CCC Interrogatory #096

Interrogatory

Reference:
Exhibit G1, Tab 1, Schedule 1, p. 9

Preamble:

OPG's HIM forecasting has been updated to incorporate features of the redesigned HIM in the Renewed Market as described in Ex. E1-2-1. These include the shift from monthly to daily averaging, the replacement of the Hourly Ontario Energy Price with LMP, and the introduction of a Day-Ahead HIM. While OPG's models reflect the design of the Renewed Market, forecasting HIM net revenues is subject to uncertainties.

The expected integration of battery energy storage facilities between 2025 and 2028 is expected to put downward pressure on LMP price spreads, reducing OPG's opportunities to earn HIM net revenues. The outcomes of the first few months of the Renewed Market are not sufficient to serve as a dependable model input on account of high month-to-month variability.

Question(s):

Given OPG's assertion that "the outcomes of the first few months of the Renewed Market are not sufficient to serve as a dependable model input", please explain further why OPG believes it is appropriate to both: (i) fix the HIM incentive forecast for rate setting purposes for the IR term based on the 2027 forecast; and (ii) eliminate 50/50 sharing above the forecast threshold, a mechanism design to protect customers against forecast uncertainty.

Response

With respect to the HIM offset, the current amount embedded in the hydroelectric payment amounts is not reflective of either recently observed market outcomes or expected conditions under the Renewed Market. As shown in Chart 1 below, except for 2025, actual HIM revenues from 2016 to 2024, and forecast HIM revenues for 2026-2027 are materially lower that the $54.5M HIM revenue threshold established in EB-2013-0321. Accordingly, it is appropriate to update the HIM forecast to better align with both historical experience and forward-looking expectations under the Renewed Market.

Additional information on the 2025 HIM revenue is provided in Ex. L-G1-Staff-242.

Chart 1
Actual HIM Revenues Compared to HIM Revenue Threshold ($M)

	2016	2017	2018	2019	2020	2021
HIM Revenues	14.0	12.3	10.9	6.2	5.1	16.8
HIM Revenue Threshold (EB-2013-0321)	54.5	54.5	54.5	54.5	54.5	54.5
Variance	(40.5)	(42.2)	(43.6)	(48.3)	(49.4)	(37.7)
	2022	**2023**	**2024**	**2025**		
HIM Revenues	14.3	14.8	28.4	49.7		
HIM Revenue Threshold (EB-2013-0321)	54.5	54.5	54.5	54.5		
Variance	(40.2)	(39.7)	(26.1)	(4.8)		

An incentive rate-setting mechanism ("IRM") framework relies on establishing a representative base year (2027) from which amounts are escalated mechanistically over the IR term. Fixing the HIM forecast based on the 2027 outlook is therefore consistent with the IRM approach and provides a reasonable foundation for rate-setting purposes.

With respect to the removal of 50/50 sharing above the forecast threshold, OPG's proposal aligns with the Market Surveillance Panels Monitoring Report 32 recommendation to remove the sharing of HIM net revenues exceeding a threshold. OPG's evidence demonstrates that the sharing of revenues above the threshold may reduce incentives for efficient participation in the market. Sharing incremental HIM revenues above the threshold could create an economic disincentive by increasing the spread required cycle the Sir Adam Beck Pumped Storage Generating Station ("PGS"), thereby limiting the extent of time-shifting. Removing this sharing mechanism strengthens the incentive for OPG to shift production regardless of HIM revenues, including increased utilization of the PGS, in response to market price signals. As demonstrated in the customer benefit analysis (Ex. E1-2-1, Attachment 1), increased time-shifting results produces net benefits for customers, aligning OPG's incentives with customer interests over the IR term.

SEC Interrogatory #201

Interrogatory

Reference:
G1-1-1, Table 1

Question(s):

With respect to hydroelectric other revenue:

a) Please provide 2025 actuals.

b) Please explain the forecasted drop in Ancillary Services revenue (line 1) in 2026 and 2027 from the 2016-2024 average.

Response

a) Refer to Ex. L-A1-CCC-001, Attachment 1, Table 64.

b) The 2026 and 2027 hydroelectric Ancillary Services forecast revenues are lower than the historical average for 2016-2024, primarily due to lower forecasted Operating Reserve ("OR") and the impact of the Niagara Hydrogen Center ("NHC") on the Regulation Service revenues as described in Ex. L-G1-Staff-241.

As discussed in Ex. E1-2-1, Section 6.1, OPG expects the addition of approximately 3,000 MW of battery energy storage facilities in Ontario between 2025-2028. This increase in battery energy storage is expected to reduce OR prices going forward due to increased supply and competition in the OR markets.

Board Staff Interrogatory #238

Interrogatory

Reference:
Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 10
Ref 2: Exhibit G1 / Tab 1 / Schedule 1 / Table 1

Preamble:

At Reference 1, it notes that OPG is proposing to retain 20% of the net revenues from the sale of Clean Energy Credits (CECs). It states that, under O. Reg 39/23 (s. 4.2), "the Province specifies that the proceeds OPG is to remit is equivalent to 80% of its revenues net of costs from the sale of CECs to the Province's Future Clean Electricity Fund". OPG notes it is proposing to retain all the remaining net revenues from the sale of CECs "to provide an appropriate incentive for the organization to continue pursuing CEC sales."

At Reference 2, unlike the other sources of non-energy revenues, the table includes no row to address CECs (and the associated actual and forecast revenues).

In an OPG letter dated July 15, 2022 (responding to an OEB letter), OPG provided actual revenues and volumes of OPG's CECs from July 1, 2014 through December 31, 2021. In 2021, CEC revenues had increased to $5.5 million. OPG also provided forecast revenues and production quantities for 2022 – 2026 in that letter.

OPG's 2024 Annual Report (p.63) states: "In January 2025, OPG entered into an agreement with … Magna International Inc. … to supply CECs sourced from the Sir Adam Beck hydroelectric generating complex."

Question(s):

a) Please provide the actual annual revenues and production quantities for 2022-2024, and a forecast of annual revenues and production quantities for the IR term (separately for the regulated Hydroelectric and Nuclear facilities). Please reflect the new agreement with Magna in the forecast.

b) Does contributing to the Clean Electricity Fund provide an incentive for OPG to pursue CEC sales? Please explain.

c) In prior OPG applications, forecasts of all nuclear non-energy revenues have been treated as an offset in the calculation of OPG's nuclear revenue requirement. Please explain why CEC revenues should be treated differently.

d) OPG has proposed a revenue requirement for the IR term. How would OPG use these additional CEC revenues?

Response

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

a) The requested actual and forecast annual CEC revenues and production quantities are provided in Charts 1-4.[1]

Chart 1
Clean Energy Credit Actual Revenues for 2022-2025

	2022	2023	2024	2025
Hydro ($M)	[redacted]			
Nuclear ($M)				
Total ($M)				

[1] It should be noted that Clean Energy Credits are sometimes sold for past years, meaning that the vintage year for a volume of Clean Energy Credits sold may not align with the year in which the revenue is earned. For example, a sale of 2017 Clean Energy Credits that took place in 2022 would show in 2017 volumes and 2022 revenues.

Chart 2
Clean Energy Credit Forecast Revenues for 2026-2031

	2026	2027	2028	2029	2030	2031
Hydro ($M)						
Nuclear ($M)						
Total ($M)						

Chart 3
Clean Energy Credit Actual Production for 2022-2025

	2022	2023	2024	2025
Hydro (TWh)				
Nuclear (TWh)				
Total (TWh)				

Chart 4
Clean Energy Credit Forecast Production for 2026-2031

	2026	2027	2028	2029	2030	2031
Hydro (TWh)						
Nuclear (TWh)						
Total (TWh)						

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) pertaining to regulated hydroelectric facilities is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor which relies on a five-year forecast of capital related revenue requirement, OPG's proposed hydroelectric rate-setting methodology is based on a cost of service 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) No, contributing to the Future Clean Electricity Fund does not create an incentive for OPG to pursue CEC sales. OPG allocates 80% of its net revenue from CEC sales to the fund because O. Reg 39/23 stipulates this contribution. OPG does not control how the proceeds in the fund are allocated. O. Reg 39/23 permits OPG to retain 20% of net CEC revenues, providing a modest incentive for OPG to participate in the CEC market.

c) CEC revenues should be treated differently than other non-energy revenues because they are subject to the framework established under O. Reg. 39/23, which requires OPG to remit 80% of the net revenues from CEC sales to the Province of Ontario's Future Clean Electricity Fund. As a result, the majority of CEC revenues do not accrue to OPG.

   Given that these revenues are largely directed to the Province of Ontario pursuant to regulation, they do not represent revenues available to offset OPG's revenue requirement in the same manner as other examples of non-energy revenues.

d) O. Reg 39/23 permits OPG to retain 20% of net CEC revenues, which contribute to OPG's revenues, providing a modest incentive for OPG to participate in the CEC market.

Board Staff Interrogatory #239

Interrogatory

Reference:
Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Exhibit G1 / Tab 1 / Schedule 2 / p. 2

Preamble:

At Reference 1, the table shows that, in 2024, actual revenues related to Capacity Exports are about double the revenues in the prior years. Then revenues are forecast to decline back to prior year levels over the IR term.

At Reference 2, OPG explains that Installed Capacity (ICAP) Market revenue is $1.5 million higher than 2023 mostly due to OPG clearing the New York Independent System Operator capacity auction for more commitment months in 2024.

Question(s):

a) Please explain why the higher ICAP revenues that were realized in 2024 is considered to be an outlier by OPG. Please discuss whether 2024 ICAP revenues could indicate a potential trend.

Response

a) ICAP revenues recorded in 2024 exceeded historical averages for two primary reasons. Firstly, in 2024, the IESO allowed for a higher level of participation in the New York Independent System Operator ("NYISO") capacity market relative to prior periods. Supply and demand conditions are expected to tighten in Ontario as Pickering Units 5-8 come offline for refurbishment in 2026. Accordingly, OPG does not anticipate that the IESO will allow for capacity exports in as many delivery periods or at comparable volumes in the future due to potential adequacy and reliability concerns. Secondly, NYISO reduced allowable capacity sales from Ontario in June 2025, as shown in Chart 1 below. Further reductions were experienced in the 2026 May-October auction timeframe. As a result of this declining trend, OPG does not anticipate that the elevated ICAP revenues experienced in 2024 will persist.

Chart 1
NYISO Installed Capacity External Rights Availability[1]

	January to April	May to October	November to December
2023	23 MW	80 MW	80 MW
2024	80 MW	37 MW	37 MW
2025	37 MW	13 MW	13 MW
2026	13 MW	4 MW	TBD

[1] Installed Capacity - External Rights Availability, Accessed on March 17, 2026

Board Staff Interrogatory #240

Interrogatory

Reference:
Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 5

Preamble:

At Reference 1, in explaining Operating Reserve (OR) revenues, OPG says an "expected addition of approximately 3,000 MW of battery energy storage facilities between 2025-2028 will put downward pressure on OR prices". That 3,000 MW expected increase in battery energy storage is also discussed in other parts of the Application within the context of lower revenues and/or lower prices relative to "those experienced the Legacy Market".

Question(s):

a) Please identify the source of this forecast increase of 3,000 MW by 2028. If it is an OPG forecast, please explain the basis for the 3,000 MW of new battery energy storage facilities.

Response

a) The projected addition of approximately 3,000 MW of battery energy storage facilities between 2025 and 2028 is based on the IESO's Resource Adequacy Framework, according to which Ontario's entire battery storage fleet is expected to consist of 26 facilities with total capacity of 2,916 MW by 2028.[1]

[1] IESO, "IESO Resource Adequacy Update", May 9, 2024 <https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-adequacy/ieso-resource-adequacy-update-May2024.pdf>.

Board Staff Interrogatory #241

Interrogatory

Reference:
Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / p. 3

Preamble:

At Reference 1, OPG explains the provision of Regulation Service at Sir Adam Beck 2 Generation Station requires turbine modulation that can result in a portion of water flows not being utilized by OPG for electricity production (Unutilized Water). OPG further notes that the Niagara Hydrogen Centre (NHC), which is to be constructed and operated by Atura H2 LP (and is expected to enter service in 2026), will make use of the Unutilized Water. OPG also states the new agreement is consistent with the expectations set out in the Minister of Energy's letter to the IESO dated December 9, 2022.

OEB staff notes that the Application does not appear to indicate what happens with the revenues under OPG's new Regulation Service agreement with Atura H2 LP (a subsidiary of OPG) who uses the Unutilized Water from an OPG regulated facility.

Question(s):

a) Please clarify how OPG proposes to treat these revenues. In doing so, please explain how the following from the December 2022 Minister's letter has been reflected: "I understand from the IESO that OPG might agree to a reduction in compensation in the order of $1 million per year under a new contract."

b) Please clarify how Regulation Service revenues were treated in the past (i.e., prior to Atura H2 LP being involved).

Response

a) OPG would like to clarify that the Regulation Service Agreement is between OPG and the IESO for the provision of Regulation Service, which assists the IESO in balancing supply and demand on the provincial grid. Consistent with the expectations set out in the Minister of Energy's letter to the IESO dated December 9, 2022, Atura H2 LP does not compensate OPG for the electricity it receives behind the meter, generated from Sir Adam Beck 2 GS using Unutilized Water, at the direction of the IESO under the Regulation Services Agreement. Rather, the NHC facility supports OPG's provision of Regulation Service to the IESO-

administered market (in tandem with Sir Adam Beck 2 GS) by taking electricity for hydrogen production at times when the IESO requires Sir Adam Beck 2 GS to reduce its output to the grid, which enables OPG to reduce downward modulation of the facility and associated wear and tear, at no cost to OPG. To reflect this, payments to OPG under the Regulation Service Agreement between OPG and the IESO are reduced by up to $1 million per calendar year going forward based on the use of Unutilized Water to produce energy to support hydrogen production at the NHC while providing Regulation Service and has been reflected accordingly in the ancillary revenues forecast provided in Ex. G1-1-1, Table 1, based on the expected starting timeframe in 2026.

b) Regulation Service revenues are treated as an offset to the regulated hydroelectric revenue requirement, as part of the overall Ancillary Services Revenue offset. This is the same treatment that OPG has applied since its first payment amounts proceeding, EB-2007-0905. Ancillary Services Revenue for the regulated hydroelectric facilities are subject to the Ancillary Services Net Revenue Variance Account (refer to Ex. H1-1-1, Section 5.2).

Board Staff Interrogatory #242

Interrogatory

Reference:
Ref 1: Exhibit G1 / Tab 1 / Schedule 1 / Table 1

Preamble:

OEB staff created the chart below based on the Hydroelectric Incentive Mechanism (HIM) revenues provided by OPG in Table 1 of Reference 1 to better understand the trends.

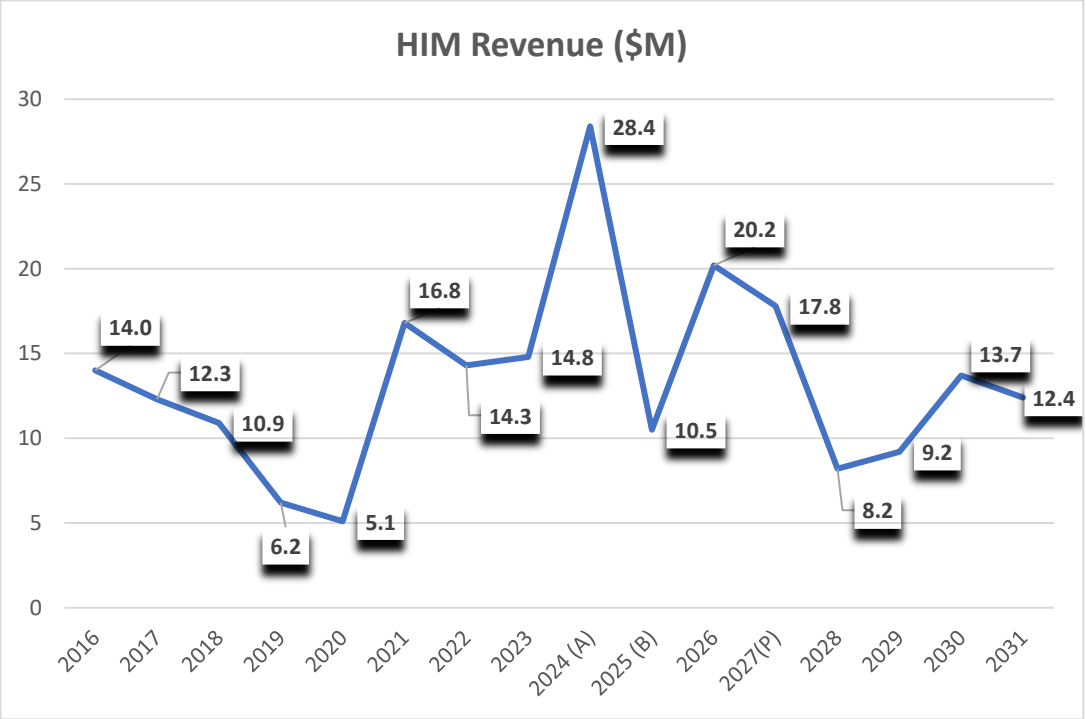

Chart 1 – HIM Revenue

Question(s):

a) Please explain the key driver(s) contributing to the HIM revenue volatility with almost a six-fold increase from 2020 to 2024 in actual revenues – $5.1 million (2020) to $28.4 million (2024) – followed by forecast revenues involving almost a three-fold decline to $10.5 million (2025) and then almost a two-fold increase to $20.2 million (2026).

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

b) Please explain why OPG is forecasting a significant decline in annual revenues of over $5 million per year during the IR term (with annual average forecast revenues during the five-year IR term at $12.3 million, while the annual average is $17.6 million over the five years before the IR term).

Response

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

a) The most significant driver of HIM revenue volatility is the magnitude and distribution of price spreads between on and off-peak periods in the real-time market and, after the implementation of the Renewed Market, also in the day-ahead market. These price spreads create opportunities for OPG to earn HIM revenue by following market signals. On and off-peak prices, and their relative deviation, are influenced by a variety of market conditions, including variability in supply and demand, intertie behaviour, and the impact of weather on electricity demand and hydroelectric inflows. Forecast HIM revenues are based on weather-normal market conditions and longer-term inflow trends and may differ from actual HIM revenues due to the cumulative impact of the actual values of these price drivers.

   A year-over-year analysis, including key drivers of HIM revenues for 2020 to 2026 is provided in Ex. G1-1-2, Sections 2.0, 3.0, and 4.0.

b) As described in Ex. L-E1-Staff-143, OPG inadvertently provided a forecast of HIM revenues for 2028-2031 in columns d)-k) for lines 15-21 in Ex. G1-1-2, Table 1. OPG will update the evidence to remove this information from the Application, as OPG maintains that it is not relevant under OPG's proposed hydroelectric rate-setting framework. The methodology relies on the 2027 test year to determine the base payment amounts that will be updated mechanistically each year by the proposed rate formula to determine the payment amounts for the outer years of the period (i.e., 2028-2031). Notwithstanding the foregoing, in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has provided the forecast of HIM revenues for 2028-2031 in Ex. L-A1-SEC-012, Attachment 1, Table 12, which has been provided pursuant to the Motions Resolutions letter filed on May 4, 2026. and an explanation of this forecast below.

   OPG's HIM revenue forecast of $17.8M for 2027 is in line with the annual average of $17.6M for the five years before the IR term.[1] The 2027 HIM revenue reflects OPG's forecast of more moderate, weather normalized price spreads relative to

[1] The five-year pre-IR average is based on actual HIM revenues for 2022 to 2024 and OPG's forecast for HIM revenues for 2025 and 2026.

recent years, which are expected to decrease also due to the impact of 1,132 MW of battery energy storage systems ("BESS") expected online by the end of 2027.[2, 3]

The forecast of HIM revenues for 2028-2031 maintains the use of weather normalized inputs. Price spreads for this period are forecasted to decrease further in part due to the in-service of an additional 1,784 MW of BESS expected in 2028.[4] BESS operations typically involve discharging during on-peak periods and charging during off-peak periods.[5] On-peak discharging can displace higher-cost marginal supply,[6] placing downward pressure on on-peak prices, while off-peak charging increases demand during lower-priced hours, placing upward pressure on off-peak prices. Collectively, BESS operation is expected to narrow the spread between on-peak and off-peak market prices and therefore reduce HIM revenues.

Price spreads are also impacted by changes in supply and demand, and variability in forecasted nuclear production over the 2028-2031 period.

[2] Per 882 MW in IESO Resource Adequacy Update May 9, 2024 and 250 MW for the Oneida Energy Storage Project. BESS reduces price spread by shifting energy from off-peak to on-peak.
[3] As discussed in Ex. L-G1-Staff-240, Ontario's battery storage fleet is projected to increase by 2,916 MW between 2025 and 2028.
[4] IESO Resource Adequacy Update May 9, 2024.
[5] IESO Energy Storage Backgrounder.
[6] IESO LT2 Backgrounder: December 2023.

CCC Interrogatory #097

Interrogatory

Reference:
Exhibit G2, Tab 1, Schedule 1, pp. 6-7

Preamble:

Direct costs for heavy water processing services are for estimated incremental direct labour costs attached to processing heavy water for Bruce Power at the TRF and direct labour (e.g., handling, testing, packaging) and other costs (e.g., shipping) attached to the provision of other services (e.g., loans, swaps, upgrading) to third parties.

Question(s):

a) How does OPG establish the price it charges to 3rd parties, including Bruce Power, for Heavy Water processing?

b) Please explain if and how the D2O Storage Facility is used to facilitate Heavy Water Processing.

c) To the extent that the D2O Storage Facility is used to facilitate Heavy Water Processing, please explain if and how the costs of the D2O Storage Facility are allocated to the costs recovered from third parties for heavy water processing.

d) Please provide a fully allocated pricing analysis of the heavy water processing service.

Response

a) Current heavy water processing revenue is earned from the provision of detritiation services to Bruce Power LP only and responses to follow are specific to that commercial relationship.

   OPG's current unit pricing for heavy water processing is set for a defined period based on a forecast of the heavy water processing volumes and costs. The unit price is determined on a forward-looking basis and includes provision for recovery of direct and allocated OM&A costs relating to the operations of the Tritium Removal Facility ("TRF") and a return of and on TRF related capital investments and, as discussed below, a portion of the Heavy Water Storage and Drum Handling Facility ("D2O Storage Facility"). The capital investment costs are straight line

depreciated over the respective useful lives and a cost on capital is applied on the undepreciated asset balance. The unit price calculation includes a true-up mechanism that adjusts for any over or under recovery from the previous period, based on actual usage, accounting for the tritium content of the heavy water processed, and costs.

As discussed in EB-2020-0290, the D2O Storage Facility was executed to meet two distinct needs – to support the Darlington Refurbishment Program, and to achieve operational improvement in heavy water processing.[1] The D2O Storage Facility capacity for operational improvement is used to facilitate heavy water processing by enabling greater storage of TRF feed and product to address gaps between TRF availability and the demand for tritium removal, including when the TRF is undergoing an outage, and facilitating a more flexible heavy water shipment schedule between stations.

b) OPG recovers a portion of D2O Storage Facility costs through the unit pricing charged to Bruce Power LP for heavy water processing, as described above. The calculation of Bruce Power LP's share of the D2O Storage Project's costs reflects the application of: (i) [redacted], being the determined allocation of the facility's capacity supporting heavy water management services; and (ii) the ratio of the quantity of heavy water processing services provided to Bruce Power LP by the TRF during the relevant period compared to OPG's internal usage of the TRF.[2]

c) OPG's heavy water processing pricing basis for the detririation services provided to Bruce Power LP is described in part a) above. This fully allocated current price of [redacted] is detailed in Chart 1 below.

[1] EB-2020-0290: Ex. D2-2-10, pp. 36-38; Tr. Vol. 2, pp. 17-20.
[2] EB-2020-0290: Ex. L-D2-02-SEC-091 and Ex. J2.8.

Chart 1 - Analysis of Current Heavy Water Processing Rate

	Cumulative Pricing Period Forecasted Amounts
Expenses	
Direct OM&A Costs	[redacted]
Allocated OM&A Costs	
Depreciation & Amortization	
Cost of Capital	
Total Heavy Water Processing Costs ($) (A)	
Heavy Water Production Forecast (kg) (B)	
Heavy Water Processing Price ($/kg) (A)/(B)	

[1] Excluding any true-up adjustments in respect of prior pricing period.

CCC Interrogatory #098

Interrogatory

Reference:
Exhibit G2, Tab 2, Schedule 1, Table 1

Preamble:

The noted tables compare the OEB-approved Bruce Lease related revenues and costs against the actual/budgeted revenues and costs from 2020 to 2026.

Question(s):

a) Please confirm that the entire net differential between the OEB forecast net revenue associated with the Bruce lease (i.e. as set out in Table 1) is subject to true up through the Bruce Net Lease Variance Account. If not confirmed, please explain which aspects of the net revenue are not ultimately trued up to actual through the account.

b) What incentive, if any, does OPG have to maximize the net revenue impact of the Bruce lease on customers?

Response

a) Confirmed.

b) OPG applies Bruce Lease net revenues to the revenue requirement for OPG's prescribed nuclear assets in accordance with sections 6(9), 6(10) and 6(10.1) of O. Reg. 53/05 and the OEB's previous decisions and orders. To the extent the Bruce Lease net revenues are positive, applying them against OPG's nuclear revenue requirement reduces it. If the Bruce Lease net revenues are negative, their application to OPG's nuclear revenue requirement serves to increase it. This treatment was indicated in the OEB's EB-2007-0905 decision (EB-2007-0905, Decision with Reasons, November 3, 2008, p. 111) and continued in all subsequent OPG proceedings.

A discussion of incentives, if any, to maximize the net revenue impact of the Bruce Lease is not relevant to the issues in this Application for the reasons set out in the OEB's decision in EB-2007-0905 (EB-2007-0905, Decision with Reasons, November 3, 2008, pp. 99-112) where the OEB held, among other things, that the Bruce Lease is an unregulated commercial contract and that "[t]he Board has no

authority to set or review the terms of the lease between OPG and Bruce Power" (p. 99).

SEC Interrogatory #202

Interrogatory

Reference:
G1-1-1, Table 1

Question(s):

With Laurentis Energy Partners ("Laurentis"):

a) Does Laurentis, or its subsidiaries, utilize current or former OPG nuclear employees for the purposes of its various nuclear consulting, project management, and technical services? If so, how does it compensate OPG for the use of these employees?

b) [Laurentis New Nuclear brochure, dated July 18, 2024, p.2] Please explain what Laurentis means when it says that it "leverages decades of nuclear power knowledge through its parent company, Ontario Power Generation (OPG)" and explain how it compensates the OPG regulated business for this knowledge.

c) What revenue from Laurentis is included in OPG's 2027 to 2031 Other Revenue Forecast?

Response

a) Yes, Laurentis Energy Partners ("LEP") may use existing OPG employees for purposes of providing its services. When this occurs, OPG recovers the associated costs from LEP, including allocated support costs in accordance with OPG's cost allocation methodology. Such costs are not included in OPG's proposed 2027-2031 revenue requirements. Former OPG employees do not form part of OPG's ongoing business.

b) As discussed in part (a) of this response, OPG is compensated by LEP for the use of its existing employees. OPG is not separately compensated for the knowledge the employees may possess based on their education, skills and/or past experiences.

c) Revenues from OPG's unregulated business (including LEP) are not included in the 2027-2031 Other Revenue forecast.

For clarity, there are also no costs associated with OPG's unregulated business (including LEP) included in the proposed 2027-2031 revenue requirements.

SEC Interrogatory #203

Interrogatory

Reference:
G2-1-1

Question(s):

With respect to isotope production, how does OPG determine which isotopes produced at Darlington or Pickering will be extracted and sold by OPG, or by Laurentis Energy Partners?

Response

The decision of whether to pursue isotope production is dependent on the level of investment and business risk associated with the production and the sales of isotopes as a separate commercial enterprise. For ventures that require investment and bear commercial risk beyond the ambit of electricity generation, Laurentis Energy Partners may be better placed to pursue those ventures.

Board Staff Interrogatory #243

Interrogatory

Reference:
Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 2
Ref 2: Exhibit F3 / Tab 2 / Schedule 1 / p. 1

Preamble:

At Reference 1, OPG notes that Cobalt-60 is a medical isotope and production at Pickering will cease over the IR term due to the refurbishment, with the final harvest expected in 2027. It also states that OPG is moving forward to produce Cobalt-60 at Darlington starting in 2028 and OPG is proposing to establish an asset service fee (ASF) associated with that production.

OPG notes in this Application that, in EB-2020-0290, OPG had discussed taking a different approach that involved bringing forward a "proposal involving revenues, operating costs and capital amounts for the production of Cobalt-60 at Darlington in the next nuclear payment amounts application".

At Reference 2, it states "The generating businesses, including DNNP, are charged an ASF for the use of the assets, which are included in the respective OM&A expenses in the Application."

Question(s):

a) Please explain why OPG is proposing a different approach involving the ASF, rather than the approach discussed in the EB-2020-0290 proceeding.

b) Please provide an explanation that compares how OPG recovers its costs under the two different approaches including the amount that would be recovered from consumers under each approach.

Response

a) and b)

The question misunderstands the evidence from EB-2020-0290 and the evidence in this Application. Specifically, the evidence in EB-2020-0290 stated that OPG would "bring forward a proposal *regarding* revenues, operating costs and capital amounts for the production of Cobalt-60 at Darlington in the next nuclear payment

amounts application."[1] (*emphasis added*). The evidence in this Application references that EB-2020-0290 evidence in similarly stating that "[i]n EB-2020-0290, OPG indicated it would bring forward a proposal regarding revenues, operating costs and capital amounts for the production of Cobalt-60 at Darlington in the next nuclear payment amounts application."[2]

In this Application, OPG has articulated its proposal regarding the revenues, operating costs and capital amounts for the production of Cobalt-60 at Darlington, which is to exclude these items from OPG's nuclear revenue requirement and instead reduce the revenue requirement by the corresponding asset service fees, the calculation of which is discussed in Ex. F3-2-1, p. 7, line 4 to p. 8, line 10. This approach is consistent with that applied for the production of Molybdenum-99 isotope and accepted by the OEB in EB-2020-0290 through the approval of the settlement proposal.

[1] EB-2020-0290, Ex. G2-1-1, p. 3, lines 3-4.
[2] Ex. G2-1-1, p. 2, lines 22-24.

Board Staff Interrogatory #244

Interrogatory

Reference:
Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 4
Ref 2: Exhibit G2 / Tab 1 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG explains that heavy water processing is comprised of tritium removal (detritiation) at the Tritium Removal Facility (TRF) and the TRF is reaching end of life. OPG is therefore undertaking the TRF Major Component Replacement Program, consisting of multiple projects over six outages between 2026-2038 (D2-T1-S3, section 3.1.3). OPG further states that heavy water processing is planned over the IR term based on TRF availability assumptions.

At Reference 2, the table indicates Heavy Water Sales & Processing (which is redacted) has historically accounted for the majority of Total Non-Energy Revenues and the forecast trend in the latter for the IR term appears to be consistent with the actual Total Non-Energy Revenues trend, except for 2027 where there is a significant decline from $42.9 million to $16.4 million and then increases back up to $43.5 million in 2028.

Question(s):

a) Please provide the TRF availability assumptions. For example, is 2027 the only year during the IR term that heavy water processing is expected to be impacted by the TRF Major Component Replacement Program?

Response

a) Expected TRF availability over the IR term considers planned TRF outage scheduling, inclusive of the Tritium Removal Facility Major Component Replacement program ("TRF MCR") requirements and the TRF maintenance cycle, and an operating capacity factor that accounts for recent TRF performance while anticipating a phased improvement in availability through the TRF MCR. An operating capacity factor of [redacted] is applied for the years [redacted] and [redacted] is applied for the years [redacted] Such operating capacity factors exclude the period of time when the TRF is in a planned outage.

The TRF is expected to be available in all years in the IR term, although the availability is impacted each year by the planned TRF outage scheduling. Such greatest impact on expected TRF availability occurs in 2027, as the TRF is scheduled to undergo a planned outage for the majority of the year to accommodate the corresponding TRF MCR scope. The outage impacts in the other years of the IR term are lower based on their planned scope and duration, with the 2029 year experiencing the second largest outage impact over the IR term.

Board Staff Interrogatory #245

Interrogatory

Reference:
Ref 1: Exhibit G2 / Tab 1 / Schedule 1 / p. 2
Ref 2: Exhibit F3 / Tab 2 / Schedule 1 / p. 1

Preamble:

At Reference 1, in relation to reactive support and voltage control (RSVC) service, OPG states forecast revenues over the IR term are expected to be zero under an agreement with the IESO. The reason provided for zero revenues is OPG only earns revenue "tied to production losses resulting from provision of the RSVC service outside the standard capability range of the respective resources". OPG further notes it is proposing to discontinue entries into the related Ancillary Revenues Variance Account sub-account since no revenues are expected and the relatively modest variance amounts historically settled through the sub-account.

At Reference 2, OPG explains that the 2026 budgeted RSVC revenues are higher than the OEB approved revenues due to higher utilization of this ancillary service than OPG had expected.

Question(s):

a) Please clarify what revenue "tied to production losses … outside the standard capability range" means within the context of providing RSVC service.

b) Did budgeted RSVC revenues exceed OPG expectations in 2026 under the current agreement with the IESO? If so, please explain why OPG expects zero revenues over the IR term.

c) Given the current agreement with the IESO ends in July 2028 and the IR term extends out to 2031, does OPG's expectation of continued zero revenues mean OPG expects to cease providing this service and will not enter into a new agreement with the IESO starting in August 2028?

d) If OPG does expect to enter into a new agreement with the IESO starting in August 2028, please explain why OPG plans do so if it expects no revenues (i.e., no utilization of RSVC service).

Response

a) Within the context of RSVC services, "revenue tied to production losses resulting from provision of RSVC service outside the standard capability range" refers to revenues associated with operations outside the range required by the connection requirements provided for in Chapter 4, Appendix 4.2 of the Market Rules. Specifically, to connect to the IESO-controlled grid, generators must be able to "continuously (i.e., dynamically) inject or withdraw reactive power at the high-voltage terminal of the main output transformer up to 33% of the applicable rated active power at all levels of active power, and at the typical transmission system voltage..." thereby establishing a "standard capability range".[1]

b) Yes, 2026 budgeted RSVC revenues exceed OPG expectations reflected in the 2026 OEB-approved amounts. [redacted]

c) No. OPG's expectation of zero RSVC revenue during the IR term does not mean that OPG expects to cease providing RSVC service. It also does not mean that OPG will not enter into a subsequent agreement with the IESO after July 2028. [redacted]

d) OPG expects its RSVC agreement with the IESO, which includes both its nuclear and hydroelectric facilities, will be renewed beyond July 2028. OPG notes that the Market Rules direct the IESO to obtain reactive power resources to maintain reactive support service and voltage control service in accordance with all applicable reliability standards and that reactive support service and voltage control service shall be made available by market participants. While OPG does not expect any resulting revenues from its nuclear facilities during the IR term, it expects to receive revenues from its regulated hydroelectric facilities for speed-no-load and condense mode of operations.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Renewed-Market-Rules-and-Manuals/market-rules/ieso-mr-chapter0-4-appx.pdf