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DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	[redacted]
DECEW FALLS 2 GS	G1	[redacted]
DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	[redacted]
DECEW FALLS 2 GS	G1	[redacted]
DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
DECEW FALLS GS	G7	[redacted]
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DECEW FALLS GS	G5	[redacted]
DECEW FALLS GS	G6	[redacted]
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DECEW FALLS GS	G6	[redacted]
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DECEW FALLS 2 GS	G2	
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DECEW FALLS 2 GS	G2	
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DECEW FALLS 2 GS	G2	
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DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
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DECEW FALLS 2 GS	G2	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
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DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G7	
DECEW FALLS GS	G8	
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DECEW FALLS 2 GS	G2	
DECEW FALLS 2 GS	G2	
DECEW FALLS GS	G5	
DECEW FALLS GS	G6	
DECEW FALLS GS	G8	
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DECEW FALLS GS	G6	
DECEW FALLS GS	G8	
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DECEW FALLS GS	G7	
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DECEW FALLS GS	G6	[redacted]
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DECEW FALLS GS	G6	
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DECEW FALLS GS	G7	
DECEW FALLS GS	G8	

SEC Interrogatory #129

Interrogatory

Reference:
[Auditor General of Ontario, 2022 Report, Value-for-Money Audit: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations; Auditor General of Ontario, 2024 Annual Report, Follow-up: Management and Maintenance of Hydroelectric Generating Stations]

Preamble:

In its 2022 Annual Report, the Auditor General made the following recommendation:

> "To protect the interests of Ontario ratepayers, we recommend that Ontario Power Generation collaborate with the Independent Electricity System Operator and the Ontario Energy Board to assess options for more cost-effective ways to be compensated for surplus baseload generation conditions, such as covering only fixed costs when hydroelectric generating stations are requested to spill water in order to curtail production."

In its 2024 Annual Report, the Auditor General Report wrote regarding the lack of implementation of the recommendation in its 2022 Report:

> "While OPG anticipates that the OEB will review the methodology for calculating the Hydroelectric Surplus Baseload Generation Variance Account, this review will not include an assessment that will address this recommended action. This is because the methodology review is intended to assess options to reduce amounts recorded in this Hydroelectric Surplus Baseload Generation Variance Account instead of options to adjust the compensation methodology."

Question(s):

a) Has OPG undertaken any analysis regarding where there are more cost-effective ways to compensate it with respect to SBG? If so, please provide. If not, please explain why not.

b) Please explain why OPG has not collaborated with the IESO to date regarding an appropriate compensation mechanism for forgone electricity production due to SBG conditions.

c) What methodological review is OPG referring to in the 2024 follow-up review and why does it believe that it does not include compensation methodology?

Response

a) As highlighted in its response to the 2024 Auditor General Report, OPG already excludes its variable cost, gross revenue charge, which is incurred only when OPG generates electricity. Additionally, in most cases OPG does not shut down its stations when forgoing energy in the form of hydroelectric spill as a result of surplus baseload generation (“SBG”) conditions. Accordingly, OPG is unable to identify any measurable changes to its cost structure when responding to dispatches that result in SBG spill.

As part of this application, OPG filed a Hydroelectric Surplus Baseload Generation Variance Account (“SBGVA”) Study[1] evaluating multiple options to reduce its overall SBG spill and associated amounts booked in the SBGVA. The Study focused on regulatory and market mechanisms, including those requiring further approval by external entities. Based on its detailed evaluation of three options, the SBGVA Study concluded that the options presented in this study offer pathways to reduce SBGVA amounts and total system costs and demonstrate that targeted adjustments to PGS cost treatment and hydroelectric incentive mechanism net revenue sharing can improve incentives for OPG to time-shift generation in ways that lower spill and benefit ratepayers.

b) As described in part a), OPG filed an SBGVA Study evaluating multiple options to reduce the overall amounts for SBG spill. The Study, including its recommendations, were shared with and reviewed by the IESO in advance of filing the Application and is presented for consideration to the OEB in this proceeding.[2]

c) The “methodology review” cited by the Auditor General refers to the OEB’s directive to OPG in the EB-2023-0336 Decision and Order. Specifically, the OEB instructed OPG to study options to reduce SBGVA amounts on a going forward basis and consider reasonable options to better incentivize OPG to minimize total system costs.[3] In accordance with the OEB’s directive, the SBGVA Study described in part a) explores options to reduce the amounts booked in the SBGVA, rather than an adjustment to the compensation methodology approved in EB-2023-0336.

[1] Refer to Ex. E1-2-1, Attachment 1
[2] Refer to Ex. E1-2-1, Attachment 1, p. 36
[3] EB-2023-0336, Decision and Order, June 13, 2024, p .5.

SEC Interrogatory #130

Interrogatory

Reference:
E1-2-1, p. 8, 9, 13, 15

Question(s):

Please update Charts 2-5 to include the latest month available.

Response

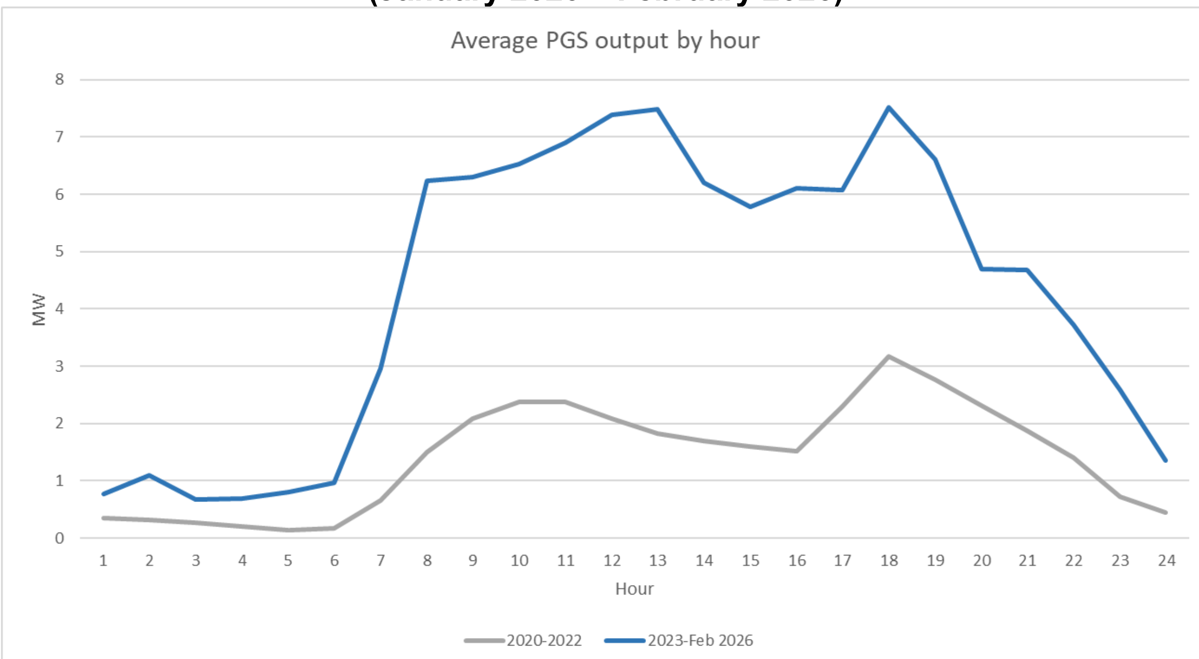
Updated versions of Charts 2, 3, and 5 are provided below. Refer to Ex. L-E1-Staff-142 for an updated version of Chart 4 – HIM Payments in Market Renewal.

Updated Ex. E1-2-1 Chart 2
SBG Spill Booked to SBGVA (GWh)[1]

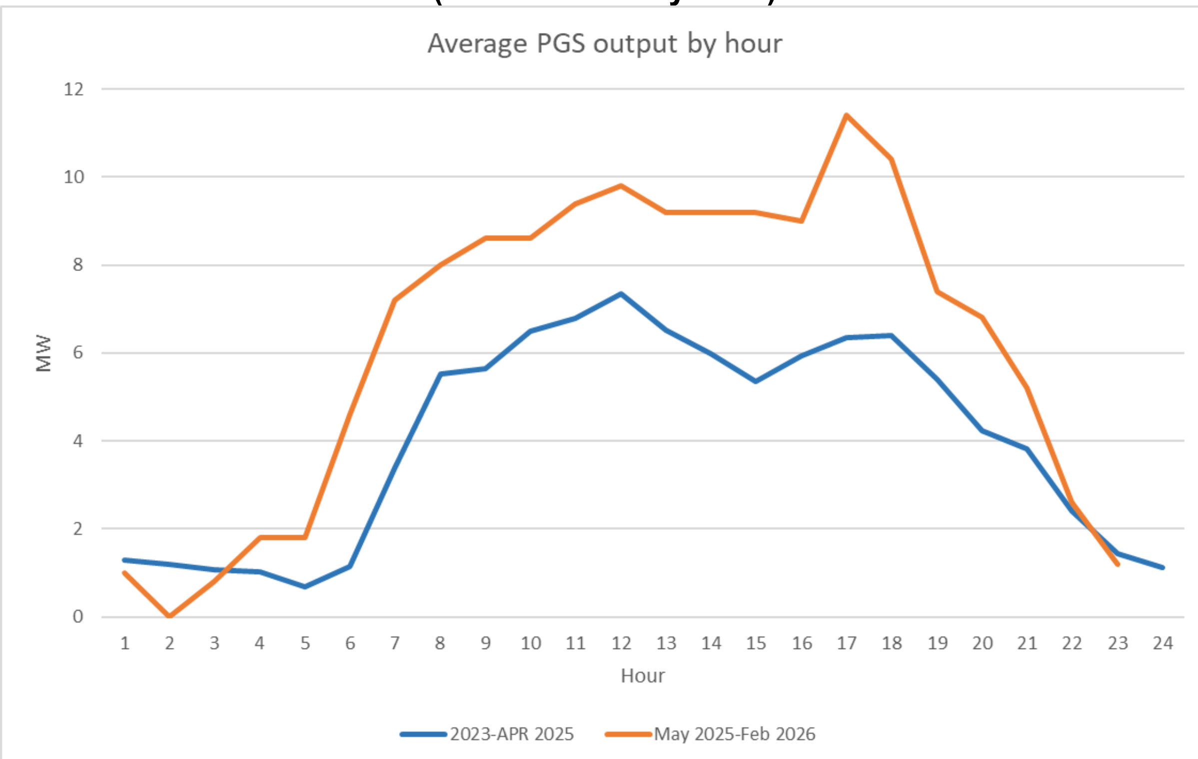
	2021	2022	2023	2024	2025	2026	Average
January	195	51	54	3	5	3	52
February	118	72	152	15	0	7	61
March	258	74	85	20	48		97
April	399	276	199	77	131		216
May	299	353	289	44	398		277
June	134	283	31	68	84		120
July	108	32	1	13	33		37
August	32	30	18	9	12		20
September	130	77	9	17	20		51
October	99	65	92	17	12		57
November	48	216	40	49	3		71
December	62	62	6	17	4		30
Total	**1,882**	**1,592**	**977**	**350**	**751**	**10**	**1,090**

[1] The SBGVA amounts associated with spill for May to February 2026 as presented in Chart 2 are subject to a monthly $0.6M reduction in accordance with the OEB-approved EB-2023-0336 Settlement Proposal, which is applicable until the effective date of the payment amounts order in this Application.

pdated Ex. E1-2-1 Chart 3
Average Pump Generating Station Output by Hour
(January 2020 – February 2026)



Updated Ex. E1-2-1 Chart 5
Average Pump Generating Station Output by Hour
(2023 – February 2026)



SEC Interrogatory #131

Interrogatory

Reference:
E1-2-1

Question(s):

With respect to the proposed changes to Hydroelectric Incentive Mechanism ("HIM") revenue sharing methodology:

a) [p.13] As it related to HIM payments in Market Renewal, "OPG has taken a measured approach in interpreting these results alongside its longer-term modelled expectations of market operations", and that "[a]s the IESO noted in its update on Renewed Market performance and operations: the ability to draw conclusions at this point is still limited". On that basis, please explain why it is appropriate to change the HIM revenue sharing methodology now.

b) [p.17-18; EB-2023-0336, H-SEC-04c] Please reconcile OPG's proposed changes to the HIM with its statement that in EB-2023-0336 that "HIM revenue sharing is not considered in the economic decision making for PGS operations".

Response

a) Refer to Ex. L-G1-CCC-096.

b) HIM revenue sharing is not considered in the economic decision making for PGS operations unless and until the HIM revenue threshold is exceeded, at which point incremental HIM revenues are shared with ratepayers through monthly entries to the Hydroelectric Incentive Mechanism Variance Account. An illustrative example is provided at Ex. E1-2-1, Attachment 1, p. 21. In this example, the "Adjustment for Incremental HIM Net Revenue Sharing" is included as a cost component in PGS economic decision-making only once HIM revenues exceed the applicable threshold.

   As described in Ex. L-E1-CCC-064 part b), OPG's HIM revenues have never exceeded the $54.5M threshold established in EB-2013-0321. As such, as of the time of OPG's response to Ex. L-H-SEC-04 part c) that was provided in EB-2023-0336, OPG has not included HIM revenue sharing in the economic decision-making for PGS operations.

OPG’s proposed changes to the HIM address the impact that retaining and resetting the threshold could have on the economics of the PGS. Accordingly, OPG’s proposal is not based on historical outcomes but rather on mitigating a potential barrier that could reduce PGS utilization.

SEC Interrogatory #132

Interrogatory

Reference:
E1-2-1, p. 16

Question(s):

a) Please provide all underlying calculations included in Chart 6. For the calculation of the Payments for Non-OPG Supplier Generation, please provide a detailed explanation of the methodology, all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files.

Response

a) The modeling used in OPG's forecast of the HIM customer benefit in EB-2013-0321 (Ex. E1-2-1, Section 5.1) was modified to incorporate features of the Renewed Market[1] and proposals submitted in this Application and used to forecast the HIM customer benefit presented in Chart 6. The proprietary models comprise:
   - A custom transmission network model and least-cost dispatch algorithm;
   - OPG's offer prices and proprietary assumptions for offer strategies of other market participants;
   - Proprietary hourly weather normal profiles of all weather-driven input parameters including electricity demand, wind and solar generation for Ontario and the Northeast interconnect; and
   - Detailed modeling of Ontario's hydroelectric system.

   The estimated benefit accruing to Ontario customers because of the HIM has been forecasted by comparing two scenarios:
   1) OPG's offer strategy incented by the HIM to time-shift regulated hydroelectric production in response to market prices; and
   2) A base case where absent an incentive, OPG does not time-shift energy to the same extent.[2]

   The two scenarios were compared to determine changes to Total Customer Cost ("TCC").

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[1] Ex. G1-1-1 page 9.
[2] Refer to Ex. L-E1-Staff-147 part a).

The modelling outputs underpinning the HIM customer benefit analysis in Ex. E1-2-1, p. 16, Chart 6 are provided in Chart 1 below. The value in each year represents the change between the scenarios obtained by subtracting the outputs of the base scenario from the HIM scenario.

Chart 1 – HIM Customer Benefit Modeling Analysis Outputs

Revenue		2026	2027
Export Revenue	$M	2.9	1.7

Cost		2026	2027
Ontario Zonal Price	$/MWh	0.08	(3.26)
Import Cost	$M	(10.5)	(114.2)
Non-OPG Gas Cost	$M	(29.7)	5.5
OPG Gas Cost	$M	(0.9)	(8.2)
Wind Cost	$M	2.9	1.7
Wind SBG Cost	$M	(2.9)	(1.7)
OPG Hydro SBG Cost	$M	(4.4)	(0.9)
OPG Hydro Cost	$M	4.1	(2.5)
Total Customer Cost (excluding HIM)	$M	(51.8)	(153.5)

Production		2026	2027
Imports	TWh	0.07	(0.17)
Non-OPG Gas	TWh	(0.38)	0.19
Wind	TWh	0.02	0.01
OPG Hydro	TWh	0.09	0.00
OPG Gas	TWh	(0.01)	(0.02)
Total OPG Supply	TWh	0.09	(0.02)
Wind SBG	TWh	(0.02)	(0.01)
OPG Hydro SBG	TWh	(0.13)	(0.03)
Exports	TWh	(0.19)	0.03
Imports	TWh	0.07	(0.17)

The decrease in TCC of $51.8M in 2026 and $153.5M in 2027 in the HIM Scenario is primarily due to:

- Savings related to fewer high-priced imports during peak periods;
- Savings related to reduction in natural gas dispatch during peak periods;
- Savings from reduction in SBGVA amounts because of lower spill; and
- Increased export revenue, which lowers overall system costs.

OPG declines to disclose the underlying model, data files, or source code, as these constitute proprietary materials incorporating OPG's specialized electricity market simulation algorithm developed for commercial purposes, which is both highly complex and commercially sensitive, necessitating specialized knowledge and training for effective interpretation and operation. The model's size, level of detail, and structural complexity present a significant practical barrier to disclosure. Execution of the model involves more than 25,000 lines of code and requires coordinated processing across multiple servers over several hours to complete a single run. This level of detail is further reflected in the volume of underlying data and embedded calculations, including thousands of formulas and more than 400 hourly input datasets, each containing in excess of 175,000 data points. As a result, the model is highly resource-intensive and not readily transferable or usable without substantial effort to replicate the necessary computing environment and technical expertise. Given its complexity, the model would offer minimal probative value in this proceeding while introducing unnecessary commercial risk and additional regulatory costs into the process.

SEC Interrogatory #133

Interrogatory

Reference:
E1-2-1, p. 17

Preamble:

The evidence states "As a result, Ontario Zonal Prices are projected to rise, increasing the value of incremental time shifted hydro production and the customer benefit in 2027."

Question(s):

Please provide OPG's forecast Ontario Zonal Price through the end of 2027.

Response

For the reasons articulated in Ex. L-E1-SEC-132, OPG declines to provide the forecasted 2027 Ontario Zonal Price. However, OPG notes that the change in benefit from 2026 to 2027 is $11.05/MWh. The change in benefit approach allows relevant information to be disclosed and considered on the public record without raising the commercial sensitivity and proprietary data concerns outlined in Ex. L-E1-SEC-132.

SEC Interrogatory #134

Interrogatory

Reference:
E1-2-1, Attachment 1, p. 8

Question(s):

Please explain how OPG forecasts the amount of SBG. Please provide all underlying calculations, including all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files.

Response

OPG derives forecast spill from its regulated hydroelectric resources due to SBG using the following general process:

- OPG uses its hourly electricity market simulation model to forecast SBG using a least cost optimization dispatch model. Baseload energy supply from OPG and non-OPG generating facilities exceeding Market Demand (Ontario Demand plus exports) results in surplus baseload generation that is not dispatched.
- To derive the SBG that must be managed by its regulated hydro assets, OPG makes assumptions regarding economic dispatch order, including offer price and quantity pairs of non-OPG generators in Ontario and neighboring electricity markets.

OPG declines to provide the underlying calculations and model as the forecast of SBG is derived from a proprietary model. Refer to Ex. L-E1-SEC-132 for a detailed explanation of the complexity and commercial sensitivity of this model.

SEC Interrogatory #135

Interrogatory

Reference:
E1-2-1, Attachment 1, p. 22

Question(s):

Please provide an analysis, all underlying calculations, including all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files, of how much more often the PGS would have, or will be, cycled, if OPG's proposed changes to the HIM revenue sharing mechanism had been/will be implemented.

Response

The requested analysis cannot be provided, as it would require OPG to model and evaluate a range of hypothetical market outcomes that differ from OPG's forecast, specifically instances when OPG's HIM revenues are higher than expected. This would necessitate the development and application of a probabilistic modelling framework that incorporates simulated scenarios of demand, generation, gas prices and other critical inputs to simulate a wide distribution of potential market conditions.

OPG does not maintain a probabilistic model for forecasting PGS cycling behaviour under alternative HIM constructs, nor was such modelling required to support the evidence filed in this proceeding. OPG's filed forecasts are based on deterministic assumptions reflecting expected conditions, rather than a range of higher-than-forecast HIM revenue outcomes. Accordingly, undertaking the requested analysis would require the development of new modelling tools, the specification and validation of input distributions, and the execution and analysis of numerous simulation runs, representing a significant effort that would take several months to complete.

SEC Interrogatory #136

Interrogatory

Reference:
E1-2-1, Attachment 1, p. 22
Decision and Order (EB-2013-0321), November 20, 2024, p. 12-13

Question(s):

Please explain what has changed since the OEB's Decision in EB-2013-0321 regarding the HIM, and the structure of the revenue sharing that warrant the OEB to make the changes OPG has proposed.

Response

Refer to Ex. L-G1-CCC-096.

Board Staff Interrogatory #135

Interrogatory

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

Preamble:

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

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

Question(s):

a) Please provide an updated table as in Reference 1, updating 2025 for actual productions.

b) The 2026 budget pre-spill production forecast at Reference 1 is 32.7641 TWh while the 2026 budget pre-spill production forecast at Reference 2 is 32.9763 TWh. Please resolve this discrepancy, and update Reference 2 accordingly.

Response

a) OPG has provided an updated version of Ex. E1-1-1, Table 1 reflecting 2025 actual production in Ex. L-A1-CCC-001.

b) Exhibit E1-1-1, Table 1 provides the 2026 budget pre-spill production forecast as per OPG's 2025-2031 Business Plan.

   By contrast, Ex. I1-1-2, Table 2 utilizes the pre-spill production forecast approved in EB-2013-0321 for the purposes of assessing the year-over-year change in OPG's weighted average payment amount. This approach is consistent with the Decision and Order, EB-2023-0336, Appendix A, Table 4, Line 4.

Board Staff Interrogatory #136

Interrogatory

Reference:
Ref 1: Exhibit E1 / Tab 1 / Schedule 1 / pp. 4-7
Ref 2: Exhibit D1 / Tab 1 / Schedule 1 / pp. 3-4
Ref 3: Exhibit F1 / Tab 1 / Schedule 1 / pp. 5-15

Preamble:

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

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

Question(s):

a) Please confirm there is incremental capacity expected for the regulated hydroelectric generating stations from refurbishment projects and redevelopment projects during the entire 2027-2031 forecast period. If not confirmed, please explain.

b) Please confirm if the incremental capacity that will come into service between 2027 – 2031 is reflected in the 2027 production forecast. If not, please explain how each year's production forecast between 2028 – 2031 would differ from the 2027 production forecast.

c) Please confirm that OPG proposes to use the 2027 forecasted energy production approved by the OEB in this application to calculate production deviations for entries in the Water Conditions Variance Account during 2027-2031. If not confirmed, please explain. If confirmed, please explain how OPG plans to account for the increase in production resulting from the capital projects in the 2028-2031 period.

Response

a) Confirmed. Please refer to Ex. L-A1-Staff-007, part a), for further details.

b) Only production associated with incremental capacity from refurbishment and redevelopment projects expected to be in service in 2027 has been included in the 2027 production forecast. In the context of incremental capacity from refurbishment and redevelopment projects that enter service in 2028-2031, the production forecast for those years would differ from the 2027 forecast to the extent such increased capacity each year is realized as production, based on flow assumptions and impact of outages for each year.

c) Confirmed, as further discussed in Ex. H1-1-1, Section 5.1. As discussed in Ex. A1-3-2, for the years 2028-2031, OPG proposes that the hydroelectric payment amount be adjusted annually according to a mechanistic price-cap adjustment consistent with EB-2016-0152. OPG is not proposing an additional mechanism to account for any year-over-year differences in the production forecast other than continuing with the Hydroelectric Water Conditions Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account, and requesting the Change of Laws Deferral Account (OPG).

Board Staff Interrogatory #137

Interrogatory

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

Preamble:

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

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

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

Question(s):

a) Please explain the detailed mechanism of how the unplanned outage spill is quantified and applied to the final production forecast amount.

b) For the other six dispatchable regulated hydroelectric generating stations in the Niagara, Welland, and St. Lawrence river systems, please explain if the methodology has also been updated to account for unplanned outage spill. If not, please explain why.

c) Please confirm whether the production at the NHC is considered in the Niagara Utilization Monthly Model that is being used to forecast the Sir Adam Beck Complex production. If not, please explain. If it is considered, what is the impact to hydroelectric production in each month of the 2027 production forecast.

d) Please quantify the impact of the production forecasting modification described at Reference 1 by Region and month of the 2027 production forecast.

e) Please quantify the impact of the production forecasting modification described at Reference 3 by Region and month of the 2027 production forecast.

f) For each modification to the production forecast, please explain the methodology of the analysis that determined the impact or input into the 2027 hydroelectric production forecast. For example, what is the historical time period of that analysis? Please describe the analysis for each region.

Response

a) Unplanned outage spill is quantified by calculating forgone production attributable to reduced station capacity due to unplanned outages. The methodology is performed for each hour at each applicable station using the tools built for the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") spill calculations to ensure consistency in spill accounting. The hourly data is totaled for each month. The monthly average of unplanned outage spill based on five years of historical analysis from 2019-2023 is subtracted from the forecast production of each of the 21 stations cited in Reference 1.

b) The production forecast for the other six dispatchable regulated hydroelectric generating stations on the Niagara, Welland, and St. Lawrence river systems does not include a reduction based on the unplanned outage spill methodology described in part a) above.

Water directed to the DeCew Falls 1 & 2 generating stations via the Welland Canal considers unit availability, including when unit availability is impacted by unplanned outages. As the directed water is reduced to reflect unplanned outages, quantification of spill is not applicable or required.

For the Sir Adam Beck 1 and 2 generating stations, unplanned outages are implicitly accounted for in the Niagara Utilization Monthly Model ("NUMM") through the hindcast calibration of the model. Instances when actual production is impacted by forced outages form part of the difference between modelled production (using actual flows) and actual production and in turn are included in the overall adjustment of the Sir Adam Beck generating stations' forecast as described in Ex. E1-1-1, Sections 3.1 and 3.2.

As stated in part a), the methodology for quantifying unplanned outage spill uses the tools developed for the SBGVA spill calculation. As R.H. Saunders GS is not included in the SBGVA, historic unplanned outage spill was not quantifiable, and therefore no adjustment was made. OPG notes that based on forecast flows, in general, unplanned outages are not expected to cause forgone production at R.H. Saunders GS as water would be directed to other available units.

c) Not confirmed. While regulation services are incorporated in NUMM to set the production forecast at the Sir Adam Beck Complex as described in Ex. E1-1-1, Section 3.2, no separate reduction to the production forecast is needed for the Niagara Hydrogen Centre ("NHC") production to account for energy used to produce hydrogen. As described in Ex. G1-1-1, Section 3.3.1, the NHC will make use of energy resulting from otherwise Unutilized Water from the existing regulation services provided at Sir Adam Beck 2 GS.

As described in Ex. E-1-1, Section 3.2, the NHC will also consume behind-the-meter energy from Sir Adam Beck 2 GS for station-service and commissioning loads that will not be supplied by Unutilized Water. There is no adjustment made to reduce the production forecast for this consumption.

d) The requested information is provided in Chart 1 below.

Chart 1 –
Unplanned Outage Spill (TWh) – 2027 Test Year

Line No.	Operating Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Niagara Region**	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Eastern Region**	0.01	0.00	0.00	0.02	0.01	0.01	0.01	0.00	0.00	0.02	0.02	0.00	0.12
3	**Western Region**	0.01	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.08
4	**Total**	**0.02**	**0.01**	**0.01**	**0.02**	**0.02**	**0.02**	**0.02**	**0.01**	**0.01**	**0.02**	**0.03**	**0.01**	**0.19**

e) The requested information is provided in Chart 2 below.

Chart 2 –
Renewed Market – Non-SBGVA Eligible Market Spill (TWh) – 2027 Test Year

Line No.	Operating Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Niagara Region**	0.06	0.03	0.05	0.02	0.03	0.05	0.05	0.03	0.03	0.04	0.05	0.03	0.47
2	**Eastern Region**	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.01	0.02	0.00	0.09
3	**Western Region**	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.08
4	**Total**	**0.07**	**0.04**	**0.05**	**0.03**	**0.06**	**0.07**	**0.07**	**0.04**	**0.03**	**0.05**	**0.07**	**0.04**	**0.63**

f) The forecast used in this Application continues the forecast methodology used in EB-2013-0321, but updates have been made to improve the accuracy of the forecast by accounting for the impact of unplanned outage spill, non-SBGVA eligible market spill, and condense mode operations.

The methodology for unplanned outage spill is described in part a) and the associated forecast adjustment is provided in part d).

Non-SBGVA eligible market spill describes a category of hydroelectric spill that occurs when hydroelectric energy offered into the IESO Administered Market by OPG is not dispatched by the IESO despite the absence of market prices associated with SBG conditions (i.e., market prices were higher than a station's GRC). In advance of the implementation of the Renewed Market, as described in Ex. E1-2-1, Section 4.3, OPG calculated the monthly proportion of time when a station's Shadow Price[1] did not fall below its GRC while generation was scheduled down[2] for the 2019-2023 period. This proportion was then applied at the station level to the five-year monthly average of market constraint spill[3] and the resultant monthly values, as presented in part e) above, were subtracted from the hydroelectric production forecast for all regulated hydroelectric stations.

[1] Shadow Prices in the IESO Legacy Market are analogous to the Renewed Market's LMP as they reflect the marginal cost of generation on a nodal basis in the constrained run of the DSO.
[2] "Scheduled down" is referring to times when generation was economic and scheduled in the Unconstrained run but subsequently absent from the Constrained run in the IESO Legacy Market.
[3] Market constraint spill is further explained in Ex. L-E1-Staff-149 part b).

Additionally, using the tools built for SBGVA spill calculations to ensure consistency in spill accounting, OPG identified spill that occurred outside SBG conditions but was not directly associated with scheduling down over the 2019-2023 period. The production forecast for each station was adjusted by the monthly average of this spill, which exists within the capacity of a station but is not associated with a specific market event. This modification was not applied at Sir Adam Beck 1 and 2 generating stations, as these spill amounts are implicitly accounted in the NUMM through the hindcast calibration of the model, similar to what was described in part b) above. The associated forecast adjustment is 0.16 TWh for the 2027 test year and is incremental to the amounts presented in part e) above.

A monthly average of condense mode operations load has been calculated at the station level using IESO metered values, where the average of the annual totals for years in period 2019-2023 is converted to a monthly average. The resultant station level values are applied as an adjustment to the 2027 regulated hydroelectric production forecast. The methodology is consistently applied to the 21 stations of the Eastern and Western regions stated in Reference 1, and R.H. Saunders GS. The associated forecast adjustment is 0.08 TWh for the 2027 test year. This modification was not applied at Sir Adam Beck 1 and 2 Generating Stations, as condense mode operations load are implicitly accounted in the NUMM through the hindcast calibration of the model, similar to what was described in part b) above.

The above modifications have been made since EB-2013-0321 in an effort to continually improve the accuracy of OPG’s hydroelectric production forecast. These adjustments consider market changes and the functionality of the SBGVA to ensure there is no double counting in compensation for forgone generation.

Board Staff Interrogatory #138

Interrogatory

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

Preamble:

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

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

Table 1 – Water Conditions Variance Account Summary

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

Question(s):

a) Please confirm the values presented in Table 1: Water Conditions Variance Account Summary. If not confirmed, please provide the updated values.

b) Please explain how OPG has considered the consistent trend, seen in Table 1, of higher flows than forecast in developing the 2027 test year production forecast.

Response

a) Confirmed.

b) OPG has provided a discussion of trends in historical flows between 2016-2024 at Ex. E1-1-2, Section 4.0. Additionally, OPG has updated Chart 1 below which extends Table 1 provided in the question to include the 2025 actuals.

The variances noted in Table 1 of the question are largely attributable to the Niagara River which experienced a period of higher-than-average flows from 2017 to 2023, after which flow levels began to return to the long-term average. As noted in Ex. E1-1-2, Section 3.0, Niagara River flows in 2026 were expected to return to long-term average, and at the time of this response, are currently already below long-term average. The 2027 test year Niagara River production forecast was based on long-term average flows, which included actual flows for the 2016-2023 period.

The 2027 production forecast at the remaining regulated hydroelectric facilities utilized the 30-year historical median flows, which included actual flows for the 2016-2023 period. As noted in Ex. E1-1-1, Section 3.4, this is a change in methodology from EB-2013-0321.

Chart 2 –
Water Conditions Variance Account Summary Including 2025 Actuals

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Production (TWh)	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4
Actual Calculated Production (TWh)	33.6	35.7	34.0	34.6	34.7	31.7	34.8	33.9	33.7	32.0
Variance (TWh)	**-1.1**	**-3.3**	**-1.6**	**-2.1**	**-2.2**	**0.8**	**-2.4**	**-1.5**	**-1.2**	**0.4**

Board Staff Interrogatory #140

Interrogatory

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

Preamble:

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

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

[redacted]						
Hydroelectric Unit Availability (%)	89	88	86	86.6	88.2	88.4
Pre-spill Production (TWh)	33.8	35.9	33.0	33.8	34.6	30.9

[redacted]						
Hydroelectric Unit Availability (%)	86.9	85.4	85.8			
Pre-spill Production (TWh)	32.7	32.4	32.8		32.8	32.5

Question(s):

a) Please confirm the values presented in Table 1: Unit Availability and Pre-spill Hydroelectric Production Amount. If not, please provide correct values.

b) Please provide the actual Hydroelectric Unit Availability (%) and the actual Pre-spill Production (TWh) amounts for the year 2025.

c) Please provide the Hydroelectric Unit Availability (%) used in the year of 2026 and 2027 for the production forecast.

d) For the 2026 and 2027 forecast years, please identify the generating stations that have any instances of production being limited by the availability capacity. For each of those stations, please identify the percentage of time in the forecast year where the station is limited by the capacity of the available units.

Response

a), b) and c)

Part a) is not confirmed. OPG is unable to identify the source of the numbers included in Table 1. Chart 1 below provides the 2016-2027 pre-spill production and regulated hydroelectric Availabilities.[1] Chart 1 reflects 2025 actual Pre-spill Production and actual regulated hydroelectric Availability, and 2026-2027 regulated hydroelectric unit Availability targets, aligned with Ex. F1-1-1, Section 4.3.1, Chart 7.

OPG notes that while the regulated hydroelectric production forecast considers regulated hydroelectric availability, it does not utilize the Availability metric as an input. Please refer to Ex. E1-1-1 for further details on the production forecast methodology.

Chart 1 –
Availability and Pre-spill Regulated Hydroelectric Production Amount[2]

	2016	2017	2018	2019	2020	2021
Hydroelectric Availability (%)	89.0	88.0	86.0	86.6	88.8	88.4
Pre-spill Production (TWh)	33.7	35.9	33.0	33.8	34.6	30.9
	2022	**2023**	**2024**	**2025**	**2026**	**2027**
Hydroelectric Availability (%)	87.8	85.4	85.2	85.5	87.4	83.8
Pre-spill Production (TWh)	32.7	32.4	32.8	31.6	32.8	32.5

d) For the 27 hydroelectric stations connected to the IESO-controlled grid as noted in Ex. E1-1-1, Attachment 1, the percentage of time in the forecast year where the station's production capability is expected to be limited by the capacity of available units has been provided in Chart 2 below. Note that this percentage is inclusive of times when forecast flows exceed the full available station capacity, namely during the high-flow freshet periods. Stations with no limitations have been excluded.

[1] Ex. F1-1-1, Section 4.3.1, Chart 6.
[2] Reconciling differences may be present due to rounding.

Chart 2 –
Percentage of Time Limited by Available Capacity (Expected)

Generating Station(s)	2026	2027
Abitibi Canyon	3%	3%
Aguasabon	15%	15%
Alexander	0%	5%
Arnprior	8%	2%
Barrett Chute	0%	2%
Calabogie	5%	6%
Cameron Falls	30%[1]	1%
Caribou Falls	0%	53%[2]
Chats Falls	15%	19%
Chenaux	12%	9%
Des Joachims	10%	9%
Kakabeka Falls	100%[3]	94%[3]
Manitou Falls	11%	0%
Mountain Chute	8%	13%
Otter Rapids	10%	9%
Otto Holden	0%	7%
R.H Saunders	4%	2%
Silver Falls	7%	0%
Whitedog Falls	4%	5%
Sir Adam Beck Complex	0%	4%

Notes:
[1] Cameron Falls GS: multiple overlapping unit outages in 2026.
[2] Caribou Falls GS: full station outage in 2027.
[3] Kakabeka Falls GS: station redevelopment 2026-2027.

Board Staff Interrogatory #141

Interrogatory

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

Preamble:

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

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

Question(s):

a) Please confirm that the Water Conditions Variance Account methodology treats Decew Falls 1 and Decew Falls 2 generating stations in the same manner as described for Sir Adam Beck 1 and 2, and the RH Saunders generating stations. The description at Reference 2, page 8, lines 13 to 23 does not identify these two generating stations. If not confirmed, please explain.

b) Please confirm each of the items below, and if not confirmed, please explain each item:
    i. The OEB-approved EB-2013-0321 regulated hydroelectric production forecast, when annualized, such as for the purposes of the Water Conditions Variance Account, is 33.0 TWh. If this is not confirmed, please explain and provide a monthly summary table of monthly production by Region in excel with unrounded data for one year.
    ii. Please confirm that the difference between EB-2013-0321 OEB-approved regulated hydroelectric production forecast, of 33.0 TWh, and the Water Conditions Variance Account forecast production, of 32.432 TWh, is due to

exclusion of the regulated hydroelectric facilities that do not have modelled production forecasts.

c) Please confirm that OPG agrees that the last OEB-approved Regulated Hydroelectric Production forecast is that forecast approved in EB-2013-0321. If not confirmed, please explain. If it is OPG's view that the OEB approved a Regulated Hydroelectric Production forecast for setting base hydroelectric payment amounts since EB-2013-0321, please provide reference to the OEB Decision and Payment Amounts Order that approved that forecast.

d) Please explain the meaning of "the production used in the calculation underpinning the 2026 regulated hydroelectric payment amount" in Reference 6. OEB staff does not understand OPG's use of the words "used" and "underpinning" in the context of EB-2016-0152 and in the context of Reference 2 p. 8 at lines 22 and 23. How does a forecast that "underpins" payment amounts differ from an OEB-approved production forecast? Please elaborate and explain.

e) Please confirm that in each of EB-2013-0321, EB-2016-0152, EB-2018-0243, EB-2020-0290, and EB-2023-0336, OPG proposed, and the OEB approved, the disposition of DVA balances in those proceedings on the basis of a 33.0 TWh annual production forecast for the regulated hydroelectric generating stations.

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

Response

a) Not confirmed. Consistent with all prior OPG payment amount proceedings, the Hydroelectric Water Conditions Variance Account ("WCVA") methodology does not treat DeCew Falls 1 GS and DeCew Falls 2 GS in the same manner as Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, or R.H. Saunders GS. Water supply to Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and R.H. Saunders GS is directly impacted by water conditions in the Niagara and St. Lawrence Rivers. In contrast, DeCew Falls 1 GS and DeCew Falls 2 GS receive water supply through the Welland Ship Canal managed by St. Lawrence Seaway Management Corporation. The volume of water diverted to the DeCew Falls stations is impacted for variety of reasons, such as plant operations, seaway canal maintenance, conveyance capacity restrictions, and natural conditions. The WCVA entries at DeCew Falls 1 GS and DeCew Falls 2 GS are only limited to natural conditions where Lake Erie levels result in lower water diversions to the stations as stated in Ex. H1-1-1, p. 9, footnote 13. The WCVA variance for DeCew Falls 1 GS and DeCew Falls 2 GS is determined as the difference between DeCew Falls 1 GS and DeCew Falls 2 GS production if there were no diversion cuts and actual production, which is different from the WCVA methodology at Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and R.H. Saunders GS.

b)
i) Not confirmed. The OEB-approved EB-2013-0321 regulated hydroelectric production forecast annualized is 33.0 TWh[1]; however, this is not the reference amount approved to be used for the purpose of determining entries into the WCVA.

The current reference amount for the WCVA is 32.432 TWh[2] which is the reference amount that has been approved and utilized in clearances of the WCVA since EB-2016-0152. Refer to Attachment 1, filed in Microsoft Excel format, for a summary table of monthly production by Region.

ii) Confirmed.

c) Confirmed.

d) Pursuant to the EB-2020-0290 Payment Amounts Order, the 2026 production value provided at Reference 6 is derived by taking the average of the 2014/2015 previously regulated hydroelectric production, and the average of the 2014/2015 newly regulated hydroelectric production forecast adjusted for the July 1, 2014 effective date approved by the OEB.[3] This calculation is detailed in Chart 1 below.

[1] EB-2013-0321, Decision with Reasons, November 20, 2014, p. 9.
[2] Pursuant to the EB-2020-0290 Payment Amounts Orders and prior OEB orders, 32.432 TWh is equal to 20.556 TWh for the Previously Regulated Facilities (average of EB-2013-0321 Payment Amounts Order App. A, Table 4, line 1 (col, (a) and (b)) plus 11.876 TWh for the Newly Regulated Facilities (EB-2013-0321 production for the 21 newly regulated facilities subject to the WCVA).
[3] EB-2020-0290, Payment Amounts Order, App. E, Section 2.1.

Chart 1 –
Calculation of Production Underpinning Hydroelectric Payment Amounts[4]

	2014	2015	Average	Calculation
	(a)	(b)	(c)	
Previously Regulated	20.1	21.0	20.6	(c) = [(a)+(b)] / 2
Newly Regulated	5.5	12.5	12.0	(c) = [(a) + (b)]/ 18 X 12
Total			**32.6**	

The reason for the chosen terminology was to emphasize that the forecast was not approved by the OEB for purposes of setting the 2026 hydroelectric payment amount. The forecast was approved in relation to 2014 and 2015, but remains the forecast underpinning the 2026 regulated hydroelectric payment amount.

e) Not confirmed. In EB-2016-0152, an annual production of 30.2 TWh, based on the 2015 actual production, was used to calculate the regulated hydroelectric payment riders (EB-2016-0152, Payment Amounts Order, App. D, Table 1, line 13).

OPG confirms that 33.0 TWh was used as the annual production amount to determine the regulated hydroelectric payment riders in EB-2018-0243, EB-2020-0290, and EB-2023-0336.

f) Refer to Attachment 2, filed in Microsoft Excel format.

[4] OEB approved production values as stated in EB-2013-0321 Payment Amounts Order, App. A, Table 4.

Board Staff Interrogatory #142

Interrogatory

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

Preamble:

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

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

Question(s):

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

Response

a) Refer to Charts 1 and 2 below. During the course of responding to this interrogatory, OPG noted some minor discrepancies with the May, June, and July numbers provided in Ex. E1-2-1, Chart 4. The corrected numbers have been bolded in Chart 1.

Chart 1 – Updated Ex. E1-2-1, Chart 4
HIM Payments in Market Renewal 2025 and 2026 ($M)

	2025 May	2025 Jun	2025 Jul	2025 Aug	2025 Sep	2025 Oct	2025 Nov	2025 Dec	2026 Jan	2026 Feb
DA HIM	2.0	4.0	8.6	8.8	1.8	2.2	3.9	4.3	8.4	8.0
RT HIM	**2.0**	**3.2**	**2.1**	0.1	(0.3)	0.3	0.9	1.7	2.0	0.7
UIB	**(4.7)**	**(0.8)**	(0.6)	(0.1)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)
Net HIM	(0.7)	**6.4**	**10.1**	8.8	1.3	2.4	4.7	5.9	10.4	8.6

Chart 2 – Updated Ex. E1-2-1, Chart 7
OPG Regulated Hydroelectric MWPs 2025 and 2026 ($M)

	2025 May	2025 Jun	2025 Jul	2025 Aug	2025 Sep	2025 Oct	2025 Nov	2025 Dec	2026 Jan	2026 Feb
RT Energy MWP	0.8	2.2	2.6	0.5	0.2	0.3	0.7	1.2	2.9	4.0
RT OR MWP	1.8	3.2	2.3	0.5	0.5	0.7	1.9	0.8	5.6	1.9
DA Energy MWP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.5
DA OR MWP	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.1
Total MWP	**2.7**	**5.5**	**5.0**	**1.0**	**0.7**	**1.1**	**2.8**	**2.0**	**6.8**	**7.5**

OPG notes that the Renewed Market is yet to complete a full year of operation and the IESO is still undertaking efforts to calibrate and correct certain market aspects that may affect both HIM revenues and MWPs. For example, the IESO recently approved a Market Rule amendment package (MR-00490-R00)[1] to address unwarranted Make-Whole Payments. OPG believes additional time is required to establish a consistent baseline of market operations and that some of the observed volatility in these revenues is expected to subside.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2026/MR-00490-R00-Adjustments-RTMWPs.pdf

Board Staff Interrogatory #143

Interrogatory

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

Preamble:

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

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

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

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

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

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

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

Question(s):

a) Is OPG requesting approval of all five years for which HIM revenues have been forecast in the application?

b) Does singling out 2027, in proposing to "Establish a HIM forecast for 2027", mean OPG is proposing to establish a new HIM "threshold" based on the forecast of $17.8 million for 2027?

c) If OPG is not seeking approval of the HIM revenues that have been forecast for the five years of the IR term or a change to the HIM threshold, please clarify what OPG is proposing, as OEB staff was unable to locate a reference to HIM forecast in the list of requested approvals quoted above or in the "Approvals" section of the application.

d) Please explain the methodology used by OPG to arrive at $17.8 million for 2027. Please also explain how OPG arrive at the forecast HIM revenues for the subsequent years in the IR term (if the approach differed).

Response

a) No. In the course of preparing this response, OPG discovered it inadvertently provided columns d)-k) for lines 15-21 in Ex. G1-1-2, Table 1. As described in part c), OPG is only seeking approval of the 2027 revenue requirement for the regulated hydroelectric facilities and therefore only the 2027 HIM revenue forecast is relevant. OPG will update the evidence to remove this information from the Application.

b) No, OPG is not proposing to establish a new HIM "threshold". As described in Ex. G1-1-1, Section 7.0, and Ex. E1-2-1, Section 5.6, OPG is proposing to eliminate the sharing of HIM net revenues that exceed the HIM revenue forecast. Consistent with the proposal to retain 100% of actual HIM revenue, OPG is proposing to terminate the Hydroelectric Incentive Mechanism Variance Account as of the effective date of the payment amounts order in this proceeding, per Ex. H1-1-1, Section 5.3. As such, establishing a HIM "threshold" would no longer be applicable or required.

c) As described in Ex. G1-1-1, Section 7.0 and Ex. E1-2-1, Section 5.6, OPG proposes to use 50% of the 2027 HIM revenue forecast of $17.8M, that is $8.9M, as an offset to the 2027 revenue requirement used in setting OPG's regulated hydroelectric payment amount for the test year. This proposed offset is reflected in OPG's proposed 2027 revenue requirement for the regulated hydroelectric facilities as presented in Ex. A1-2-2, Section 1. As described in part b), there is no longer a need for a HIM threshold under OPG's proposal.

d) The methodology used to forecast the HIM revenue in this Application is detailed in Ex. G1-1-1, Section 7.0.

Board Staff Interrogatory #144

Interrogatory

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

Preamble:

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

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

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

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

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

Question(s):

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

b) Please also explain why OPG did not reference the HIM revenue sharing in providing reasons to the MSP in relation to reduced time-shifting of production (including and excluding the PGS).

c) Given that OPG proposes to eliminate HIM revenue sharing for all of its prescribed hydroelectric facilities, has OPG conducted analysis, similar to that summarized in Reference 4 regarding the PGS, to identify the effect of HIM sharing on its ability to time-shift water at its regulated facilities other than the PGS?

Response

a) OPG's presentation to the MSP in advance of the publication of the MSP Monitoring Report 32 is provided in EB-2020-0290, Ex. L-A1-11-OSEA-002, Attachment 1. HIM revenue sharing alternatives were not contemplated as part of these discussions, which took place while OPG was still assessing the anticipated impact of the IESO's Market Renewal Program (MRP) and developing strategies to address MRP related changes. OPG's rationale for the removal of HIM revenue sharing aligns with the MSP's recommendations, as it addresses the adverse impacts on time-shifting when OPG's HIM revenues exceed the applicable threshold.

b) OPG did not raise revenue sharing above the HIM threshold as an explanation, because OPG's actual HIM revenues during the years referenced by the MSP were well below the HIM threshold and therefore sharing did not have an impact on OPG's operational decision-making regarding the HIM. As described in EB-2020-0290, Ex. L-A1-11-OSEA-002, OPG agreed with the MSP's list of factors that affected the time-shifting at the PGS. OPG presented an alternate view with respect to the MSP's assertions by stating that time-shifting at OPG's other (i.e., non-PGS) hydroelectric resources had changed in response to different annual flows.

c) No.

Board Staff Interrogatory #145

Interrogatory

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

Preamble:

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

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

Question(s):

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

Response

a) The modelling framework used for Options 1 and 2 is not applicable to Option 3. Options 1 and 2 compare the impact of changing certain inputs to the offer equations for the PGS and would apply across all HIM revenues. Option 3 (which looks at elimination of HIM sharing above a threshold) only impacts PGS offer behaviour when OPG's HIM revenues exceed the forecast. This fundamental distinction prevents OPG from using the same modeling framework used in Options 1 and 2.

OPG assessed the potential benefit to ratepayers of time-shifting water under Option 3 by comparing (i) the PGS price spread when OPG shares 50 percent of its revenues, to (ii) the PGS price spread when OPG retains all such revenues in select instances when OPG's actual HIM revenues exceed its forecast. Based on this analysis, OPG determined that when it is required to share 50 percent of the revenues above the HIM forecast, the applicable price spread will be notably higher. A higher price spread inhibits PGS utilization and, as demonstrated in Options 1 and 2, increased utilization of the PGS is associated with greater customer benefits. Accordingly, the directionality of this relationship, combined with the reduction in price spreads when OPG retains all HIM revenues, demonstrates the benefits of Option 3 and supports OPG's proposal to eliminate HIM sharing.

Board Staff Interrogatory #146

Interrogatory

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

Preamble:

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

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

Question(s):

a) Of the three options that OPG assessed, please identify which option would provide OPG with the greatest incentive to time-shift production and please explain why.

b) Given the relative size of the transmission NSC versus the IESO Fee, would changing the designation of the PGS to an energy storage facility essentially result in the implementation of Option 1 since both would result in an exemption from the NSC?

c) If the designation of the PGS was changed to an energy storage facility, would there still be a material incremental incentive for OPG to time-shift production if HIM revenue sharing above the threshold was also eliminated? If so, please explain how material the incremental incentive would be.

d) Since the MSP based their analysis and recommendation discussed in the Application on the PGS being designated as a generation facility, does OPG believe the MSP's assessment would still be applicable if the PGS becomes an energy storage facility?

e) Please clarify when, in 2026, OPG expects to make a decision related to the designation of the PGS. Please also explain why OPG did not make that decision before the Application was submitted.

Response

a) OPG's analysis demonstrates that the removal of PGS load charges (Option 1) would provide a greater incentive for OPG to time shift water than the removal of PGS gross revenue charge ("GRC") (Option 2). Option 1 provides a greater incentive because the removal of load charges, and particularly the Network Service Rate Charge ("NSC"), decrease the spread required to economically cycle the PGS by a greater magnitude than removing PGS GRC. Removing PGS load charges also has the added benefit of enabling the PGS to pump in all hours of the day, which would increase OPG's opportunities to utilize the PGS but cannot easily be expressed in terms of price spread. This is demonstrated by the incremental PGS utilization, which is higher in Option 1 when compared to Option 2.[1]

Furthermore, in a scenario where the HIM threshold has been exceeded, OPG has also concluded that eliminating HIM revenue sharing above the threshold (Option #3) provides a greater incentive to time shift water than removal of PGS load charges.[2] As described in Ex. L-E1-Staff-145, part a), OPG's modeling framework does not allow for a like for like comparison of Options 1 and 2 with Option 3. As a result, OPG cannot conclude which option provides a greater incentive.

b) Yes, given the relative size of the transmission NSC versus the IESO Fee, changing the designation of the PGS to an energy storage facility would essentially result in the implementation of Option 1 since both would result in an exemption from the NSC.

c) Yes, if the designation of the PGS was changed to an energy storage facility, further eliminating the HIM revenue sharing above the threshold would provide an additional incentive for OPG to time shift by avoiding increasing the price spread due to sharing when OPG's revenues exceed the threshold.

1 Ex. E1-2-1 Attachment 1, Chart 2.0 and 4.0
2 Ex. E1-2-1 Attachment 1, Chart 9.0 shows a $6.70 ($14.90 - $8.20) spread increase required for economic PGS cycling under a HIM revenue sharing scenario, while OPG calculates the removal of load charges would only decrease the economic spread by $1.37.

As explained in Ex. L-E1-Staff-145, OPG cannot conclude on “how material” the incentive might be under the stated conditions. It is only able to conclude that OPG’s incentive to time shift water increases along with the opportunity to earn and retain HIM revenues.

d) Yes, OPG believes the MSP’s assessment would still be applicable if the PGS becomes an energy storage facility. The incentive to OPG in all market conditions provided by the elimination of HIM revenue sharing exists regardless of the designation of the PGS as it reduces the required economic price spread to utilize the PGS.[3]

e) On March 31, 2026, the OEB issued its decision for the Generic Hearing on Uniform Transmission Rates.[4] In its decision where the OEB approved the definition of an Electricity Storage Facility, it also confirmed that the technology neutral definition includes OPG’s Sir Adam Beck Pump Generation Storage facility, while acknowledging that the facility forms part of OPG’s generation facilities and is licensed as such. With the understanding that there is no requirement for the PGS to be re-licensed as an Electricity Storage Facility in order for it to meet its definition, OPG does not believe any further decisions are required regarding the designation of the PGS. At the time of this Application’s filing, as OPG had not received this confirmation from the OEB, it had not made a decision on the designation of the PGS given the possible regulatory implications that were yet to be fully contemplated.

[3] Ex. E1-2-1 Attachment 1, Chart 9.0.
[4] EB-2022-0325, Decision and Rate Order, March 31, 2026.

Board Staff Interrogatory #147

Interrogatory

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

Preamble:

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

Question(s):

a) Please elaborate on a “flatter scheduling profile”. For example, does that mean no time-shifting of hydroelectric resources (e.g., Pump-Generating Station (PGS) operated like baseload)?

b) Please provide a table that sets out the underlying assumptions that were used to complete Chart 6 (separately for 2026 and 2027) including the following: $/MWh and MWh (for OPG generation, non-OPG generation and imports), the amount of Surplus Baseload Generation (SBG)-related Generation Curtailment, the Real-Time Ontario Zonal Price (OZP) and Day-Ahead OZP, economic time-shifting (MWh), HIM-driven incremental time-shifting (MWh), etc.

Response

a) The “flatter scheduling profile” case used in the HIM customer benefit analysis represents a generation profile where, absent an incentive, OPG does not time-shift to the same extent as in the “time-shifting hydroelectric resources” case. In the “flatter scheduling profile”:
    - Available unit hours of water are allocated to units in a way that minimizes starts and stops while respecting good utility practice and efficient unit operation. This approach produces a shaped (i.e., non-flat) profile based on unit water availability.

- PGS is not utilized to time shift water.

In all other aspects, the two cases have identical inputs. Additional details on the HIM customer benefit analysis can be found in OPG's response to Ex. L-M-SEC-10 in EB-2023-0336.

b) The customer benefits in Chart 6 are presented as changes in customer costs between a "time-shifting hydroelectric resources" and a "flatter scheduling profile" scenario. The requested "underlying assumptions that were used to complete Chart 6" are outputs of OPG's model, expressed as changes between the two scenarios in Chart 1 below. A general description of OPG's proprietary model used to analyze the customer benefit, including input assumptions and methodology, is discussed in Ex. L-E1-SEC-132. Additional data requested that is not found in Ex. L-E1-SEC-132 can be found in Chart 1 below.

Chart 1
Modelling Analysis Outputs Underpinning the HIM Customer Benefit

		2026	**2027**
Change in OPG Regulated Generation (net of spill)	TWh	0.09	0.01
Change in All Other Generation (net of spill)	TWh	(0.35)	0.21
Change in Imports into Ontario	TWh	0.07	(0.17)
Change in Surplus Baseload Generation Curtailment	TWh	(0.13)	(0.03)
HIM-Driven Incremental Time-Shifting	TWh	2.49	2.34
Change in OPG Generation Cost	$/MWh	0.16	0.48
Change in Non-OPG Generation + Imports Cost	$/MWh	(0.13)	(1.34)

OPG does not understand the meaning of "economic time-shifting" and therefore has not included this item in the chart.

Board Staff Interrogatory #148

Interrogatory

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

Preamble:

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

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

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

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

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

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

Question(s):

a) As OPG noted, it is unable to "accurately" distinguish between spill due to global and local SBG conditions. Please describe if OPG assessed any options to provide a "rough" estimate of local spill. If so, please explain those options and why they were considered not to be appropriate by OPG. If OPG did not undertake this type of assessment, please explain why.

b) Is there any difference between OPG receiving a CMSC payment due to a transmission constraint (in the Legacy Market) and OPG receiving a payment for local spill (in the Renewed Market), aside from the payment being based on the difference between the market price and accepted offer (CMSC payments) and the regulated hydroelectric payment amount (Local Spill)? Please explain.

c) Please provide a table that includes, for the most recent five years of the Legacy Market, the annual amounts that OPG received from the IESO in CMSC payments and the annual amounts that OPG booked to the SBGVA.

d) Please elaborate on "SBG conditions are generally expected to be present when … real-time LMP for a given resource falls below its … GRC price threshold". In doing so, please reflect the following:
   i. Please confirm that is the expectation because the GRC represents the minimum offer price that would allow OPG to recover its cost of production associated with the applicable regulated generation facility.
   ii. Please also confirm "SBG conditions" in the excerpt above would indicate "Local" SBG. If so, please explain why this could not be used as a basis to estimate Local SBG. If not, please explain how it could indicate only "Global" SBG.

e) Please identify if OPG has investigated with the IESO the possibility of using metering to detect Local vs. Global SBG. If OPG has done so, please explain the results of those discussions. If not, please explain why.

Response

a) In considering options for revising the SBGVA, OPG was unable to distinguish between spill due to global and local SBG conditions as discussed previously in OPG's interrogatory response in EB-2023-0336, Ex. L-M-ED-10. OPG's inability to develop an alternative process to simulate the HOEP-based global spill in the Legacy Market precludes the computation of a "rough" estimate in the Renewed Market. Without a reliable basis to isolate the impacts of global versus local spill in the Renewed Market, a rough forecast estimate would not be meaningful in this context. Any estimate produced without that foundation would be speculative and would not support accurate tracking or recording of amounts in SBGVA.

b) Yes, there are potential differences between OPG receiving a CMSC payment due to a transmission constraint (in the Legacy Market) and OPG receiving a payment for local spill (in the Renewed Market) beyond the applicable pricing. While OPG agrees that in the context of transmission constraints the two concepts are related, the Legacy Market's use of two schedules and its optimization engine are fundamentally different than the single schedule market and the new dispatch scheduling engine used in the Renewed Market. Additionally, CMSCs are calculated based on the difference between the unconstrained and constrained schedules without any consideration to spill whereas the local SBG spill payment is strictly related to OPG incurring actual spill under local SBG conditions. As such, under identical market conditions, it is not necessarily the case that a CMSC in the Legacy Market would map to an instance of local SBG-related spill in the Renewed Market.

c) Chart 1 below displays annual CMSC payments received by OPG and annual amounts recorded in the SBGVA.

Chart 1
CMSC Payment Received & Amounts Recorded in SBGVA ($M)

	2020	2021	2022	2023	2024	2025 (Jan-Apr)
CMSC payments received[1]	18.4	36.2	115.0	31.2	27.8	12.8
Amount recorded in SBGVA	130.4	56.4	47.9	29.9	10.6	5.9

d) OPG confirms that GRC represents the minimum offer price that would allow OPG to recover its cost of production associated with the applicable regulated generation facility, making GRC the appropriate threshold.

As described in part b), and consistent with the IESO's definitions of local and global SBG, in the Renewed Market, global SBG (in the context of its meaning under the Legacy Market[2]) may occur simultaneously with local SBG and the two are not accurately distinguishable in the Renewed Market. As described in Ex. L-E1-IESO-001 part 2) OPG believes that the LMP in relation to OPG's GRC is an appropriate indication of SBG conditions, be it local, global or local and global occurring simultaneously.

As such, OPG cannot confirm that SBG conditions indicate exclusively local or global SBG. As explained in part a), OPG does not have the ability to measure or estimate local vs. global SBG as local SBG events would at times occur coincident with global SBG conditions.

e) OPG has not investigated the possibility of using metering to detect Local vs. Global SBG with the IESO. The presence of SBG conditions indicate the relationship between demand and the offered supply of baseload generation. Metering in relation to after-the-fact measurement of supply and demand (e.g., via revenue meters) would already include actions taken in response to IESO's management of SBG conditions. As described in Ex. L-E1-IESO-001 part 2), OPG believes that the LMP in relation to OPG's GRC is an appropriate indication of SBG conditions in the Renewed Market.

[1] Values include only CMSC payments received for energy and exclude any CMSC payments received for operating reserve.
[2] IESO, Renewable Integration Stakeholder Engagement 91, Minutes of Meeting, March 2, 20211 *"The IESO defines global SBG as absent any transmission limitations the province has too much baseload generation to meet Ontario demand."*

Board Staff Interrogatory #149

Interrogatory

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

Preamble:

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

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

Question(s):

a) Has OPG done historic analysis related to breaking down the volume of spill due to the four factors – water conveyance constraints, production capability, market constraints and contractual obligations? If so, please provide the results in a table for the years that OPG completed that analysis.

b) Please confirm that, if the volume of spill associated with "market constraints", could be calculated, it would be equal to the volume of what is termed "local" spill in the Application. If that is not the case, please explain the difference.

c) Please explain if there is a difference between foregone production due to "market" constraints and "transmission" constraints (i.e., unable to get output offered to where demand is due to transmission system). If there is a difference, please explain the other types of constraints included in market constraints (including how there is no relationship to the transmission system) and please also clarify the materiality of constraints that are not related to transmission.

d) Please comment on whether the change in approach under the Renewed Market calculation – where spill associated with market constraints is included in the SBGVA rather than subtracted (as it was under the Legacy Market calculation) – affects the level of SBG-related compensation to OPG relative to Legacy Market years. If OPG does not believe this change methodology leads to over compensation, please explain why.

Response

a) OPG completed a historical analysis to break down the volume of spill due to the four factors, which has been summarized in Chart 1 below.

Chart 1 - Historical Spill Amounts by Category [TWh]

	2019	2020	2021	2022	2023
Water conveyance constraints	2.1	2.8	1.2	0.9	0.9
Production capability	5.5	3.5	1.9	3.3	2.6
Market constraints	1.0	1.2	1.3	2.0	1.4
Contractual obligations	0.2	0.2	0.2	0.2	0.2

b) The volume of what is termed “local” spill (i.e., forgone generation in the form of hydroelectric spill as a result of local SBG conditions) is a construct of the Renewed Market. In contrast, spill associated with “market constraints” refers to a Legacy Market comparison of its two schedules (when the constrained schedule is lower than the unconstrained schedule) and the presence of coincident spill. If the Legacy Market ran in parallel with the Renewed Market allowing for the continuation of such computation, OPG expects a meaningful overlap of instances when it experiences “local” SBG spill and the presence of “market constraints”. However, given the multitude of sources of differences between the unconstrained and constrained run, OPG does not believe that the two volume amounts will be equal.

c) In the context of the Legacy Market and the “market constraints” terms as described in part b) above, OPG believes that forgone production (i.e., spill) due to “transmission” limitations would comprise a significant portion of spill identified as coincident with “market constraints”. However, OPG acknowledges possible instances when non-transmission related differences between the unconstrained and constrained schedules occur concurrently with spill. OPG does not have visibility into the IESO’s optimization engine for the Legacy Market and can only conceptually identify certain known differences between the two runs of the engine. A non-exhaustive list of such examples include different ramp rates, the utilization of Multi-Interval Optimization and the joint optimization of Energy and Operating Reserve. While not able to comment on the precise impact, OPG believes there is significant overlap between spill as a result of transmission constraints and coincident with market constraints.

d) As stated in Ex. E1-2-1, in the Legacy Market the SBGVA recovered forgone generation in the form of hydroelectric spill due to Global SBG conditions whereas in the new market the SBGVA cannot distinguish between Global and Local SBG conditions and is expanded to include both. OPG is unable to assess the specific impact of the change in methodology as the relative magnitude of local and global SBG recorded in the SBGVA cannot be measured, as explained in Ex. L-E1-Staff-148 part a). Of note, because of a multitude of market factors, OPG forecasts significant reductions in SBG-related compensation throughout the IR term relative to Legacy Market years.[1]

OPG does not believe this change in methodology leads to over-compensation for the following reasons:

- There are no reductions to the production forecast for forgone production expected to be recorded in the SBGVA;
- OPG will recover amounts associated with Global and Local SBG in the SBGVA at the regulated payment amount less applicable gross revenue charge; and any Make-Whole Payments received for forgone production that is recorded in the SBGVA will be credit back to ratepayers through the SBGVA.

[1] Ex. E1-2-1 Attachment 1, page 8, Figure 1.0

Board Staff Interrogatory #150

Interrogatory

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

Preamble:

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

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

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

Question(s):

a) Is the "originating hour" the hour when the SBG event began? If so, why would the "previous" hour be considered an SBG hour and the appropriate hour for the SBGVA entry?

b) Given the Legacy Market was a real-time market and the underlying intent of the SBGVA is to compensate OPG for forgone production where OPG needs to spill water (rather than produce energy) in the applicable hours, please explain why the hour associated with the SBGVA entry is the "previous hour" rather than the same hour as the hour where OPG's algorithm is "quantifying SBG spill in hours when HOEP is less than the applicable GRC".

c) Please modify Attachment 4 (i.e., Reference 2) by adding a column that includes the HOEP for the "previous" hour.

Response

a) As discussed in EB-2023-0336, Ex. L-H-SEC-05, "previous SBG hour" and "originating SBG hour" refer to the same hour, namely an hour preceding (e.g., earlier in the day) the hour when spill is booked into the SBGVA. In such "originating SBG hour", while SBG conditions are present causing a resource to forgo generation, instead of being spilled, water is stored based on storage availability. The hour when SBG is booked into the SBGVA is an hour following this "originating SBG hour", when the water previously stored because of prior SBG conditions is spilled.

b) As explained in a), during an SBG hour (i.e., any hour where HOEP/LMP ≤ GRC), OPG stores as much water as possible before spilling. OPG's spill algorithm accounts for the fact that water stored during an SBG hour may be forced to be spilled later in the day, in an hour when the HOEP has risen above GRC. In these instances, if the spill did not originate for any other identifiable reason, the spill tool records that spill as SBG to the extent that the resource had available capacity during SBG hours earlier in the day but was storing water instead of generating or spilling it.

c) Refer to Attachment 1, filed in Microsoft Excel format.

Board Staff Interrogatory #151

Interrogatory

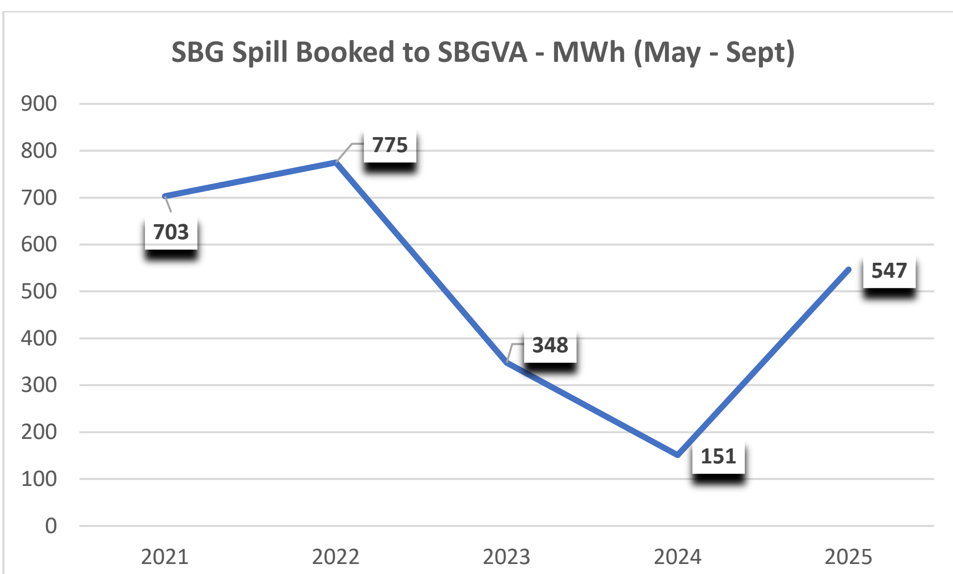
Reference:
Ref 1: Exhibit E1 / Tab 2 / Schedule 1 / pp. 7-8
Ref 2: Exhibit E1 / Tab 2 / Schedule 1 / Chart 2

Preamble:

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

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

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



Question(s):

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

Response

a) Forgone production due to SBG was 0.4 TWh higher in Q2 2025 compared to the same quarter in 2024, driven by a stronger and longer freshet across the province and lower net demand on the system. Most forgone production due to SBG occurs during the spring freshet period, usually April, May and June, and the timing, duration and magnitude of the spring freshet is usually the most significant driver of the total SBG spill in any given year. SBG spill at Sir Adam Beck generating stations (which is first in the GRC based spill order) was 0.2 TWh higher in May 2025 compared to May 2024, with instances where the market price (LMP in 2025 and HOEP in 2024) dropped below the applicable GRC of $14.40/MWh in 58% of hours in May 2025 compared to only 12% in May 2024.

   OPG confirms that all forgone production recorded in the Hydroelectric Surplus Baseload Generation Variance Account (SBGVA), including amounts booked in 2025, is the result of actual spill. As such, the increase from 2024 to 2025 is a result of the respective SBGVA spill algorithm attributing four times as much actual spill to SBG conditions, as defined in each algorithm, year over year. OPG is unable to assess the impact of the change in such methodology as the relative magnitude of local and global SBG recorded in the SBGVA cannot be measured, as explained in Ex. L-E1-Staff-148 a).

Board Staff Interrogatory #152

Interrogatory

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

Preamble:

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

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

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

Question(s):

a) Given "all" Energy Make Whole Payments (MWPs) would include Real-Time (RT) Energy MWPs, please clarify what OPG is proposing in stating "retain" RT Energy MWPs in the first reference and "forgo" them in the second reference above.

b) Please clarify the "assumption" that OPG will "receive OR MWPs" within the context of OPG receiving approval to retain only RT Energy MWPs (and OPG proposing to continue that in this Application).

Response

a) As described in Ex. E1-2-1, Section 4.3, corrected on March 10, 2026, OPG is proposing to retain Real-Time Energy MWPs, while forgoing to receive both Day-Ahead Energy MWPs and Day-Ahead OR MWPs.

b) As the OEB only prescribes OPG's payment amounts related to output (energy) and not operating reserve, OPG expects to continue receiving RT OR MWPs. These RT OR MWP will continue to be subject to the Ancillary Services Net Revenue Variance Account. As stated in part a) above and further described in Ex.

E1-2-1, Section 4.3, OPG accepts forgoing Day-Ahead OR MWPs based on low materiality and IESO settlement considerations.

CCC Interrogatory #065

Interrogatory

Reference:
Exhibit E2, Tab 1, Schedule 1, p. 4

Preamble:

Concurrently, during the same Unit 2 Darlington PMS replacement outage in 2027, OPG will execute the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project that was deferred from 2025 to support grid reliability and manage resource constraints during concurrent nuclear outages.

Question(s):

a) At Exhibit 2, Tab 1, Schedule 2, p. 2, OPG notes that the total outage related to the PMS and Turbine Control and Auxiliary Systems upgrade project for Unit 2 in 2027 is 316.5 days, and includes the outage related to the VBO for unit 2. How long would the outage be if only the PMS and the VBO were being conducted in 2027, had the Turbine Control and Auxiliary Systems upgrade project been completed in 2025 as originally planned?

b) What was the incremental net revenue earned by OPG as a result of avoiding the planned Turbine Control and Auxiliary Systems upgrade project in 2025?

Response

a) The Unit 2 planned outage in 2027 would be 15 days shorter if it did not include the Turbine Control and Auxiliary Systems Upgrade (“TG Controls”) project. The Unit 2 planned outage duration in 2027 is 366.3 days (and not 316.5 days, as specified in the preamble to the question[1]) and would have been 351.3 days if the TG Controls project had been completed in 2025 as originally planned. As specified in Ex. L-E2-Staff-159 and Ex. L-D2-Staff-082, Attachment 1, the TG Controls project will be largely executed in parallel with PMS Replacements, except for the final 15 days of the outage where the TG Controls undergo dynamic high-power testing and commissioning.

[1] The 316.5 days represents incremental planned outage days in 2027 compared to the 2026 OEB-Approved production plan, as indicated in Ex. E2-1-2, p. 2, lines 18-23.

For clarity, the Unit 2 planned outage duration in 2027 does not include the Darlington vacuum building outage ("VBO") as specified in the preamble. The VBO is planned for 45.9 days per unit (i.e., 137.7 days total for all the other 3 units) and the VBO work for Unit 2 is scheduled concurrently with the planned PMS replacement outage and thus the Unit 2 planned outage duration is not impacted by the VBO.

The incremental net revenue impact associated with deferring the TG Controls project from 2025 to support grid reliability and manage resource constraints during concurrent nuclear outages is $179.5M, net of fuel costs.

OAPPA Interrogatory #010

Interrogatory

Reference:
Exhibit E2 / Tab 1 / Schedule 2 / Table 1b

Question(s):

a) Please explain how the Unit Capability Factor relates to the annual production of TWh.
b) Does a change in the Unit Capability Factor change the (annual) production forecast?
c) Assuming a change in the Unit Capability Factor changes the (annual) production forecast, please provide a table, reflecting the corresponding change in production for each of the 2027-2031 years under the following change to the Unit Capability Factors:
    i. +/- 0.5 %
    ii. +/- 0.75 %
    iii. +/- 1.0 %
    iv. +/- 1.35 %
    v. +/- 1.75 %
d) Please explain how the Unit Capability Rate (or also “Capacity Factor”) does, or does not, relate to, or factors into the annual production estimates.
e) What is the formulaic difference (i.e. calculation details) between Unit Capability Factor and Unit Capability Rate (Capacity Factor)?

Response

a) Unit Capability Factor (“UCF”) is the percentage of maximum energy generation that a unit is capable of supplying to the electrical grid, limited only by factors within the control of plant management, as defined in Ex. E2-1-1, Attachment 1. Therefore, a higher UCF will result in higher annual production of TWh and vice versa.

b) Yes. A change in UCF will change the annual production forecast.

c) Attachment 1 provides the production impacts resulting from the requested changes in UCF, which are provided for illustrative purposes only. The actual production impacts may differ depending on the timing of production forecast assumptions within the year.

d) Unit Capability Rate ("UCR") is the ratio of the available energy generation over a given time period to the reference energy generation over the same time period but not counting planned energy losses in the denominator, as defined in Ex. E2-1-1, Attachment 1. Therefore, as with UCF, a higher UCR will result in higher annual production of TWh and vice versa.

e) UCF is calculated as follows:

$$UCF = \frac{REG - PEL - FEL - OEL}{REG} \, x \, 100, \%$$

Where REG = reference energy generation for the period
PEL = total planned energy losses for the period (e.g., planned outages)
FEL = unplanned forced energy losses for the period (e.g., FLR)
OEL= unplanned outage energy losses for the period

UCR is calculated as follows:

$$UCR = \frac{REG - PEL - FEL - OEL}{REG - PEL} * 100$$

The only difference between the metrics is that UCR adjusts for the impact of planned energy losses in the denominator.

Attachment 1

	Darlington Production Impact (TWh) *					Pickering Production Impact (TWh)					DNNP Production Impact (TWh)				
UCF (%)	2027	2028	2029	2030	2031	2027	2028	2029	2030	2031	2027	2028	2029	2030	2031
±0.50	±0.15	±0.15	±0.15	±0.15	±0.15	-	-	-	-	±0.015	-	-	-	±0.003	±0.014
±0.75	±0.23	±0.23	±0.23	±0.23	±0.23	-	-	-	-	±0.023	-	-	-	±0.004	±0.021
±1.00	±0.31	±0.31	±0.31	±0.31	±0.31	-	-	-	-	±0.030	-	-	-	±0.006	±0.027
±1.35	±0.42	±0.42	±0.42	±0.42	±0.42	-	-	-	-	±0.041	-	-	-	±0.008	±0.037
±1.75	±0.54	±0.54	±0.54	±0.54	±0.54	-	-	-	-	±0.053	-	-	-	±0.010	±0.048

OAPPA Interrogatory #011

Interrogatory

Reference:
Exhibit E2 / Tab 1 / Schedule 1 / Page 11 - 13

Preamble:

"In planning for the VBO, OPG has reviewed lessons learned and benchmarked other utilities. In addition, OPG is utilizing innovative technology and drones to perform some of the vacuum building inspection work and planning to initiate projects that would provide opportunities in future VBO's. OPG's generation forecast reflects a planned duration of 45.9 days to execute the VBO".

Question(s):

a) Please confirm that the Pickering VBO in 2022 lasted 30 days, 12 days ahead of schedule.
b) What were the major contributors to the accelerated VBO scheduling at Pickering?
c) Please identify any major differences of the 2022 Pickering VBO's planned activities versus those planned for Darlington's VBO in 2027.
d) Please confirm the planned duration of the key Emergency Coolant Injection valve replacements project(s), planned concurrently with the VBO.
e) If the Emergency Coolant Injection valves cannot be completed within the VBO timeframe, what other planned outages, if any, could these valves be replaced concurrently with?
f) Bruce's VBO in April 2024 appears to have only taken 16 days (as based on publicly available generation production data from the IESO), 9 days faster than its planned 25 days. Is OPG aware of any major planned activity differences to its Darlington VBO in 2027 and if so, what are those? Has OPG been able to incorporate any of the lessons learned from the Bruce VBO experience and if so, what were those?

Response

a) Not confirmed, the Pickering VBO duration in 2022 was 28 days (i.e., last unit off to first unit on), which was two days ahead of schedule.
b) The major contributors to reducing the 2022 Pickering VBO duration, which have been applied to the 2027 Darlington VBO, as applicable, involved scoping decisions, resourcing strategies and achieving efficiencies, including:
    - Pressure relief duct entries supporting online inspections for accessible items typically inspected in a VBO.

- Use of technology (e.g., drones) to perform periodic inspection programs, which reduce requirements for scaffold builds (refer to Ex. L-E2-SEC-140 for additional information).
- Use of thermal (battery powered) clothing to extend working time in colder weather.
- De-scoping life extending modifications with Pickering shutdown then anticipated by September 2026.
- Rope access, a first-of-its-kind access method for non-destructive testing, was used for inspections and repairs.

c) The major difference from the 2022 Pickering VBO versus the 2027 Darlington VBO is that Darlington's outage requires certain scope for long-term sustaining work that Pickering's did not. For the Darlington VBO, such scope includes replacement and overhaul of 33 Emergency Coolant Injection ("ECI") valves and another 118 replacement and overhauls of Low-Pressure Service Water ("LPSW"), Emergency Service Water ("ESW") and Negative Pressure Containment ("NPC") system valves and piping.

d) The planned duration for the key ECI valve replacements during the Darlington VBO is 15 days.

e) ECI valve replacements must be completed during the Darlington VBO as all units must be shut down in order to perform this work. There is no other individual planned outage condition where this work can be completed.

f) OPG has benchmarked Bruce Power's recent VBO and understands the main differences in outage scope complexity to be that the following items are required to be in scope for the Darlington VBO but were excluded from the Bruce VBO scope:
   1. Replacement of ECI valves.
   2. Replacement and overhaul ESW, LPSW and NPC valves and piping.
   3. Performing First-of-a-Kind electrical bus maintenance during the VBO.
   4. Post Accident Water Cooling System piping replacement.

   While OPG benchmarked Bruce Power to inform its own VBO work where appropriate, OPG acknowledges that certain differences may exist that make direct comparison between stations complex. Without considering things like design differences, equipment reliability requirements, or licensing obligations, comparisons of scope and/or duration may not be salient as they would not account for things like VBO frequency or the need for additional mid-cycle station containment outages.

Despite these nuances, OPG has incorporated lessons learned from the Bruce VBO into Darlington VBO plans, including the following:

- Some electrical bus maintenance will now be completed online.
- Several inspections have been completed online.
- Unit rundown strategy incorporates rundown efficiencies.
- Replacement of some Auxiliary Service Water valves online.

SEC Interrogatory #137

Interrogatory

Reference:
E2
EB-2020-0290, E2-01-CCC-43

Question(s):

Please expand E2-01-CCC-43 Attachment 1 and Attachment 2 (EB-2020-0290) to include 2021-2026 approved and actual/budgets, as well as 2027-2031 forecast amounts.

Response

Refer to Attachment 1.

Numbers may not add due to rounding

Chart 1 - Outage Days Metrics 2008-2031 By Nuclear Unit

	Actuals																		Forecast[8]					
Operating Unit	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 [11]**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Darlington Unit 1																								
PO Days (excludes Refurb)	69.1	30.1	0.0	55.4	0.0	0.0	75.3	47.4	0.0	98.8	0.0	0.0	0.0	77.9	0.0	0.0	0.0	21.7	0.0	60.9	120.2	0.0	15.0	124.2
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	4.9	0.0	0.0	2.1	24.5	0.0	12.1	2.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Total	69.1	30.1	0.0	60.3	0.0	0.0	77.4	73.7	0.0	110.9	4.8	0.0	0.0	77.9	0.0	0.0	0.0	22.9	0.0	60.9	120.2	0.0	15.0	124.2
Darlington Unit 2																								
PO Days (excludes Refurb)	0.0	32.0	61.7	0.0	0.0	77.9	0.0	50.3	0.0	0.0	0.0	0.0	0.0	0.0	45.1	0.0	86.5	0.0		360.0	6.3	15.0	124.2	0.0
FEPO Days	0.0	3.2	0.0	0.0	0.0	19.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.0	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	35.2	61.7	0.0	0.0	97.6	2.8	50.3	2.8	0.0	0.0	0.0	0.0	0.0	45.1	0.0	92.0	0.0	0.0	360.0	6.3	15.0	124.2	0.0
Darlington Unit 3																								
PO Days (excludes Refurb)	0.0	79.5	0.0	0.0	56.2	0.0	0.0	95.8	19.6	0.0	82.7	0.0	33.0	0.0	0.0	0.0	0.0	0.0	266.7	45.9	15.0	124.2	0.0	15.0
FEPO Days	0.0	7.7	0.0	0.0	0.0	0.0	0.0	5.8	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	4.9	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	87.2	4.9	0.0	56.8	0.0	0.0	101.6	19.6	0.0	82.7	0.0	34.3	0.0	0.0	0.0	7.1	0.0	266.7	45.9	15.0	124.2	0.0	15.0
Darlington Unit 4																								
PO Days (excludes Refurb)	0.0	28.7	56.5	0.0	0.0	66.6	0.0	48.8	87.7	0.0	24.6	84.9	0.0	77.6	0.0	0.0	0.0	0.0	20.0	45.9	0.0	74.9	0.0	0.0
FEPO Days	0.0	1.0	13.9	0.0	0.0	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	6.8	0.0	11.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	29.7	70.4	0.0	6.8	86.7	11.8	48.8	87.7	0.0	24.6	84.9	0.0	77.6	0.0	0.0	0.0	0.0	20.0	45.9	0.0	74.9	0.0	0.0
Darlington All Units																								
PO Days (excludes Refurb)	69.1	170.3	118.2	55.4	56.2	144.5	75.3	242.3	107.3	98.8	107.3	84.9	33.0	155.6	45.1	0.0	86.5	21.7	286.7	512.7	141.5	214.1	139.2	139.2
FEPO Days	0.0	11.9	13.9	0.0	0.0	39.8	0.0	7.7	0.0	0.0	2.8	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	4.9	4.9	7.4	0.0	16.7	24.5	2.8	12.1	2.0	0.0	0.0	0.0	0.0	0.0	12.5	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Darlington Total	69.1	182.2	137.0	60.3	63.6	184.3	92.0	274.5	110.1	110.9	112.1	84.9	34.3	155.6	45.1	0.0	99.0	22.9	286.7	512.7	141.5	214.1	139.2	139.2
Pickering Unit 1																								
PO Days	0.0	0.0	98.0	0.0	106.3	0.0	0.0	101.7	0.0	133.1	2.9	0.0	157.9	0.0	113.1	5.4	0.0	-	-	-	-	-	-	-
FEPO Days	1.1	0.0	12.3	0.0	9.9	109.7	0.0	17.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-
Total	1.1	0.0	110.3	0.0	116.2	109.7	0.0	145.6	0.0	133.1	2.9	0.0	157.9	0.0	113.1	5.4	0.0	-	-	-	-	-	-	-
Pickering Unit 4																								
PO Days	0.0	74.0	46.5	80.9	0.0	20.0	85.3	0.0	107.8	29.3	112.3	0.0	121.6	0.0	30.8	88.2	0.0	-	-	-	-	-	-	-
FEPO Days	0.0	32.5	0.0	6.8	7.4	4.5	34.3	0.0	31.9	0.0	0.0	0.0	13.0	0.0	0.0	2.0	0.0	-	-	-	-	-	-	-
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	31.7	-	-	-	-	-	-	-
Total	0.0	106.5	46.5	87.7	25.4	24.5	119.6	0.0	139.7	29.3	112.3	0.0	134.6	0.0	36.7	90.2	31.7	-	-	-	-	-	-	-
Pickering Unit 5																								
PO Days	0.0	57.3	41.9	113.0	0.0	87.8	0.0	105.9	0.0	121.6	0.0	115.9	0.0	0.0	160.5	0.0	90.1	0.0	0.0	0.0	0.0	0.0	0.0	55.0
FEPO Days	5.3	27.7	0.0	63.9	0.0	53.4	0.0	14.7	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	7.0	85.0	41.9	176.9	0.0	141.2	0.0	120.6	0.0	121.6	0.0	115.9	0.0	33.7	161.6	0.0	90.1	0.0	0.0	0.0	0.0	0.0	0.0	55.0
Pickering Unit 6																								
PO Days	0.0	68.2	39.4	101.1	0.0	113.0	0.0	102.4	1.4	0.0	124.0	0.0	119.4	12.7	28.7	119.6	0.0	73.6	15.0	0.0	0.0	0.0	0.0	0.0
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	68.2	39.4	101.1	0.0	113.0	0.0	102.4	17.6	0.0	124.0	0.0	119.4	12.7	28.7	119.6	0.0	79.9	15.0	0.0	0.0	0.0	0.0	0.0
Pickering Unit 7																								
PO Days	0.0	0.0	117.2	0.0	104.4	0.0	113.9	0.0	117.5	0.0	0.0	109.6	0.0	108.8	26.6	0.0	153.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FEPO Days	0.0	0.0	2.2	0.0	0.0	0.0	7.5	8.5	3.9	11.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.3	25.7	0.0	28.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	119.4	0.0	104.4	0.0	121.4	8.5	121.4	11.6	0.0	109.6	19.3	134.5	26.6	28.6	153.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pickering Unit 8																								
PO Days	60.4	0.0	76.4	0.0	97.4	0.0	85.7	0.0	142.6	0.0	109.9	0.0	0.0	154.5	28.2	113.9	7.5	0.0	95.8	0.0	0.0	0.0	0.0	0.0
FEPO Days	13.2	0.0	7.0	0.0	8.9	0.0	13.6	0.0	41.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.4	0.0	40.6	0.0	7.9	31.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	73.6	0.0	83.4	0.0	106.3	0.0	99.3	13.4	184.0	40.6	109.9	7.9	31.8	154.5	28.2	113.9	7.5	0.0	95.8	0.0	0.0	0.0	0.0	0.0
Pickering All Units																								
PO Days	60.4	199.5	419.4	295.0	308.1	220.8	284.9	310.0	369.3	284.0	349.1	225.5	398.9	276.1	387.9	327.1	251.3	73.6	110.8	0.0	0.0	0.0	0.0	55.0
FEPO Days	19.6	60.2	21.5	70.7	26.2	167.6	55.4	40.5	93.4	11.6	0.0	0.0	13.0	0.0	1.1	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbudgeted Planned Outage	1.7	0.0	0.0	0.0	18.0	0.0	0.0	40.0	0.0	40.6	0.0	7.9	51.1	59.4	5.9	28.6	31.7	6.3	0.0	0.0	0.0	0.0	0.0	0.0
Pickering Total	81.7	259.7	440.9	365.7	352.3	388.4	340.3	390.5	462.7	336.2	349.1	233.4	463.0	335.5	394.9	357.7	283.0	79.9	110.8	0.0	0.0	0.0	0.0	55.0

Attachment 1

Numbers may not add due to rounding

Chart 2 - Outage Days and Production Variance and Revenue Deficiency by Station and Year

	2008[1]	2009[1]	2010[2]	2011[3]	2012[3]	2013[4]	2014[5]	2015[5]	2016[4]	2017[6]	2018[6]	2019[6]	2020[6]	2021[6]	2022[7]	2023[7]	2024[7]	2025[7]	2026[7,12]	2027[8]	2028[8]	2029[8]	2030[8]	2031[8]
Pickering OEB Approved PO Days	179.0	176.0	436.0	304.0	247.0	303.5	292.9	287.9	401.6	541.6	530.8	517.2	498.9	562.8	487.2	371.1	270.2	35.0	0.0	0.0	0.0	0.0	0.0	55.0
Darlington OEB Approved PO Days	75.1	171.7	118.8	68.3	65.5	144.4	77.1	188.0	111.0	148.4	143.3	119.1	183.2	51.2	73.0	112.2	55.0	268.0	59.1	512.7	141.5	214.1	139.2	139.2
Pickering Variance (days) (Actual - OEB/Appr.)	(97.3)	83.7	4.9	61.7	105.3	84.9	47.4	102.6	61.1	(205.4)	(181.7)	(283.8)	(35.9)	(227.3)	(92.3)	(13.4)	12.8	44.9	110.8	0.0	0.0	0.0	0.0	0.0
Pickering Variance (TWh) (Actual - OEB/Appr.)	(1.2)	1.0	0.1	0.8	1.3	1.1	0.6	1.3	0.8	(2.5)	(2.2)	(3.5)	(0.4)	(2.8)	(1.1)	(0.2)	0.2	0.56	1.4	0.0	0.0	0.0	0.0	0.0
Darlington Variance (days) (Actual - OEB/Appr.)	(6.0)	10.5	18.2	(8.0)	(1.9)	39.9	14.9	86.5	(0.9)	(37.5)	(31.2)	(34.2)	(148.9)	104.4	(27.9)	(112.2)	44.0	(245.1)	227.6	0.0	0.0	0.0	0.0	0.0
Darlington Variance (TWh) (Actual - OEB/Appr.)	(0.1)	0.2	0.4	(0.2)	(0.0)	0.8	0.3	1.8	(0.0)	(0.8)	(0.7)	(0.7)	(3.1)	2.2	(0.6)	(2.4)	0.9	(5.2)	4.8	0.0	0.0	0.0	0.0	0.0
Total Variance (TWh)	(1.3)	1.3	0.4	0.6	1.3	1.9	0.9	3.1	0.7	(3.3)	(2.9)	(4.2)	(3.6)	(0.6)	(1.7)	(2.5)	1.1	(4.6)	6.2	0.0	0.0	0.0	0.0	0.0
Revenue Rate ($/MWh) [9]	53.0	53.0	53.0	51.5	51.5	51.5	52.8	59.3	59.3	70.2	78.6	77.0	85.0	89.7	104.1	107.8	103.5	102.9	111.3	206.8	192.5	203.2	200.0	220.7
Revenue Deficiency ($M) [10]	(50.2)	62.4	21.8	28.1	59.3	89.2	43.8	170.4	40.5	(219.2)	(215.9)	(308.6)	(289.9)	(52.7)	(173.5)	(262.4)	107.4	(450.2)	649.8	0.0	0.0	0.0	0.0	0.0

[1] OPG Approved Budget, Ref. EB 2010-008 E2-1-2 Table 1a, 1b

[2] OPG Budget, Ref. EB 2013-0321 E2-1-2 Table 1

[3] Ref. EB 2013-0321 E2-1-2 Table 1

[4] OPG Budget, Ref. EB 2016-0152 E2-1-2 Table 1

[5] Ref. EB 2016-0152 E2-1-2 Table 1

[6] Ref. L-A1-2-Staff-002 / EB-2020-0290

[7] OPG Plan, Ref. EB 2020-0290 E2-1-2 Table 1a, 1b

[8] OPG Plan, Ref. EB 2025-0297 E2-1-2 Table 1a, 1b

[9] 2014 is at rate of $52.82/MWh (10 months at Board approved rate of $51.52/MWh and 2 months at Board approved rate of $59.29/MWh)
2017 is at rate of $70.18 (5 months at Board approved rate of $59.29/MWh and 7 months at Board Approved rate of $77.96)

[10] Revenue Deficiency adjusted for fuel. Revenue Deficiency in 2008 has been adjusted to reflect 9 months per OEB approved rates April 1 2008
Ref. EB-2025-0297 F2-5-1 Table 1a for 2022-2026 fuel costs

[11] Ref. L-E2-STAFF-153 / EB-2025-0297

[12] 2026 TWh variance does not reflect the higher production (Ref. EB-2025-0297 E2-1-2 Table 1b) from Pickering 5-8 extended operation from January 1 to September 30, 2026
as the associated revenue will be refunded to ratepayers through the Pickering B Variance Account

SEC Interrogatory #138

Interrogatory

Reference:
E2-1

Question(s):

Please provide the production forecast (TWh) for each year between 2021 and 2031 (actual/budget and forecast) by nuclear unit.

Response

Refer to Attachment 1.

Numbers may not add due to rounding.

Production Forecast Trend - Nuclear By Unit (TWh)

Line No.	Prescribed Facility	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	Darlington NGS Unit 1	5.5	0.8	0.0	0.4	6.9	7.2	6.1	4.9	7.4	7.1	4.9
2	Darlington NGS Unit 2	7.2	6.0	7.2	4.9	7.5	7.4	0.0	7.4	7.1	4.8	7.6
3	Darlington NGS Unit 3	-0.1	0.0	3.3	6.4	7.2	1.9	6.4	7.1	4.8	7.6	7.2
4	Darlington NGS Unit 4	5.9	7.1	4.1	-0.1	-0.1	4.6	6.2	7.3	5.8	7.4	7.4
5	Pickering NGS Unit 1	4.2	3.0	4.2	3.3	-	-	-	-	-	-	-
6	Pickering NGS Unit 4	4.3	4.0	3.3	4.2	-	-	-	-	-	-	-
7	Pickering NGS Unit 5	3.2	2.4	4.2	2.7	4.1	3.2	0.0	0.0	0.0	0.0	2.0
8	Pickering NGS Unit 6	4.2	4.0	2.9	4.5	3.4	3.0	0.0	0.0	0.0	0.0	0.0
9	Pickering NGS Unit 7	2.8	4.1	4.3	2.6	4.5	3.2	0.0	0.0	0.0	0.0	0.0
10	Pickering NGS Unit 8	2.4	3.9	2.6	4.1	4.5	1.9	0.0	0.0	0.0	0.0	0.0
11	**Total**	**39.6**	**35.3**	**36.1**	**33.0**	**38.1**	**32.5**	**18.7**	**26.7**	**25.1**	**26.8**	**28.9**

12	* DNNP-1	-	-	-	-	-	-	-	-	-	0.5	1.9
13	**DNNP - Total**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**0.5**	**1.9**

* DNNP: Darlington New Nuclear Project

SEC Interrogatory #139

Interrogatory

Reference:
E2-1

Question(s):

Please provide a copy of the annual internal nuclear production forecast for each year between 2022 and 2026.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

Chart 1 provides budgeted annual nuclear production amounts from applicable business plans underpinning the years 2022-2026.

Chart 1: Annual Nuclear Production Budgets 2022-2026

Year	Nuclear Production Amounts (TWh)
2022	33.2
2023	33.8
2024	32.4
2025	36.9
2026	32.5

As applicable, these budgets reflect the continued operation of Pickering Units 5 to 8 to September 30, 2026, and the early return to service of refurbished units at Darlington relative to the EB-2020-0290 forecasts.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the request goes beyond the scope of the OEB's current Filing Requirements, which were subject to extensive consultation in EB-2024-

0136 with the "aim to address the evolving regulatory landscape, *[and] incorporate lessons learned from past proceedings*".[1] (emphasis added)[2]

In accordance with the Filing Requirements, OPG has already provided (ii) 2022-2026 OEB-approved and actual/bridge production values by in Ex. E2-1-2, Tables 1a and 1b, along with (ii) variance explanations of OEB-approved versus actual/bridge production values, as well as year-over-year actual production values in Sections 2.3 and 2.4.

[1] EB-2024-0136, OEB Letter re Updated Filing Requirements for Ontario Power Generation Inc. (September 17, 2024), p. 1.
[2] In accordance with the Filing Requirements, OPG has provided detailed evidence regarding 2022-2026 actual/bridge year forecast nuclear production, along with: (i) variance explanation of OEB-approved versus actual/forecast bridge year production values and (ii) variance explanation of year-over-year production values, in Ex. E1-2-1, Sections 2.2, 2.3 and 2.4.

SEC Interrogatory #140

Interrogatory

Reference:
EB-2020-0290, E2-01-Staff-190

Preamble:

The evidence in EB-2020-0290 was that OPG planned to investigate the use of technology that would allow OPG to reduce the duration of a planned 2022 Pickering VBO.

Question(s):

a) Please provide a result of the investigation and if the new technology was implemented. If it was implemented, please provide details of the results.

b) Is the same technology applicable to the planned Darlington VBO, and if so, has it been included in the forecast length of the outage?

Response

a) The new technology identified in EB-2020-0290, Ex. L-E2-01-Staff-190 was implemented in the scheduled 2022 Pickering VBO. This included use of drones with cameras to support periodic inspection programs (i.e., CSA N285 & CSA N287) such as emergency water storage tank inspections and executing other inspections outside of the vacuum building while the station is online. The use of this new technology resulted in reduced need for extensive scaffolding and efficiency gains versus typical visual inspections. The Pickering 2022 VBO duration was 28 days (i.e., last unit off to first unit on), which was ahead of the 30-day scheduled duration and was shorter than Pickering 2000 VBO and 2010 VBO durations. Final Pickering 2022 VBO costs were within the approved budget.

b) Yes, the same technology is applicable to the planned Darlington VBO and the use of this technology is reflected in its forecast duration.

SEC Interrogatory #141

Interrogatory

Reference:
EB-2020-0290, L-E2-01-OAPPA-002, Attachment 1

Question(s):

With respect to EB-2020-0290, L-E2-01-OAPPA-002, Attachment 1:

a) Please provide a revised version of the table that includes the actual/revised budgeted outage duration (days) for each planned outage.

b) Please provide a revised version of the table for all planned outages between 2027 and 2031.

Response

a) Refer to Attachment 1, which reflects actual (2022-2025) / current budgeted (2026) outage duration (days) for each planned outage.

b) Refer to Attachment 2.

Outage Durations - Actual (2021-2025) / Budget (2026)

Year	Station	Outage	Unit	Description	EB-2020-0290 Outage Duration (days)	Actual / Current Budget Duration (days) **1** *	
2022	PN	P2251	Unit 5	Planned Outage	164.2	129.6	
		P2171	Unit 7	Planned Outage	24.9	0.0	
		P2211	Unit 1	Planned Outage	113.1	113.1	
		P2241	Unit 4	Vacuum Building Outage	30.0	30.8	
		P2252	Unit 5	Vacuum Building Outage	30.0	30.9	
		P2261	Unit 6	Vacuum Building Outage	30.0	28.7	
		P2271	Unit 7	Vacuum Building Outage	30.0	26.6	
		P2281	Unit 8	Vacuum Building Outage	30.0	28.2	
		N/A	Unit 1,4,5-8	Equipment Aging Outage	35.0	5.9	
				Total	487.2	393.8	
	DN	D2221	Unit 2	Post Refurbishment Outage	43.0	45.1	
		N/A	Unit 1-4	Equipment Aging Outage	30.0	0.0	
				Total	73.0	45.1	
	Total 2022				560.2	438.9	
2023	PN	P2361	Unit 6	Planned Outage	132.3	119.6	
		P2211	Unit 1	Planned Outage	19.5	5.4	
		P2341	Unit 4	Planned Outage	70.2	88.2	
		P2381	Unit 8	Planned Outage	114.1	113.9	
		N/A	Unit 1,4,5-8	Equipment Aging Outage	35.0	28.6	
				Total	371.1	355.6	
	DN	D2321	Unit 2	Planned Outage	82.2	0.0	
		N/A	Unit 1-4	Equipment Aging Outage	30.0	0.0	
				Total	112.2	0.0	
	Total 2023				483.3	355.6	
2024	PN	P2381	Unit 8	Planned Outage	2.2	7.5	
		P2471	Unit 7	Planned Outage	132.2	153.7	
		P2451	Unit 5	Planned Outage	100.8	90.1	
		N/A	Unit 1,4,5-8	Equipment Aging Outage	35.0	31.7	
				Total	270.2	283.0	
	DN	D2431	Unit 3	Post Refurbishment Outage	55.0	7.1	
		D2423	Unit 2	Equipment Risk Outage		5.5	
		D2421	Unit 2	Planned Outage		86.5	**2**
				Total	55.0	99.0	
	Total 2024				325.2	382.1	
2025	PN	N/A	Unit 5-8	Equipment Aging Outage	35.0	6.3	
		P2561	Unit 6	Planned Outage		73.6	**3**
				Total	35.0	79.9	
	DN	D2531	Unit 3	Post Refurbishment Outage	31.0	0.0	
		D2511	Unit 1	Post Refurbishment Outage	55.0	22.9	
		D2521	Unit 2	Planned Outage	182.0	0.0	**2**
				Total	268.0	22.9	
	Total 2025				303.0	102.8	
2026	PN	N/A	Unit 5-8	Equipment Aging Outage		23.0	
		N/A	Unit 5-8	Staggered Shutdown		15.0	**4**
		P2681	Unit 8	Planned Outage		72.8	**5**
				Total	0.0	110.8	
	DN	D2521	Unit 2	Planned Outage	8.1	0.0	
		D262	Unit 2	Planned Outage	20.0	0.0	
		D2631	Unit 3	Planned Outage		266.7	**6**
		D2611	Unit 1	Post Refurbishment Outage	31.0	20.0	
				Total	59.1	286.7	
	Total 2026				59.1	397.5	

NOTES: **1** Actual for 2021 - 2025 and Revised Budget for 2026
2 D2 outage advanced from 2025 (D2521) to 2024 (D2421)
3 New P6 outage added to support PBX
4 Impact of 15 days due to staggered shutdown of Units 5 to 8
5 New P8 outage added to support PBX
6 D3 outage advanced from 2027 as DNRU3 completed ahead of schedule
***** Numbers may not add due to rounding

Planned Outages (2027-2031)

Year	Station	Outage	Unit	Description	EB-2025-0297 Outage Duration (days) *
2027	DN	D2721	Unit 2	Planned Outage	360.0
		D2711-VBO	Unit 1	Planned Outage - VBO	45.9
		D2731-VBO	Unit 3	Planned Outage - VBO	45.9
		D2741-VBO	Unit 4	Planned Outage - VBO	45.9
		N/A	Unit 1-4	Equipment Risk Outage	15.0
		Total			512.7
	Total 2027				512.7
2028	DN	D2721	Unit 2	Planned Outage	6.3
		D2811	Unit 1	Planned Outage	120.2
		N/A	Unit 1-4	Equipment Risk Outage	15.0
		Total			141.5
	Total 2028				141.5
2029	DN	D2941	Unit 4	Planned Outage	74.9
		D2931	Unit 3	Planned Outage	124.2
		N/A	Unit 1-4	Equipment Risk Outage	15.0
		Total			214.1
	Total 2029				214.1
2030	DN	D3021	Unit 2	Planned Outage	124.2
		N/A	Unit 1-4	Equipment Risk Outage	15.0
		Total			139.2
	Total 2030				139.2
2031	PN	P3151-PR1	Unit 5	Post Refurbishment Outage	55.0
		Total			55.0
	DN	D3111	Unit 1	Planned Outage	124.2
		N/A	Unit 1-4	Equipment Risk Outage	15.0
		Total			139.2
	Total 2031				194.2

2031	DNNP	S3111-PR1	Unit 1	Warranty Outage	15.0
		S3111	Unit 1	Planned Outage	49.9
		Total			64.9

Note: Numbers may not add due to rounding

SEC Interrogatory #142

Interrogatory

Reference:
E2-1-1

Question(s):

Please update Charts 2-4 to include 2025 actuals.

Response

The updated versions of Ex. E2-1-1, Charts 2-4, with 2025 actuals, are presented as Charts 1-3 below:

Chart 1 – Updated Ex. E2-1-1, Chart 2
Planned Outage Durations with 2025 Actuals[1,2]

	2022	2023	2024	2025
Pickering Planned Outage Days (OEB Approved)	487.2	371.1	270.2	35.0
Pickering Planned Outage Days (Actuals)	393.8	355.6	283.0	79.9
Variance	93.4	15.5	-12.8	-44.9
Darlington Planned Outage Days (OEB Approved)	73.0	112.2	55.0	268.0
Darlington Planned Outage Days (Actuals)	45.1	0.0*	99.0	22.9
Variance	27.9	112.2	-44.0	245.1

[1] Includes Unbudgeted Planned Outage days. Excludes Planned Outage days for the Darlington Refurbishment Program.
[2] Does not reflect the EB-2020-0290 settlement adjustment for production forecast.
* Darlington Unit 2 PO deferred from 2023 to 2024.

Chart 2 – Updated Ex. E2-1-1, Chart 3
Pickering Forced Loss Rate with 2025 Actuals

	2020	2021	2022	2023	2024	2025	Avg.	10-Year Avg.
FLR- Actual (%)	2.7	6.2	1.8	2.8	2.6	3.0	**3.2**	**3.5**
OEB-Approved (%) [1]	5.0	5.0	3.5	3.5	3.5	3.5	**4.0**	**4.4**

[1] EB-2020-0290, Ex. E2-1-2, Table 1

Chart 3 – Updated Ex. E2-1-1, Chart 4
Darlington Forced Loss Rate with 2025 Actuals

	2020	2021	2022	2023	2024	2025	Avg.	10-Year Avg.
FLR- Actual (%)	1.5	3.5	7.5	1.4	12.1	2.0	**4.7**	**3.8**
OEB Approved (%) [1]	4.2	3.0	2.1	1.2	6.0	6.4	**3.8**	**2.7**

[1] EB-2020-0290, Ex. E2-1-2, Table 1

SEC Interrogatory #143

Interrogatory

Reference:
E2-1-2, p. 4-7

Question(s):

Based on the explanation of variances between actuals/budget and approved, please confirm the impact between 2022 and 2026 on the actual/budget production forecast compared to approved as a result of the DRP being ahead of schedule is 10.4 TWh (2022: 0, 2023: +2.3, 2024: +0.7, 2025: +3.5, 2026: +3.9). If not confirmed, please provide the correct amount by year.

Response

Not confirmed. The net impact between 2022 and 2026 on the actual/budget production compared to OEB-approved values, prior to settlement adjustment, as a result of the DRP being ahead of schedule is 3.5 TWh (2022: 0, 2023: +2.3, 2024: +0.7, 2025[1]: +2.2, 2026: -1.7). As a result of Darlington Unit 3 returning to service in July 2023, the previous Unit 3 outage planned for 2027 was advanced to 2026 to align with Darlington's 36-month outage interval in line with regulatory requirements. The Unit 3 planned outage advancing to 2026 adds 266.7 planned outage days (-5.6 TWh) in that year.

[1] Reflects 2025 actual results.

SEC Interrogatory #144

Interrogatory

Reference:
E2-1-2

Question(s):

Please provide a table that shows all planned 2027-2031 outages that were included in EB-2020-0290 for 2022-2026 production forecast that have been deferred into the 2027-2031 period. For each, please explain the reason for the deferred outage, provide the forecast length of time (days) and production impact (TWh) in EB-2020-0290, and the revised forecast length of time (days) and production impact (TWh).

Response

No planned outages included in EB-2020-0290 for the 2022-2026 nuclear production forecast were subsequently deferred into the 2027-2031 period. Refer to Ex. L-D2-Staff-082 for a discussion of production impacts in respect of the deferral of scope associated with the Turbine Controls and Auxiliary System Upgrade project.

SEC Interrogatory #145

Interrogatory

Reference:
E2-1-2, p. 11

Question(s):

Please provide further details regarding the DNNP 2031 warranty outage. Please provide the length of time (days) and production impact (TWh).

Response

As described in Ex. E2-1-1, p. 16, lines 1-11, a DNNP Unit 1 outage is planned to address equipment issues that are expected to emerge within the first six months of commencing operation (i.e., "warranty outage"). The length of this forecasted warranty outage is 15 days, and the production impact is 0.1 TWh in 2031.

Board Staff Interrogatory #153

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) Refer to Ex. L-A1-CCC-001, Attachment 1, Tables 30 and 31.

Board Staff Interrogatory #154

Interrogatory

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

Preamble:

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

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

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

Question(s):

a) Please provide a chart/table that provides a Unit-by-Unit summary of actual forced loss rates at Darlington between 2020 and 2024 and forecasted forced loss rates between 2025 and 2031 (with actuals for 2025 if available). Please also include a summary of corresponding forced loss rate days equivalent.

b) Please elaborate on how OPG's operating experience and lessons learned from Darlington Units 2 and 3 led to reduced forced loss rate targets for Darlington Units 1 and 4.

c) Pickering's Unit 5 forced loss rate is set at 12% for the first-year post refurbishment; DNNP Unit 1 forced loss rate is also set at 12% for its first year of operation. Why are the forecasted forced loss rate for Darlington Units 1 and 4 so much lower during their first and second years of operation (i.e., 6% and 4%)?

d) Please describe how OPG's operating experience and lessons learned from Darlington Units 2 and 3 have informed forced loss rate targets for Pickering Unit 5 and DNNP Unit 1.

Response

a) For 2020-2025 actuals, Chart 1 provides the Darlington unit by unit FLR and Chart 2 provides the FLR equivalent days.

Chart 1 – 2020-2025 Darlington Actual FLR %

FLR	2020	2021	2022	2023	2024	2025
D1	0.7	5.2	0.4	-	28.8	1.3
D2	4.7	4.4	9.3	1.9	12.5	0.5
D3	0.0	-	-	2.0	9.9	4.3
D4	1.4	0.7	6.8	0.2	-	-

Chart 2 – 2020-2025 Darlington Actual FLR Equivalent Days

FLR Eq. Days	2020	2021	2022	2023	2024	2025
D1	2.7	14.9	0.2	-	11.4	4.2
D2	10.1	16.2	29.6	6.7	34.0	1.7
D3	0.1	-	-	3.4	34.3	15.6
D4	4.8	1.9	25.0	0.4	-	-

For the forecasted period between 2026-2031, Chart 3 provides the Darlington forecasted unit by unit FLR and Chart 4 provides FLR equivalent days.

Chart 3 – 2026-2031 Darlington Forecast FLR %

FLR	2026	2027	2028	2029	2030	2031
D1	3.8	2.0	2.0	2.0	2.0	2.0
D2	2.0	2.0	2.0	2.0	2.0	2.0
D3	2.0	2.0	2.0	2.0	2.0	2.0
D4	6.0	4.6	2.7	2.0	2.0	2.0

Chart 4 – 2026-2031 Darlington Forecast FLR Equivalent Days

FLR Eq. Days	2026	2027	2028	2029	2030	2031
D1	14.0	6.1	4.9	7.3	7.0	4.8
D2	7.3	0.1	7.2	7.0	4.8	7.3
D3	2.0	6.4	7.0	4.8	7.3	7.0
D4	14.5	14.8	9.7	5.8	7.3	7.3

b) The operating experience (“OPEX”) and lessons learned from post-refurbishment Darlington Unit 2 and Unit 3 FLR events like the Unit 2 Turbine Reheat Intercept Stop Valve Failure and the Unit 3 Boiler Tube Leak have resulted in updates to procedures, changes to maintenance practices and inspection activities during Darlington Unit 1 and Unit 4 refurbishments, thus reducing the likelihood of similar FLR events occurring on those units post refurbishment.

c) and d)

Per the response to part b) above, the OPEX and lessons learned from Darlington Unit 2 and Unit 3 have been applied to Darlington Unit 1 and Unit 4, allowing post-refurbishment FLR targets for Units 1 and 4 to be reduced.

The reference 12% FLR forecast for Pickering Unit 5 and DNNP Unit 1 are informed by industry performance following major refurbishment programs. While OPEX and lessons learned from Darlington Units 2 and 3 have been evaluated and considered in developing forecasted FLR for Pickering Unit 5’s first year post-refurbishment and for the DNNP Unit 1’s first year of operations, reducing the 12% FLR forecast for each of these units would be unwarranted as there are not any unit-specific FLR lessons learned to apply. In particular, Pickering Refurbishment has increased scope and complexity compared to the Darlington Refurbishment, resulting in increased potential for forced loss events in the first year of operations, while DNNP Unit 1 is a first-of-a-kind project and may be subject to post-commissioning operating risks and complexities that are not yet known.

Board Staff Interrogatory #155

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) As discussed in Ex. E2-1-1, Section 3.3, FLR targets are based on historical plant performance, any known improvements or component condition issues, initiatives to improve equipment reliability, and with consideration of post-refurbishment risks. The FLR targets are established as described in Ex. F2-1-1, Section 3.3.

   As noted in Ex. F2-1-1, p. 26, the 2.0% FLR target for Darlington has been set to drive improvement from the recent performance. This takes into consideration the following over the 2028-2031 period:

   - Historical Darlington FLR as shown in Ex. E2-1-1, Chart 4.
   - The impact of major replacement or rehabilitation projects over the IR term like the Unit 2 Turbine Control and Auxiliary Systems Upgrade, Unit 3 and Unit 2 Steam Generator Primary Moisture Separator Replacements, Unit 1 and Unit 2 Generator Stator Rewind, and Turbine Rotor Replacement.
   - Implementation of nuclear-specific initiatives as discussed in Ex. F2-1-1, Section 3.4.2.1, which support target achievement.

Board Staff Interrogatory #156

Interrogatory

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

Preamble:

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

Question(s):

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

b) Please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term and in the 2027-2031 rate term of deferring the Unit 2 PMS replacement work from 2025 to 2027.

c) If the Unit 3 PMS replacement work is a deferral of work that OPG initially planned to undertake earlier in the 2022-2026 IR term, please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term of the deferral.

d) Did OPG complete the PMS replacements associated with the four Steam Generators at Unit 1 and the PMS replacements associated with the four SGs at unit 4 during the Unit 1 and Unit 4 refurbishment outages? If not, please clarify.

Response

a) The OEB-approved production forecast for 2022-2026 did not account for the impact from Darlington Steam Generator ("SG") PMS replacement work as the need for this emergent work was established subsequently.

b) As discussed in part a), the OEB-approved production forecast for 2022-2026 did not account for any Darlington SG PMS replacement work. The Unit 2 PMS replacement work has been scheduled for the 2027 Unit 2 planned outage and was not deferred from 2025. For clarity, there was no Unit 2 Darlington refurbishment window to undertake such work during 2022-2026 once the need was established.

c) As discussed in part a), the OEB-approved production forecast for 2022-2026 did not account for any Darlington SG PMS replacement work. As the Unit 3 refurbishment was already underway at the time the need for this emergent project was established, OPG was able to undertake two SG PMS replacements during the remaining Unit 3 refurbishment outage window. The other two replacements are planned to be undertaken in a 2026 Darlington outage, the net impact of which is -3.7 TWh in 2026.

d) Yes, OPG completed PMS replacements of four SGs on Unit 1 and four SGs on Unit 4 in the Unit 1 and Unit 4 refurbishment outage windows at Darlington.

Board Staff Interrogatory #157

Interrogatory

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

Preamble:

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

Question(s):

a) Please clarify whether any of the projects cited in the preamble are deferrals of work initially planned for the 2022-2026 rate term.

b) If any of the projects cited in the preamble are deferrals form the 2022-2026 rate term, please estimate and explain the electricity production impact, if any, in the 2022-2026 rate term and in the 2027-2031 rate term.

c) Please explain how, if at all, the OEB-approved production forecast for 2022-2026 accounted for the Primary Moisture Separators (PMS) replacement outages.

Response

a) and b)

None of the projects cited in the preamble are deferrals of work initially planned for the 2022-2026 rate term. As discussed in Ex. E2-1-1, these projects are emergent equipment replacements, rehabilitations and works required to address reliability risks to Darlington's post-refurbishment operations.

c) Refer to Ex. L-E2-Staff-156.

Board Staff Interrogatory #158

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) Confirmed. OPG currently expects to complete the final unit’s installation during a Unit 4 outage outside of the 2027-2031 rate term.

Board Staff Interrogatory #159

Interrogatory

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

Preamble:

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

Question(s):

a) Please elaborate on why the Unit 2 Turbine Control and Auxiliary Systems Upgrade project was deferred from 2025 to 2027.

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

Response

a) As discussed in Ex. D2-1-3, Section 3.1.3, and in Ex. E2-1-1, the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project was deferred to support grid reliability and manage resource constraints. Specifically, the Darlington Unit 2 planned outage window overlapped with multiple other nuclear outages in the province, including two Darlington Refurbishment outages, a Bruce Power Major Component Replacement outage, and a Pickering planned outage.

b) Not confirmed. OPG plans to commence and complete the Unit 2 Turbine Control and Auxiliary Systems Upgrade project during the Unit 2 Darlington PMS replacement outage in 2027. The Unit 2 Turbine Controls Upgrade will not involve additional outage time beyond that required for the PMSR work, other than 15 incremental days at the end of the outage to complete dynamic high-power testing and commissioning activities. Refer to Ex. L-D2-Staff-082 for more information.

VECC Interrogatory #009

Interrogatory

Reference:
Exhibit E2, Tab 1, Schedule 1, Table 1

Question(s):

a) Please update Table 1 (Production Trend) to show actual 2025 results.

Response

a) Refer to Ex. L-A1-CCC-001.

VECC Interrogatory #010

Interrogatory

Reference:
Exhibit E2, Tab 1, Schedule 2, page 15 / Table 1b

Preamble:

"Notwithstanding the recent FLR performance at Darlington, and the need to execute major replacement and rehabilitation projects in support of post-refurbishment operations during the IR term, Darlington continues to target an improved FLR performance, set at 2.0% FLR over the 2028-2031 period once Units 1 and 4 enter their third year of post-refurbishment operations."

Question(s):

a) Please confirm (or correct) that a FLR rate is included as an adjustment (downward) in nuclear power production.

b) The above reference indicates that a 2.0% FLR rate is being applied over the 2028-02031 period to the Darlington NGS. At Table 1b it shows (line 6) a FLR rate for Darlington NGS of 2.9% in 2027, 2.2% for 2028 and 2.0% only beginning in 2029. Please explain why the 2027 and 2028 FLR rate is higher than 2.0%.

c) What would be the impact in production if the FLR rate for 2027 and 2028 were set at 2.0%?

Response

a) Confirmed.

b) The FLR rates for 2027 (2.9%) and 2028 (2.2%) reflect the average FLR target for the station, which is higher than 2.0% because Darlington Unit 4 will not have reached the third year of post-refurbishment operations until 2028. As discussed in Ex. E2-1-1, Section 3.1, p. 11, lines 24-29, post-refurbishment FLR targets are above 2.0% during the first two years of post-refurbishment operations, reflecting industry operational experience. In 2027 and 2028, Units 1, 2 and 3 have a 2.0% sustaining FLR target, whereas Unit 4 reaches its third year of post-refurbishment operation by 2028. This results in a blended station average above 2.0% for 2027 and 2028, before all units converge to the 2.0% target in 2029.

c) While it would not be appropriate to set the FLR target to 2.0% for the entire station for the reasons described in part b), if the FLR rate for 2027 and 2028 were set at 2.0% for the entire station, the impact to forecast production would be an increase of 0.19 TWh in 2027 and 0.05 TWh in 2028, respectively.