OTHER REVENUES – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to present the forecast of revenues for the 2027 test year from sources other than energy production ("Other Revenues") from OPG's regulated hydroelectric generating facilities and to explain the proposed treatment of these revenues.

The forecast of Other Revenues is included as an offset in the calculation of OPG's 2027 revenue requirement for the regulated hydroelectric facilities presented in this Application.

2.0 OVERVIEW

Other Revenues earned by OPG's regulated hydroelectric facilities are revenues associated with ancillary services,[1] segregated mode of operation ("SMO"), water transactions, the Installed Capacity ("ICAP") market, and Clean Energy Credits ("CEC"). Other Revenues also include the Hydroelectric Incentive Mechanism ("HIM") Revenue Requirement Adjustment.

Consistent with the methodology approved in EB-2013-0321, differences between forecast and actual revenues associated with ancillary services, including impacts of future contract negotiations with the IESO, are recorded in the Ancillary Service Net Revenue Variance Account – Hydroelectric Sub Account (Ex. H1-1-1, Section 5.2).

The treatment of potential impacts of the IESO's Market Renewal Program ("Renewed Market") is discussed below as part of the detailed description of each Other Revenues forecast.

Exhibit G1-1-1, Table 1 presents the Other Revenues associated with the regulated hydroelectric assets for the period 2016-2027. Where possible, Other Revenues are tracked and recorded on a facility-specific basis. For the purposes of this exhibit, only those revenues that are directly associated with the regulated generation facilities have been included.

[1] Ancillary Services include black start capability, operating reserve ("OR"), reactive support/voltage control, and Regulation Service (formerly referred to as Automatic Generation Control).

3.0 ANCILLARY SERVICES

Under the IESO Market Rules, ancillary service suppliers receive compensation for costs associated with supplying ancillary services. These include out-of-pocket costs, lost production costs and opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable.

Ancillary service revenues are tracked at the station level and only those revenues related to the regulated facilities are included in this exhibit.

Ancillary service revenue forecasts are expected to remain largely unaffected in the Renewed Market. Aside from OR, ancillary service revenues are generally determined by system needs and operating conditions rather than by market price signals or other changes that were introduced in the Renewed Market. Any variances from the forecast of revenues will be recorded and captured in the Ancillary Services Net Revenues Variance Account.

3.1 Black Start Capability

Black start capability, as defined in the Market Rules, refers to the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid.

Black start revenues are paid to OPG on a fixed basis annually and are not impacted by the implementation of the Renewed Market.

OPG forecasts revenues for black start capability for the 2027 test year on the same basis as the terms of the IESO-OPG Procurement of Certified Black Start Facilities Agreement effective June 1, 2021-May 31, 2026.

3.2 Reactive Support/Voltage Control Service

Under the IESO Market Rules, Reactive Support and Voltage Control services (“RSVC”) refer to services provided by a market participant to allow the IESO to maintain the reactive power and voltage levels required by the IESO-controlled grid.

RSVC is not scheduled or settled based on market price and as a result is not impacted by the implementation of the Renewed Market.

OPG forecasts revenues for RSVC for the 2027 test year per the terms of the IESO-OPG agreement for RSVC service effective August 1, 2025-July 31, 2028.

3.3 Regulation Service

As defined in the IESO Market Rules, Regulation Service refers to the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between the demand from load and the supply from generation facilities.

In the Legacy Market (referring to the market prior to the Renewed Market), the Regulation Service contract provided payments related to OR-related opportunity losses. In the Renewed Market these losses are compensated as Real-Time OR Make-Whole Payments and captured within OR revenues as described in Section 3.4. OPG forecasts revenues for Regulation Service for the 2027 test year as per the terms of the IESO-OPG Procurement of Regulation Services Agreement effective February 1, 2023-January 31, 2034.

3.3.1 <u>Niagara Hydrogen Centre</u>

Currently, the provision of Regulation Service at Sir Adam Beck 2 GS requires turbine modulation that can result in a portion of water flows not being utilized by OPG for electricity production (“Unutilized Water”).

The Niagara Hydrogen Centre (“NHC”), to be constructed and operated by Atura H2 L.P and expected to enter service in 2026, will make use of this otherwise Unutilized Water. Specifically, the NHC’s electrolyzer will produce low-carbon hydrogen using electricity generated behind the meter at the Sir Adam Beck 2 GS facility from water that generally would not be used for electricity production. The Regulation Service agreement incorporates provisions related to the NHC and is consistent with the expectations set out in the Ministry of Energy's letter to the IESO dated December 9, 2022.[2]

3.4 Operating Reserve

OPG's regulated hydroelectric fleet offers OR as an ancillary service to the IESO. Operating Reserve refers to the capacity that can be called upon in short notice by the IESO to replace scheduled energy supply that is unavailable because of an unexpected outage or to augment scheduled energy due to unexpected demand or other contingencies. In the Renewed Market, the IESO procures OR in both day-ahead and real-time for all three categories of OR.[3]

Other changes to OR introduced in the Renewed Market include a single OR schedule in both the Day-Ahead Market and the Real-Time Balancing Market, both of which are settled on Locational Marginal Prices ("LMP"), and the use of an OR Demand Curve during periods of scarcity. As OR CMSCs are eliminated, the Renewed Market uses Day-Ahead and Real-Time OR Make Whole Payments to ensure revenue sufficiency in cases of uneconomic OR scheduling. Chart 1 provides a summary of OR revenues received by OPG's regulated hydroelectric facilities during the first five months in the Renewed Market.

Chart 1 – OR Market Revenues Since Market Renewal Implementation

	DA OR Revenues	**RT OR Revenues**	**DA OR MWP**	**RT OR MWP**	**Total OR Revenues**
Month	$M	$M	$M	$M	$M
May	8.1	(0.8)	0.1	1.8	9.1
June	6.2	(6.1)	0.0	3.2	3.4
July	7.7	(3.5)	0.0	2.3	6.5
August	3.3	(0.3)	0.0	0.5	3.5
September	1.1	(0.3)	0.0	0.5	1.3

[2] Smith, T, *Letter to Ms. Lesley Gallinger regarding the Niagara Hydrogen Centre and Regulation Service Contract*, December 9, 2022 <https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20221209.pdf>.

[3] 10-minute synchronized (spinning) reserve, 10-minute non-synchronized (non-spinning) reserve, and 30-minute reserve (non-synchronized).

As described in Ex. E1-2-1, the ability to draw conclusions from data in the Renewed Market is limited due to (i) short duration the renewed market has been in operation; (ii) participants learning how the Renewed Market works and adjusting their strategies; and (iii) experience in only two seasons.[4] As such, OPG does not expect the observed increase in average total OR revenues in the Renewed Market as compared to the Legacy Market to sustain into the future. The higher OR revenues in the first few months of the Renewed Market and subsequent declining trend could be explained by a combination of system conditions as well as a maturation of participant behavior. OPG notes that its total OR revenues in the month of September of $1.3M are in line with its historical monthly average of $1.2M for the 2020-2024 period. As discussed in Ex. E1-2-1, Section 6.1, the IESO will be making targeted changes to Market Rules to address specific circumstances under which unwarranted MWPs are calculated. This change is expected to result in lower MWPs, including OR MWPs. Additionally, in OPG's view the expected addition of approximately 3,000 MW of battery energy storage facilities between 2025-2028 will put downward pressure on OR prices beyond those experienced in the Legacy Market.

Considering the insufficient data from a steady-state, Renewed Market, OPG's OR revenue forecast for the 2027 test year is based primarily on historical volumes and forecasted OR market prices inclusive of the expected price dampening impact of battery energy storage facilities expected in the coming years.

4.0 SEGREGATED MODE OF OPERATION

Segregated Mode of Operation is defined in the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity. R.H. Saunders GS and Chats Falls GS, both in the Eastern Region, are the only prescribed hydroelectric facilities that are capable of entering into SMO. As a result, all SMO revenues are included within this exhibit.

[4] IESO, "Update on Renewed Market Performance and Operations", August 21, 2025 <https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf>.

Segregated Mode of Operation is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties. Forecast market prices in Ontario and surrounding markets are the economic drivers considered when deciding whether to engage in a SMO transaction.

Segregated Mode of Operation net revenues are calculated by subtracting the incremental costs associated with these transactions from the SMO revenues received. The incremental costs incurred in transacting SMO consist of export fees, transmission losses between generator source and point of delivery, production losses during the switching process between control areas, and the costs associated with the non-regulated trading business to carry out these transactions.

The Renewed Market introduces two main changes that affect SMO: IESO transaction approval timelines and market prices. Under the new Day-Ahead Market framework, the IESO's approval process for SMO transactions is more restrictive than it was in the Legacy Market. While this change is expected to reduce the number of SMO transactions OPG can conduct, uncertainty related to prevailing market prices in the Renewed Market will also impact SMO revenue.

Based on the limited experience OPG has had in the Renewed Market, OPG has forecast 2027 SMO revenues on the historical five-year average of SMO revenues and has not made adjustments for market prices. This approach smooths out annual variability in performance and addresses the inherent challenges of producing forward forecasts with limited experience in the Renewed Market.

5.0 WATER TRANSACTIONS

The New York Power Authority ("NYPA") and OPG are responsible for operating hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to an agreement between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total volume of water available for generation under the relevant international treaties.

The Water Transfer agreements between OPG and NYPA allow one entity the opportunity to extract the potential energy from the other entity's share of water (i.e., referred to as a "Water Transfer") in order to optimize the use of available water. Water Transfers could be done at the request of the sender, receiver, or the Niagara River Control Centre.

The transferred water is used to generate electricity that is then sold into the respective entity's electricity market (the IESO-administered market if OPG is the receiving entity, or the New York Independent System Operator ("NYISO") administered market if NYPA is the receiving entity). The water transfer agreements specify how the benefits and costs associated with the types of water transfer are shared between entities. Water Transfers only pertain to regulated hydroelectric facilities. As a result, all Water Transaction revenues are included within this Exhibit.

The volume of Water Transactions completed in a year is not impacted by the implementation of the Renewed Market. Water Transaction revenues, however, are impacted by market prices. To the extent the Renewed Market leads to higher or lower average market prices than the Legacy Market, there will be a corresponding impact on Water Transaction revenues.

To calculate net water transfer revenues, accommodation charges and gross revenue charges attributable to these transactions are subtracted from the gross water transfer revenues. Based on the limited experience OPG has had in the Renewed Market, OPG has forecast the 2027 water transfer revenues based on the historical five-year average of net water transfer revenues and has not made adjustments for market prices. This approach smooths out annual variability in the volume of water transactions and addresses the inherent challenges of producing forward forecasts with limited experience in the Renewed Market.

6.0 CAPACITY EXPORT TRANSACTIONS

Installed Capacity market transactions are permitted under the IESO Market Rules when a market participant has Ontario-based generating capacity that the IESO has determined to be surplus to Ontario's reliability and planned resource adequacy requirements. The IESO currently has a capacity export agreement in place with the NYISO along with a process in place to enable market participants to participate in the NYISO capacity market. OPG currently has three aggregates at the Sir Adam Beck 2 GS[5] registered to participate in the NYISO capacity market and has been participating in this market since 2016.

The amount of capacity that can be sold by OPG to NYISO (and therefore revenues earned) depends on a number of factors that are not within OPG's control and are difficult to forecast. These factors include, but are not limited to, the amount of capacity the IESO approves to be released from the Ontario market, the external capacity rights NYISO allocates to Ontario, and capacity market clearing prices in the NYISO market.

The ICAP net revenues are calculated by subtracting the incremental costs associated with these transactions from the gross ICAP revenues received. The incremental costs incurred in ICAP transactions include auction participation costs and the cost of meeting NYISO ICAP compliance obligations. The ICAP revenues only pertain to regulated hydroelectric facilities. As a result, all ICAP revenues are included within this Exhibit.

The ICAP revenues are not influenced by Ontario market prices and as a result are not impacted by the Renewed Market. These revenues are determined by two external factors: the capacity market clearing prices established in New York's capacity auctions, and the amount of Ontario capacity that the IESO releases to participate in that market. The IESO's decision on how much capacity to release is based on Ontario's resource adequacy requirements, ensuring that domestic reliability needs are met before any export is permitted. As a result, ICAP revenues reflect New York capacity market outcomes and IESO capacity release decisions, rather than Ontario market price dynamics.

OPG forecasts ICAP net revenues for the 2027 test year based on the historical five-year average of ICAP net revenues. This approach smooths out annual variability in performance and addresses the inherent challenges of producing accurate forward forecasts.

[5] There are three aggregated generation units at the facility registered with the IESO for export capacity to NYISO, each comprising a pair of generators: Generators 11 and 12, Generators 13 and 14, and Generators 17 and 18.

7.0 HIM REVENUE REQUIREMENT ADJUSTMENT

OPG forecasts HIM net revenues by applying market and operational information to the OEB-approved HIM formulas. Key inputs include Ontario supply and demand forecasts, LMP projections, water flow forecasts, and operational information for OPG's regulated hydroelectric fleet. OPG's proprietary model also incorporates external sources and market forecasts, to form the basis of OPG's HIM projections.

Within its model, hydroelectric resources are scheduled according to expected water flows and operating limits, following Ontario's demand profile net of baseload nuclear, wind, and solar generation. When electricity prices are anticipated to fall below the Gross Revenue Charge, certain hydro units are considered uneconomic, leading to forecast Surplus Baseload Generation spill. These conditions inform both the expected incentives for time-shifting water and the calculation of unintended benefits under the HIM.

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.[6] 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. Overall, OPG expects its forecast 2027 HIM net revenue, which is an increase from OPG's HIM net revenues in the Legacy Market, to adequately capture OPG's revenues in a mature Renewed Market.

OPG proposes to continue to include a revenue offset equal to 50% of forecast annual HIM net revenues. This treatment is consistent with the HIM Revenue Requirement Adjustment established in EB-2010-0008 and EB-2013-0321.

[6] The model is based on average price spreads and does not fully reflect the ability of the PGS to respond to significant short-run differences in hourly prices.

OPG is also proposing to eliminate the sharing of HIM net revenues that exceed the HIM revenue forecast as described in Ex. E1-2-1, Section 5.0.

8.0 CLEAN ENERGY CREDITS

Within the Ontario CEC market, OPG sells environmental attributes associated with its regulated hydroelectric and nuclear generation facilities.

On March 29, 2023, the Province of Ontario announced the launch of the Clean Energy Credit Registry, to be administered by the IESO with the stated objective being to boost Ontario's competitiveness in attracting investment and jobs.[7] As part of the announcement, the Province noted that proceeds from the sale of CECs held by the IESO and OPG would be directed to the government's Future Clean Electricity Fund, which will "help keep costs down for electricity ratepayers by supporting the development of new clean energy projects as the province builds out our grid to meet the demands of a growing population and economy, as well as the electrification of transportation and industry".[8]

As part of the accompanying O. Reg 39/23 *Clean Energy Credits*, under section 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. As such, the Province has already legislated the amount to be returned to the benefit of ratepayers through investments of the Future Clean Electricity Fund. OPG proposes to retain the remaining 20% of net revenues from the sale of CECs to provide an appropriate incentive for the organization to continue pursuing CEC sales.

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[7] Province of Ontario, News Release: Ontario launches Clean Energy Credit Registry to Boost Competitiveness and Attract Jobs, March 29, 2023 <https://news.ontario.ca/en/release/1002876/ontario-launches-clean-energy-credit-registry-to-boost-competitiveness-and-attract-jobs>.
[8] *Ibid*.

Numbers may not add due to rounding.

Table 1
Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Ancillary Services[1]**	70.1	78.7	70.5	71.8	55.5	50.1	71.6	62.3	58.5	56.1	51.5	49.1
2	**Segregated Mode of Operation[2]**	0.4	3.1	2.7	0.0	0.0	0.0	8.0	0.4	1.2	1.9	1.9	1.9
3	**Water Transactions[3]**	1.1	0.9	1.6	0.9	0.2	0.6	0.6	1.6	3.5	1.3	1.3	1.3
4	**Capacity Exports[4]**	0.1	0.6	2.3	0.2	0.0	0.4	0.0	1.5	3.0	1.0	1.0	1.0
5	**Total Ancillary Services**	71.8	83.2	77.1	72.8	55.7	51.1	80.2	65.8	66.4	60.3	55.8	53.3
6	**HIM Revenue**	14.0	12.3	10.9	6.2	5.1	16.8	14.3	14.8	28.4	10.5	20.2	17.8
7	**Total of Other Revenues**	85.8	95.5	88.0	79.0	60.7	67.8	94.5	80.6	94.7	70.9	76.0	62.2

Notes:

1 Ancillary Services related to regulated hydroelectric facilities are discussed in Ex. G1-1-1, Section 3.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).

4 2027 Total of Other Revenues includes 50% of the HIM Revenue forecast as described in Ex. G1-1-1, Section 7.

COMPARISON OF OTHER REVENUES
REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of Other Revenues for OPG's regulated hydroelectric facilities based on actuals for 2016-2024 and forecast for 2025-2027. Corresponding Other Revenues are provided on Ex. G1-1-2, Table 1.

The treatment of potential impacts of the IESO's Market Renewal Program ("Renewed Market") are described within Ex. G1-1-1. The expected impacts of the Market Renewal Program have generally not resulted in any material annual variances in the forecast of Other Revenues.

Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for its regulated hydroelectric business below, for the period 2016-2024. As there is no OEB-approved other revenues information for 2015 onwards, OPG has only provided year-over-year variance analysis for the historical (2016-2024), bridge (2025-2026), and test year (2027).

2.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR

2027 Plan versus 2026 Budget

The 2027 Plan Hydroelectric Incentive Mechanism ("HIM") revenues are expected to be $2.4M lower than 2026 Budget due to lower average price spreads forecasted for most of 2027 when compared to 2026.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Budget versus 2025 Budget

2026 Budget HIM revenues are expected to be $9.7M higher than 2025 Budget due to higher average forecast Locational Marginal Prices in 2026 compared to 2025.

2025 Budget versus 2024 Actual

The 2025 Budget HIM revenues are expected to be $17.8M lower than 2024 Actual due to lower average budgeted price spreads in 2025 compared to actual 2024 price spreads.

The 2025 Budget WT revenue is expected to be $2.2M lower than 2024 Actual. The 2025 Budget is established based on the average of the 2020-2024 actuals.

The 2025 Budget ICAP revenue is expected to be $2.0M lower than 2024 Actual. The 2025 Budget is established based on the average of the 2020-2024 actuals.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2024 Actual versus 2023 Actual

The 2024 Actual HIM revenue is $13.6M higher than 2023 Actual due to higher average price spreads and lower inflows during freshet which lead to a lower unintended benefit adjustment in 2024 compared to 2023.

The 2024 Actual WT revenue is $1.9M higher than 2023 Actual due to lower unit availability at R.H. Saunders GS, resulting in more water available to transfer to New York Power Authority ("NYPA").

The 2024 ICAP revenue is $1.5M higher than 2023 Actual mostly due to OPG clearing New York Independent System Operator's ("NYISO") capacity auction for more commitment months in 2024 compared to 2023.

2023 Actual versus 2022 Actual

The 2023 Actual Ancillary Services revenue is $9.3M lower than 2022 Actual mostly due to lower Operating Reserve ("OR") and Regulation Service revenues.

The 2023 Actual SMO revenue is $7.7M lower than 2022 Actual due to lower energy prices in 2023 coupled with decreased volume of SMO transactions.

The 2023 Actual ICAP revenue is $1.5M higher than 2022 Actual mostly due to OPG clearing NYISO's capacity auction for more commitment months in 2023 compared to 2022.

The 2023 Actual WT revenue is $1.0M higher than 2022 Actual due to decreased unit availability at R.H. Saunders GS in 2023, resulting in higher water availability to NYPA.

There are no reportable variances for HIM revenues in 2023 Actual vs. 2022 Actual.

2022 Actual versus 2021 Actual

2022 Actual Ancillary Services revenue is $21.5M higher than 2021 Actual. While Reactive Support and Voltage Control ("RSVC") revenues in 2022 were lower due to lower system utilization of the service, there was a net increase in 2022 ancillary revenues due to OR and Regulation Service revenues. The OR revenues increased as a result of significantly higher OR prices. The Regulation Service revenues increased mainly due to higher production costs associated with providing the service.

The SMO transactions resumed in 2022 following the COVID-19 pandemic. The SMO revenues in 2022 reached $8.0M which is higher than achieved in trailing historical years. In 2022 demand was higher than typical due to colder than normal winter weather, coupled with higher energy prices in Québec and Ontario. These higher energy prices are due to strong natural gas demand in 2022 driven from the conflict in Ukraine.

The 2022 Actual HIM revenue is $2.5M lower than 2021 Actual due to higher average off-peak HOEP in 2022 compared to 2021.

2021 Actual versus 2020 Actual

The 2021 Actual HIM revenue is $11.7M higher than 2020 Actual due to higher average price spreads in 2021 compared to 2020.

The 2021 Actual Ancillary Services revenue is $5.4M lower than 2020 Actual predominantly due to lower OR and Regulation Service revenues partially offset by higher RSVC revenues.

There are no reportable variances for SMO, WT, and ICAP revenues in 2021 Actual vs. 2020 Actual. SMO revenues for both years were $0M primarily due to lack of commercial opportunity resulting from the COVID-19 pandemic.

5.0 PERIOD-OVER-PERIOD CHANGES – EXTENDED HISTORICAL YEARS

Pursuant to the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included four additional years of historical data.

2020 Actual versus 2019 Actual

The 2020 Actual Ancillary Services revenue is $16.3M lower than 2019 Actual primarily due to lower Regulation Service revenues, as a result of new contract terms with the IESO.

2020 Actual HIM revenue is $1.1M lower than 2019 Actual due to lower average price spreads in 2020 compared to 2019.

2019 Actual versus 2018 Actual

The 2019 Actual HIM revenue is $4.7M lower than the 2018 Actual due to lower average price spreads in 2019 compared to 2018.

The 2019 Actual SMO revenue is $2.7M lower than 2018 Actual. There were no net revenues for 2019 due to lack of commercial opportunity resulting from the COVID-19 pandemic.

The 2019 Actual Capacity Exports revenue is $2.2M lower than 2018 Actual due to a decrease in the amount of capacity clearing the NYISO capacity auction in 2019.

2018 Actual versus 2017 Actual

The 2018 Actual Ancillary Services revenue is $8.1M lower than 2017 Actual mostly due to lower OR and RSVC revenues.

The 2018 Actual ICAP revenue is $1.7M higher than 2017 Actual due to more capacity commitments being made to NYISO.

The 2018 Actual HIM revenue is $1.4M lower than 2017 Actual due to lower average price spreads in 2018 compared to 2017.

2017 Actual versus 2016 Actual

The 2017 Actual Ancillary Services revenue is $8.5M higher than 2016 Actual due to higher Regulation Service, OR, and RSVC revenues.

The 2017 Actual SMO revenue is $2.7M higher than 2016 Actual due to higher energy prices in 2017 compared to 2016.

The 2017 Actual HIM Revenue is $1.7M lower than 2016 Actual due to higher inflows throughout the freshet and summer months of 2017, which lead to a higher unintended benefit adjustment when compared to 2016.

Table 1
Comparison of Other Revenues - Regulated Hydroelectric ($M)

Line No.	Business Unit	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Ancillary Services**[1]	70.1	8.5	78.7	(8.1)	70.5	1.3	71.8	(16.3)	55.5	(5.4)	50.1
2	**Segregated Mode of Operation**[2]	0.4	2.7	3.1	(0.4)	2.7	(2.7)	0.0	(0.0)	0.0	0.0	0.0
3	**Water Transactions**[3]	1.1	(0.3)	0.9	0.7	1.6	(0.7)	0.9	(0.7)	0.2	0.4	0.6
4	**Capacity Exports**[4]	0.1	0.4	0.6	1.7	2.3	(2.2)	0.2	(0.2)	0.0	0.4	0.4
5	**Total Ancillary Services**	71.8	11.4	83.2	(6.1)	77.1	(4.3)	72.8	(17.2)	55.7	(4.6)	51.1
6	**HIM Revenue**	14.0	(1.7)	12.3	(1.4)	10.9	(4.7)	6.2	(1.1)	5.1	11.7	16.8
7	**Total of Other Revenues**	85.8	9.7	95.5	(7.5)	88.0	(9.0)	79.0	(18.3)	60.7	7.1	67.8

Line No.	Business Unit	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
8	**Ancillary Services**[1]	50.1	21.5	71.6	(9.3)	62.3	(3.7)	58.5	(2.4)	56.1	(4.6)	51.5
9	**Segregated Mode of Operation**[2]	0.0	8.0	8.0	(7.7)	0.4	0.9	1.2	0.7	1.9	0.0	1.9
10	**Water Transactions**[3]	0.6	0.0	0.6	1.0	1.6	1.9	3.5	(2.2)	1.3	0.0	1.3
11	**Capacity Exports**[4]	0.4	(0.4)	0.0	1.5	1.5	1.5	3.0	(2.0)	1.0	0.0	1.0
12	**Total Ancillary Services**	51.1	29.1	80.2	(14.4)	65.8	0.5	66.4	(6.0)	60.3	(4.6)	55.8
13	**HIM Revenue**	16.8	(2.5)	14.3	0.5	14.8	13.6	28.4	(17.8)	10.5	9.7	20.2
14	**Total of Other Revenues**	67.8	26.6	94.5	(13.9)	80.6	14.2	94.7	(23.9)	70.9	5.1	76.0

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
15	**Ancillary Services**[1]	51.5	(2.4)	49.1
16	**Segregated Mode of Operation**[2]	1.9	0.0	1.9
17	**Water Transactions**[3]	1.3	0.0	1.3
18	**Capacity Exports**	1.0	0.0	1.0
19	**Total Ancillary Services**	55.8	(2.4)	53.3
20	**HIM Revenue**	20.2	(2.4)	17.8
21	**Total of Other Revenues**[4]	76.0	(4.8)	62.2

Notes:
1. Ancillary Services related to regulated hydroelectric facilities are discussed in Ex. G1-1-1, Section 3.
2. Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.
3. Water Transactions revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).
4. 2027 Total of Other Revenues includes 50% of the HIM Revenue forecast as described in Ex. G1-1-1, Section 7.

NUCLEAR NON-ENERGY REVENUES

1.0 PURPOSE

This evidence describes OPG's non-energy revenue derived from its nuclear operations, the regulatory treatment of these revenues and the forecast of nuclear non-energy revenues (net of related costs) for the IR term. There are no non-energy revenues that are forecast to be derived from the DNNP facilities during the IR term.

2.0 OVERVIEW

OPG's actual and planned nuclear non-energy revenues (net of related costs) for the period 2020-2031 are presented in Ex. G2-1-1, Table 1. For the IR term, these amounts are forecast to be $6.3M for 2027, $32.7M for 2028, $13.8M for 2029, $13.5M for 2030, and $23.6M for 2031. The revenues during the IR term are associated with isotope sales (Cobalt-60 at Pickering and tritium) and heavy water sales and processing. As in prior OPG applications, the forecast of such nuclear non-energy revenues for the IR term is included as an offset in the calculation of OPG's nuclear revenue requirements.

Isotope sales revenues fluctuate over the historical and bridge years and into the IR term due to the nature of outage work and timing of isotope harvesting. Isotope sales change year over year due to the scheduling of the Cobalt harvest windows, with sales of the final harvest to be produced before the Pickering refurbishment window expected to occur in 2027. Changes in heavy water sales and processing year over year are due to production fluctuations at the Tritium Removal Facility ("TRF") which are based on required outages as well as pricing assumptions. Isotope sales are discussed in Section 3.1 below and heavy water sales and processing revenues are discussed in Section 3.2 below. The related costs are discussed in Section 4.0.

Excluding ancillary services revenues and before the upward adjustment in the forecast revenues per the OEB-approved settlement proposal, OPG's nuclear non-energy revenues (net of related costs) are $25.6M lower over the 2022-2026 period compared to OPG's EB-2020-0290 forecast. Ancillary services revenues are discussed in Section 3.3 below.

3.0 NUCLEAR NON-ENERGY REVENUE SOURCES

3.1 Isotope Sales

3.1.1 Cobalt-60 Production at Pickering

Cobalt-60 is a critically important medical isotope used for radiation therapy, sterilization of medical equipment, food irradiation and specialized industrial uses. OPG currently produces Cobalt-60 at Pickering (Units 6, 7, and 8) for use in the sterilization of surgical and medical supplies. OPG sells Cobalt-60 to Nordion (Canada) Inc., under a long-term agreement that currently expires after the sale of the final harvest to be produced before the Pickering refurbishment window.

Sales volumes are constrained by OPG's ability to produce Cobalt-60. The direct costs and other support costs for this activity are discussed in Section 4.0 below. There is no Cobalt-60 production at Pickering during the IR term with Units 5-8 scheduled to enter refurbishment, with sales of such final harvest expected to occur in 2027. Cobalt-60 production may restart following the refurbishment, pending technical, operational and economic feasibility reviews and implementation of required capital expenditures. Any associated revenues would occur outside of the IR term and OPG would bring forward a proposal regarding their treatment at that time. The annual revenues up to 2027 fluctuate primarily due to harvesting of Cobalt-60 being tied to Pickering's outage schedule.

3.1.2 Cobalt-60 Production at Darlington

In 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.[1]

OPG is moving forward with the opportunity to produce Cobalt-60 at Darlington with the first harvest and corresponding sale expected in 2028. Neither the costs of the modifications made at Darlington to enable this production nor the associated ongoing operating costs are included in OPG's rate base or revenue requirement. Consistent with OPG's approach to the production of the Molybdenum-99 isotope accepted by the OEB in EB-2020-0290 through the approval of

[1] EB-2020-0290, Ex. G2-1-1, Section 3.1.1.1, pp. 2-3.

a settlement proposal[2] (as outlined in EB-2020-0290, Ex. F3-1-4, Section 4.0) and validated by Elenchus Research Associates (Ex. F3-1-4, Attachment 1, p. 23), OPG is proposing to establish an asset service fee associated with the production of Cobalt-60 at Darlington that would reduce OPG's nuclear revenue requirement. Details regarding such asset service fees and OPG's cost allocation methodology can be found in Ex. F3-2-1 and Ex. F3-1-4, respectively. The proposed fees are included as a reduction to the asset service fees shown in Ex. F3-2-1, Table 2.

3.1.3 Tritium Sales

Tritium is a by-product of electricity generation using Canadian Deuterium Uranium ("CANDU") technology. It is produced by the irradiation of heavy water. In order to stay within specified limits, and to lower radiation exposure to workers and the environment, tritium is removed from the heavy water via the TRF.

OPG has entered into short-term contracts to sell tritium to government-approved and licensed organizations. Commercial use of tritium includes safety and security products like land-mine markers and emergency exit signs, tritium labeled chemicals for medical research and research into future power sources.

Tritium sales have been relatively stable over time, with some variation due to competition, fluctuating demand and variations in the value of the Canadian dollar. Total revenues from isotope sales over the period 2020-2031 are shown in Ex. G2-1-1, Table 1. After the sale of the final harvest of Cobalt-60 from Pickering in 2027, the isotope revenues reflect forecast tritium sales. The direct costs and other support costs are described in Section 4.0 below.

Helium-3 is a byproduct of tritium decay. Laurentis Energy Partners, an unregulated subsidiary of OPG, is continuing to pursue investment in new technologies for the purpose of extracting Helium-3 located at Darlington. New and innovative equipment is required for the extraction. Neither such equipment, owned and funded by OPG's unregulated subsidiary, nor the extraction process impact OPG's ability to generate electricity or sell tritium. The costs of the

[2] Decision and Order, EB-2020-0290, November 15, 2021, Schedule A, pp. 41-43.

equipment and the extraction are not included in OPG's rate base or revenue requirement. OPG has an agreement in place with its subsidiary, supported by OPG's cost allocation methodology, which ensures an appropriate attribution of associated operating costs to the subsidiary.

3.2. Heavy Water Sales and Processing

Heavy water is a manufactured product required for CANDU reactor operations. Heavy water is required as a moderator for sustaining nuclear reactions and as a heat transport medium in CANDU nuclear reactors.

3.2.1 Heavy Water Sales

OPG previously sought opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG's current and future needs (including contractual obligations to Bruce Power). This surplus makes up the sales pool inventory.

Based on current assessment, the sales pool has zero inventory of non-tritiated heavy water available for sale. As such, no commercial transactions of non-tritiated heavy water are expected over the IR term. Planned total revenues for heavy water sales and processing over the period 2020-2031 are shown in Ex. G2-1-1, Table 1.

3.2.2 Heavy Water Processing

Heavy water processing is primarily comprised of tritium removal (detritiation) at the TRF. The bulk of the heavy water processing revenue is earned from the provision of detritiation services to Bruce Power. Opportunities to provide detritiation services to others are limited because of storage and capacity restrictions at the TRF. The TRF is reaching its design end of life and OPG is undertaking the TRF Major Component Replacement Program, consisting of multiple projects over six outages between 2026-2038 (Ex. D2-1-3, Section 3.1.3). The forecast of heavy water processing over the IR term is based on TRF availability assumptions that take into account this work. As a result, revenues fluctuate from year to year. Provision of detritiation services is also affected by the ability to ship heavy water to the TRF.

On occasion, OPG is able to lease/loan and sell small quantities of heavy water to third parties; revenues from these transactions are also recorded under heavy water processing as “heavy water services”. Planned total revenues for heavy water sales and processing over the period 2020-2031 are shown in Ex. G2-1-1, Table 1. Cost of goods sold and other support costs are described in Section 4.0 below.

3.3 Ancillary Services

OPG’s nuclear assets are able to supply the IESO with reactive support and voltage control service (“RSVC”). Reactive support service allows the IESO to maintain the reactive power levels required by the IESO-controlled grid. Voltage control service allows the IESO to maintain the voltage levels required by the IESO-controlled grid.

OPG forecasts revenues for RSVC for 2027-2031 as per the terms of the agreement with the IESO for RSVC Service effective for August 1, 2025-July 31, 2028. Under this agreement, for the period starting in 2027, OPG will only earn revenue tied to production losses resulting from provision of the RSVC service outside the standard capability range of the respective resources. OPG does not expect any provision of RSVC service outside of the standard capability range for the nuclear resources, and as such these revenues are set to zero for the IR term.

While it is expected that the DNNP facilities will also be able to supply RSVC service, likewise OPG does not expect any provision of RSVC service outside of the standard capability range, and as such these revenues are set to zero for the IR term.

OPG’s nuclear ancillary revenues have been subject to the Ancillary Revenues Variance Account – Nuclear Sub-Account. In view of the terms of the current RSVC agreement with the IESO that is expected to result in no ancillary revenues from the nuclear resources and given the relatively modest variance amounts historically settled through the sub-account, the Application proposes to discontinue entries into the Ancillary Revenues Variance Account – Nuclear Sub-Account as of the effective date of the payment amounts order in this proceeding. This is further discussed in Ex. H1-1-1, Section 5.2.

4.0 OPERATING COSTS OF NUCLEAR NON-ENERGY BUSINESSES

The operating costs of OPG's nuclear non-energy business are made up of direct costs (costs directly associated with producing or generating the product or service) and other support costs (primarily labour costs associated with sales, administration and other overheads). The direct costs of the nuclear non-energy business are shown in Ex. G2-1-1, Table 1 on an aggregated basis and are discussed below. Other support costs continue to be included in Nuclear Base OM&A costs (Ex. F2-2-1, Table 1a, Operations and Project Support).

4.1 Cobalt-60 (Excluding Darlington)

The direct costs for Cobalt-60 production at Pickering include installation, removal, processing, storage, and packaging of Cobalt-60. Direct costs also include a cost item for the long-term storage of the spent (but still radioactive) Cobalt-60, as the third-party agreement provides for the return of the spent Cobalt-60 to OPG for storage as nuclear waste. Under the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement between Bruce Power and OPG, OPG holds liability for the interim storage and future disposal of Bruce Power's spent Cobalt-60, and in return OPG receives payments from Bruce Power. The associated revenues are included in the Bruce Lease net revenues and are set out in Ex. G2-2-1, Table 2.

4.2 Tritium Sales

The direct costs for the tritium sales program are primarily Canadian Nuclear Laboratories' dispensing fees, packaging, and shipping costs. The product itself is a pure by-product of the detritiation process, and no production cost is attached to what is sold.

4.3 Heavy Water Sales

The direct costs for heavy water sales include labour for handling, testing, loading, unloading, and packaging, the cost of containers, and transportation costs. As discussed above, no such sales are anticipated over the IR term from the sales pool inventory.

4.4 Heavy Water Processing

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.

Table 1
Other Revenues - OPG Nuclear Facilities ($M)

Line No.	Revenue Source	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Non-energy Revenue:												
1	**Heavy Water Sales & Processing**	38.3	35.6	20.6	43.0	20.1	[redacted]						
2	**Isotope Sales (Pickering Cobalt 60 + Tritium)**	5.0	26.2	2.6	18.7	10.7							
3	**Total Non-energy Revenues** (line 1 + line 2)	43.3	61.8	23.2	61.7	30.8	49.6	42.9	16.4	43.5	24.4	23.8	34.5
4	**Non-energy Direct Costs**	7.1	6.4	11.0	12.4	11.4	10.5	10.3	10.1	10.8	10.6	10.3	10.9
5	**Non-energy Contribution Margin** (line 3 - line 4)	36.2	55.4	12.2	49.3	19.4	39.1	32.6	6.3	32.7	13.8	13.5	23.6
6	**Ancillary Services**	6.7	6.6	7.2	8.3	7.3	7.5	6.8	0.0	0.0	0.0	0.0	0.0
7	**Total** (line 5 + line 6)	42.9	62.0	19.4	57.6	26.7	46.6	39.4	6.3	32.7	13.8	13.5	23.6

COMPARISON OF NON-ENERGY REVENUES - NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of OPG's nuclear non-energy revenues net of related costs ("non-energy net revenues"). There are no non-energy revenues forecast to be derived from the DNNP facilities during the forecast period.

2.0 OVERVIEW

Exhibit G2-1-2, Tables 1a and 1b present year-over-year comparisons of OPG's nuclear non-energy net revenues.[1]

3.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, OPG NUCLEAR FACILITIES

2027 Plan versus 2026 Budget

Planned nuclear non-energy net revenues for 2027 are $6.3M, a decrease of $33.1M over such 2026 budgeted net revenues. This decrease is primarily due to lower revenues from heavy water processing due to an expected decrease in Tritium Removal Facility ("TRF") availability due to a planned outage to accommodate the TRF Major Component Replacement ("MCR") Program (Ex. D2-1-3, Section 3.1.3). Additionally, under the Reactive Support Voltage Control ("RSVC") agreement with the Independent Electricity System Operator, starting in 2027, OPG will only earn revenue from tied to production losses resulting from provision of the RSVC service outside the standard capability range of the respective resources. OPG does not expect any provision of RSVC outside of the standard capability range for the nuclear resources, and as such these revenues are set to zero for the IR term.

2028 Plan versus 2027 Plan

Planned nuclear non-energy net revenues for 2028 are $32.7M, an increase of $26.4M over such 2027 planned net revenues. This increase is primarily due to increased revenues from heavy water processing due to an expected increase in TRF availability to process heavy water in 2028 due to the completion of a planned TRF MCR outage, partially offset by decreased

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[1] Comparisons are before OEB settlement adjustments in EB-2020-0290 (2022-2026) and after OEB settlement adjustments in EB-2016-0152 (2020-2021).

Pickering Cobalt-60 revenue following the sale of such final Cobalt-60 harvest in 2027 as the Pickering units enter refurbishment.

2029 Plan versus 2028 Plan

Planned nuclear non-energy net revenues for 2029 are $13.8M, a decrease of $18.9M over such 2028 planned net revenues. This decrease is primarily due to lower revenues from heavy water processing due to a planned TRF MCR outage.

2030 Plan versus 2029 Plan

Planned nuclear non-energy net revenues for 2030 are $13.5M and are comparable to such 2029 planned net revenues.

2031 Plan versus 2030 Plan

Planned nuclear non-energy net revenues for 2031 are $23.6M, an increase of $10.1M over such 2030 planned net revenues. This increase is primarily due to increased revenues from heavy water processing due to higher TRF availability, due to the completion of the planned TRF MCR outage in 2030.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, OPG NUCLEAR FACILITIES

2026 Budget versus 2026 OEB-Approved

Budgeted nuclear non-energy net revenues for 2026 are $39.4M, a decrease of $24.4M over such 2026 OEB-approved net revenues. This decrease is primarily due to lower budgeted revenues from heavy water processing due to lower TRF availability and lower budgeted Cobalt-60 isotopes sales. The budgeted RSVC revenues are higher due to increased production losses resulting from higher utilization of the service.

2026 Budget versus 2025 Budget

Budgeted nuclear non-energy revenues for 2026 are $39.4M, a decrease of $7.2M over such 2025 budgeted net revenues. This is primarily due to a decrease in revenues from heavy water processing due to lower TRF availability.

2025 Budget versus 2025 OEB-Approved

Budgeted nuclear non-energy net revenues for 2025 are $46.6M, an increase of $24.8M over such 2025 OEB-approved net revenues. This increase is primarily due to higher budgeted revenues from heavy water processing as a result of updates to the TRF outage schedule, as well as an increase of expected Cobalt-60 sales due to scheduling of the cobalt harvest windows. The budgeted RSVC revenues are higher due to increased production losses resulting from higher utilization of the service.

2025 Budget versus 2024 Actual

Budgeted nuclear non-energy net revenues for 2025 are $46.6M, an increase of $19.9M over such 2024 actual net revenues. This increase is primarily due to lower revenues from heavy water processing in 2024, due to an unplanned TRF outage that limited heavy water processing services.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS, OPG NUCLEAR FACILITIES

2024 Actual versus 2024 OEB-Approved

Actual nuclear non-energy net revenues for 2024 were $26.7M, a decrease of $25.6M over such 2024 OEB-approved net revenues. This was primarily due to lower revenues from heavy water processing due to an unplanned TRF outage that limited heavy water processing availability in 2024. The RSVC revenues were higher due to increased production losses resulting from higher utilization of the service.

2024 Actual versus 2023 Actual

Actual nuclear non-energy net revenues for 2024 were $26.7M, a decrease of $30.9M over such 2023 actual net revenues. This decrease was primarily due to lower revenues from heavy water processing due to an unplanned TRF outage that limited heavy water processing availability in 2024, and lower Pickering Cobalt-60 sales due to timing of Cobalt-60 harvesting. The RSVC revenues were lower due to decreased production losses resulting from lower utilization of the service.

2023 Actual versus 2023 OEB-Approved

Actual nuclear non-energy net revenues for 2023 were $57.6M, an increase of $15.7M over such 2023 OEB-approved net revenues. This increase was primarily due to higher revenues from heavy water processing and higher tritiated heavy water sales. The RSVC revenues were higher due to increased production losses resulting from higher utilization of the service.

2023 Actual versus 2022 Actual

Actual nuclear non-energy net revenues for 2023 were $57.6M, an increase of $38.2M over such 2022 actual net revenues. This increase was primarily due to higher Pickering Cobalt-60 sales due to timing of Cobalt-60 harvesting and higher revenues from heavy water processing in 2023 compared to 2022 where production was affected by an extended TRF outage. The RSVC revenues were higher due to increased production losses resulting from higher utilization of the service.

2022 Actual versus 2022 OEB-Approved

Actual nuclear non-energy net revenues for 2022 were $19.4M, a decrease of $4.8M over such 2022 OEB-approved net revenues. This decrease was primarily due to lower revenues from heavy water processing due to an extended TRF outage, partially offset by higher tritiated heavy water sales. The RSVC revenues were higher due to increased production losses resulting from higher utilization of the service.

2022 Actual versus 2021 Actual

Actual nuclear non-energy net revenues for 2022 were $19.4M, a decrease of $42.5M compared to such 2021 actual net revenues. This decrease was primarily due to strong operational performance of the TRF in 2021 resulting in increased heavy water processing over the significantly lower heavy water processing in 2022 due to the extension of a TRF outage, as well as reduced Pickering Cobalt-60 sales due to scheduling of the cobalt harvest windows in 2022. The RSVC revenues were higher due to increased production losses resulting from higher utilization of the service.

2021 Actual versus 2021 OEB-Approved

Actual nuclear non-energy net revenues for 2021 were $62.0M, an increase of $37.3M compared to such 2021 OEB-approved net revenues. This increase was primarily due to higher Pickering Cobalt-60 sales due to shipments deferred from 2020, and higher revenues from heavy water processing. The RSVC revenues were higher due to compensating production losses at the prescribed regulated rate versus Hourly Ontario Energy Price in the previous contract.

2021 Actual versus 2020 Actual

Actual nuclear non-energy net revenues for 2021 were $62.0M, an increase of $19.1M compared to such 2020 actual net revenues. This increase was primarily due to increased Pickering Cobalt-60 sales resulting from shipments being deferred from 2020 to 2021.

2020 Actual versus 2020 OEB-Approved

Actual nuclear non-energy net revenues for 2020 were $42.9M, an increase of $19.1M compared to such 2020 OEB-approved net revenues. This increase was primarily due to increased heavy water sales and processing revenues and increased tritium sales, partially offset by lower Pickering Cobalt-60 sales due to the timing of Pickering planned outages and shipments being deferred to 2021. The RSVC revenues were higher due to compensating production losses at the prescribed regulated rate versus Hourly Ontario Energy Price in the previous contract.

Numbers may not add due to rounding.

Table 1a
Comparison of Other Revenues - OPG Nuclear Facilities ($M)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Non-energy Revenues:											
1	**Heavy Water Sales & Processing**[1]	16.7	21.6	38.3	(2.7)	16.8	18.8	35.6	(15.0)	24.0	(3.4)	20.6
2	**Isotope Sales (Pickering Cobalt 60 + Tritium)**	13.6	(8.6)	5.0	21.2	13.6	12.6	26.2	(23.6)	2.6	0.0	2.6
3	**Total Non-energy Revenues** (line 1 + line 2)	30.3	13.0	43.3	18.5	30.4	31.4	61.8	(38.6)	26.6	(3.4)	23.2
4	**Non-energy Direct Costs**	8.5	(1.4)	7.1	(0.7)	7.8	(1.4)	6.4	4.6	7.7	3.3	11.0
5	**Non-energy Contribution Margin** (line 3 - line 4)	21.8	14.4	36.2	19.2	22.7	32.7	55.4	(43.2)	18.9	(6.7)	12.2
6	**Ancillary Services**	1.9	4.8	6.7	(0.1)	2.0	4.6	6.6	0.7	5.3	1.9	7.2
7	**Total Before Adjustments** (line 5 + line 6)	23.8	19.1	42.9	19.1	24.6	37.3	62.0	(42.5)	24.2	(4.8)	19.4
8	**OEB/Settlement Adjustments**[2]		0.0		0.0		0.0		0.0	2.4	(2.4)	
9	**Total Including Adjustments** (line 8 + line 7)	23.8	19.1	42.9	19.1	24.6	37.3	62.0	(42.5)	26.6	(7.2)	19.4

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Non-energy Revenues:											
10	**Heavy Water Sales & Processing**[1]	20.6	22.4	26.5	16.5	43.0	(22.9)	45.9	(25.8)	20.1	[redacted]	[redacted]
11	**Isotope Sales (Pickering Cobalt 60 + Tritium)**	2.6	16.1	17.4	1.3	18.7	(8.0)	9.5	1.2	10.7	[redacted]	[redacted]
12	**Total Non-energy Revenues** (line 10 + line 11)	23.2	38.5	43.9	17.8	61.7	(30.9)	55.4	(24.6)	30.8	18.8	49.6
13	**Non-energy Direct Costs**	11.0	1.4	7.8	4.6	12.4	(1.0)	8.7	2.7	11.4	(0.9)	10.5
14	**Non-energy Contribution Margin** (line 12 - line 13)	12.2	37.1	36.1	13.2	49.3	(29.9)	46.7	(27.3)	19.4	19.7	39.1
15	**Ancillary Services**	7.2	1.1	5.8	2.5	8.3	(1.1)	5.6	1.7	7.3	0.2	7.5
16	**Total Before Adjustments** (line 14 + line 15)	19.4	38.2	41.9	15.7	57.6	(30.9)	52.3	(25.6)	26.7	19.9	46.6
17	**OEB/Settlement Adjustments**[2]		0.0	4.2	(4.2)		0.0	5.2	(5.2)		0.0	
18	**Total Including Adjustments** (line 16 + line 17)	19.4	38.2	46.1	11.6	57.6	(30.9)	57.5	(30.8)	26.7	19.9	46.6

Notes:
1. EB-2016-0152 heavy water sales reflect adjustments of $6.1M in 2017; $1.3M in 2018; $1.5M in 2019; $1.6M in 2020 and $1.7M in 2021 per partial settlement as described in EB-2016-0152 Decision Exhibit O page 11 of 17. The 2020-2024 Actuals are total amounts unadjusted for sharing.
2. 2022-2026 OEB-approved amounts are adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order EB-2020-0290, Schedule A, P. 27).

Numbers may not add due to rounding.

Table 1b

Comparison of Other Revenues - OPG Nuclear Facilities ($M)

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Non-energy Revenues:											
19	**Heavy Water Sales & Processing**[1]	19.2	[redacted]			45.5	[redacted]					
20	**Isotope Sales (Pickering Cobalt 60 + Tritium)**	2.6	[redacted]			21.3	[redacted]					
21	**Total Non-energy Revenues** (line 19 + line 20)	21.8	27.8	49.6	(6.7)	66.8	(23.9)	42.9	(26.5)	16.4	27.1	43.5
22	**Non-energy Direct Costs**	5.9	4.6	10.5	(0.2)	6.2	4.1	10.3	(0.2)	10.1	0.7	10.8
23	**Non-energy Contribution Margin** (line 21 - line 22)	15.9	23.2	39.1	(6.5)	60.6	(28.0)	32.6	(26.3)	6.3	26.4	32.7
24	**Ancillary Services**	5.9	1.6	7.5	(0.7)	3.2	3.6	6.8	(6.8)	0.0	0.0	0.0
25	**Total Before Adjustments** (line 23 + line 24)	21.8	24.8	46.6	(7.2)	63.8	(24.4)	39.4	(33.1)	6.3	26.4	32.7
26	**OEB/Settlement Adjustments**[2]	2.2	(2.2)		0.0	6.4	(6.4)					
27	**Total Including Adjustments** (line 25 + line 26)	24.0	22.6	46.6	(7.2)	70.2	(30.8)	39.4	(33.1)	6.3	26.4	32.7

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Non-energy Revenues:							
28	**Heavy Water Sales & Processing**	[redacted]						
29	**Isotope Sales (Pickering Cobalt 60 + Tritium)**	[redacted]						
30	**Total Non-energy Revenues** (line 28 + line 29)	43.5	(19.1)	24.4	(0.6)	23.8	10.7	34.5
31	**Non-energy Direct Costs**	10.8	(0.2)	10.6	(0.3)	10.3	0.6	10.9
32	**Non-energy Contribution Margin** (line 30 - line 31)	32.7	(18.9)	13.8	(0.3)	13.5	10.1	23.6
33	**Ancillary Services**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**Total** (line 32 + line 33)	32.7	(18.9)	13.8	(0.3)	13.5	10.1	23.6

Notes:

1 2025-2026 heavy water sales reflect adjustments of $0.2M in 2025; $0.2M in 2026; $0.2M in 2027; $0.2M in 2028; $0.2M in 2029; $0.2M in 2030 and $0.3M in 2031 per partial settlement as described in EB-2016-0152 Decision Exhibit O page 11 of 17.

2 2022-2026 OEB-approved amounts are adjusted to reflect a 10% increase in ancillary and other revenues forecast per the OEB approved settlement proposal (Decision and Order EB-2020-0290, Schedule A, P. 27).

BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce lease agreement and associated agreements (collectively, "Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations ("Bruce stations").

2.0 OVERVIEW

OPG leases the Bruce A (Units 1-4) and Bruce B (Units 5-8) Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Second Amended and Restated Bruce Lease Agreement ("Bruce Lease Agreement") as further amended, restated or replaced from time to time, sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have signed a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement ("Used Fuel Agreement"), the Amended and Restated Low and Intermediate Level Waste Agreement ("L&ILW Agreement"), and the Amended and Restated Bruce Site Services Agreement ("BSSA"), each as further amended, restated or replaced from time to time.

Bruce Power has options to renew the lease to December 31, 2064. OPG's IR term forecasts assume that Bruce Power will exercise its options to renew the lease.

The treatment of revenues and costs associated with the Bruce Lease Agreement and associated agreements, including the methodology for assigning and allocating such revenues and costs, is unchanged from previous OPG proceedings since EB-2007-0905.

For the IR term , the net amounts of Bruce Lease revenues and costs are forecast to be -$5.2M for 2027, $11.5M for 2028, -$18.1M for 2029, $7.3M for 2030, and -$17.1M for 2031 as shown in Ex. G2-2-1, Table 1. In accordance with O. Reg. 53/05 and the OEB's previous findings,[1] as applicable, these net amounts reduce or are applied towards the nuclear revenue requirements. Specifically, sections 6(2)9 and 6(2)10 of the O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts. Forecast revenues and costs applied towards the nuclear revenue requirements are trued-up to the actual revenues and costs through the Bruce Lease Net Revenues Variance Account.

Section 3.0 considers revenues from the Bruce Lease Agreement and associated agreements. Section 4.0 considers the costs incurred by OPG associated with the Bruce Lease. Discussion of Bruce Lease revenues and costs for the years 2020-2031 is provided in Sections 3.5 and 4.10, respectively.

3.0 BRUCE LEASE REVENUES

The forecast Bruce Lease revenues for the IR term are $235.3M for 2027, $257.0M for 2028, $230.2M for 2029, $264.5M for 2030, and $233.7M for 2031. Actual Bruce Lease revenues earned by OPG during the 2020-2024 period and the Bruce Lease revenues forecast to be earned during the 2025-2031 period are summarized in Ex. G2-2-1, Table 2. As in prior payment amounts proceedings, OPG derives revenues from the Bruce Lease Agreement and associated agreements as further described in Sections 3.1-3.4 below.

3.1 Bruce Lease Agreement Revenues

Revenues from the Bruce Lease consist of base rent and supplemental rent. Base rent is discussed in Section 3.1.1 and supplemental rent is discussed in Section 3.1.2.

[1] Decision and Order, EB-2016-0152, December 28, 2017, p. 91; Decision with Reason, EB-2013-0321, November 20, 2014, p.107; Decision with Reasons, EB-2010-0008, March 10, 2011, pp.100-101; Decision with Reasons, EB-2007-0905, November 3, 2008, pp. 105-112.

3.1.1 Base Rent Revenue

Pursuant to the Bruce Lease Agreement, Bruce Power paid OPG specified base rent payments for each year of the initial lease term up to the end of 2018. After the initial one-year renewal term in 2019, Bruce Power pays OPG base rent of $32M (2018$) for each subsequent two-year renewal period, upfront. These renewal payments are subject to Consumer Price Index ("CPI") escalation and are generally intended to cover the executory costs incurred by OPG in connection with the lease.[2]

As per the OEB's direction, OPG continues to determine lease revenue in accordance with GAAP for non-regulated businesses. As in prior OPG proceedings, this requires the application of a straight-line basis to determine lease revenue by dividing the total expected base rent revenues, excluding any payments intended to cover the lessor's executory costs, by the number of years in the expected lease term as determined for accounting purposes. Given that the full amount of base rent receivable since 2019 is considered to be for executory costs, the annual straight-line revenue amount remains fixed at $9.1M based on the base rent payments received prior to 2019 and the expected lease term for accounting purposes to the end of 2064.[3] The renewal base rent payments received beginning in 2019 are generally recognized on the same basis as the related executory costs. Accordingly, the forecast annual base rent revenue in this Application is a combination of the above fixed straight-line amount and one-half of the respective two-year renewal base rent payment. For the IR term, the resulting forecast base rent revenue increases gradually from $28.8M in 2027 to $30.4M in 2031.

Base rent revenue amounts are set out in Ex. G2-2-1, Table 2.

[2] An additional base rent (positive or negative) was introduced pursuant to an amendment to the Bruce Lease Agreement entered in 2024, as a mechanism to true-up recovery of certain OPG's costs related to the management of non-routine waste generated as part of Bruce Power's Major Component Replacement ("MCR") program. Any revenue related to this provision is included in low and intermediate level waste services revenues. Refer to Section 3.3 for further details.

[3] See EB-2020-0290, Ex. G2-02-Staff-318, Chart 1, columns [A] and [B].

3.1.2 Supplemental Rent Revenue

The monthly supplemental rent payable to OPG in addition to base rent represents the volumetric cost-based fee for managing Bruce Power's used fuel. OPG holds the liability for the interim storage and future disposal of the used fuel waste from the Bruce A and Bruce B reactors under the Used Fuel Agreement.

The costs used to determine the per fuel bundle fee (for all Bruce units) are based on the prevailing Ontario Nuclear Funds Agreement ("ONFA") Reference Plan estimates and are subject to annual CPI escalation. Accordingly, supplemental rent varies each period with the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays. Supplemental rent payments are also subject to a retrospective true-up adjustment to address any over or under-recovery of cost estimates, based on the most recent approved ONFA Reference Plan, for the used fuel discharged from January 1, 2016 onwards. The adjustment is payable or refundable over the remaining expected life of the longest running Bruce unit, less five years, and is reset following each approved ONFA Reference Plan.

Aside from the retrospective true-up adjustment, supplemental rent revenue is recognized on a cash basis for financial accounting purposes, as it is not a fixed amount. Each retrospective true-up adjustment is recognized as an increase or decrease to revenue, in full, in the period it is determined based on an approved ONFA Reference Plan. The forecast annual supplemental rent revenue is set out in Ex. G2-2-1 Table 2, ranging from \$169.9M to \$218.1M over the IR term. The year-over-year variability in the revenue is discussed further in Section 3.5.

3.2 Spent Cobalt-60 Revenues under the Used Fuel Agreement

Under the Used Fuel Agreement, OPG holds the liability for the interim storage and future disposal of Bruce Power's spent Cobalt-60 and, in return, receives payments from Bruce Power. As set out in Ex. G2-2-1, Table 2, the revenue from Bruce Power's Cobalt-60 storage and disposal services ranges from \$0.7M to \$0.8M per year during the IR term. Revenues for Cobalt-60 storage and disposal services are recorded as the services are provided.

3.3 Low and Intermediate Level Waste Agreements Revenues

Under the L&ILW Agreement, OPG manages the routine L&ILW received from Bruce Power.[4] In return for these services, Bruce Power pays OPG a volumetric, cost-based fee. The current agreement requires OPG to maintain the capacity to accept all of the L&ILW generated on the leased premises by or on behalf of Bruce Power. Similar to the used fuel fees (i.e., supplemental rent), the costs used to determine the volumetric fee rates are based on the prevailing ONFA Reference Plan estimates and are subject to annual CPI escalation. L&ILW fees are also subject to a retrospective true-up adjustment to address any over or under-recovery of cost estimates, based on the most recent approved ONFA Reference Plan, for the wastes received from January 1, 2016 onwards. The adjustment is payable or refundable over the remaining expected life of the longest running Bruce unit, less five years, and is reset following each approved ONFA Reference Plan.

Since 2020, OPG and Bruce Power have entered into three supplemental agreements to the L&ILW Agreement related to non-routine waste generated as part of Bruce Power's Major Component Replacement program ("MCR Supplemental Waste Agreements"). These agreements require Bruce Power to pay upfront fees determined on the basis of OPG's estimated costs of managing such L&ILW (e.g., steam generators and reactor pressure tubes) received from Bruce Power as a result of the MCRs for Bruce Units 6, 3 and 4, respectively. OPG expects to enter into a similar agreement for the MCR for Bruce Unit 5 by 2026. The corresponding revenues are reflected as L&ILW services revenues in 2020 and 2021 for Unit 6, 2024 and 2025 for Unit 3, 2025 and 2026 for Unit 4, and 2027 and 2028 for Unit 5.

In 2024, the parties amended the Bruce Lease Agreement and L&ILW Agreement to implement a true-up mechanism for certain cost estimates underpinning the fees payable by Bruce Power under the MCR Supplemental Waste Agreements. Under this mechanism, eligible costs are updated as additional base rent (positive or negative), based on the most recent approved ONFA Reference Plan, with any differences amortized over the remaining expected life of the longest running Bruce unit, less five years. The mechanism is intended to address the

[4] The L&ILW Agreement does not include non-routine waste generated as part of Bruce Power's Major Component Replacement program.

uncertainty and risk inherent in estimating future costs of managing the waste.

Revenues under the L&ILW Agreement and the MCR Supplemental Waste Agreements are recorded as the services are provided. Each retrospective true-up adjustment for routine or MCR waste fees, as applicable, is recognized as an increase or decrease to revenue, in full, in the period it is determined based on an approved ONFA Reference Plan. The forecast L&ILW services revenues are forecast to range from $14.6M to $35.3M over the IR term, as shown in Ex. G2-2-1, Table 2. The year-over-year variability in the revenue is discussed further in Section 3.5.

3.4 Bruce Site Services Agreement Revenues

The BSSA provides for various support and maintenance services that are provided by OPG to Bruce Power, and Bruce Power to OPG, on a cost recovery basis. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. OPG's site services revenues are set out in Ex. G2-2-1, Table 2 and are forecasted to range from $0.5M to $0.6M per year during the IR term.

Together, revenues under the L&ILW Agreement, the MCR Supplemental Waste Agreements and the BSSA, as well as spent Cobalt-60 revenues, comprise the services component of OPG's revenues from Bruce Power.

3.5 Comparison of Revenues

A comparison of revenues from the Bruce Lease for the 2020-2031 period is provided in Ex. G2-2-1, Tables 3a and 3b. Total annual revenues over the period range from $169.6M to $269.3M.

The fluctuations in services revenue over 2020-2031, from a low of $3.6M in 2022 to a high of $51.6M in 2024, primarily reflects variability in routine L&ILW volumes being received from Bruce Power, a decrease in revenue recognized in 2022 for the retrospective true-up adjustment of the routine waste fees under the L&ILW Agreement based on the 2022 ONFA Reference Plan cost estimates, and revenues under the MCR Supplemental Waste

Agreements in certain years. As in previous proceedings, OPG projects revenues under the L&ILW Agreement based on information received from Bruce Power regarding forecasted routine L&ILW volumes, while the actual waste volumes received are affected by the operations and refurbishment of the Bruce units. As noted in Section 3.3, the services revenue over the period includes revenue under the MCR Supplemental Waste Agreements in 2021 and each of 2024-2028.

Actual services revenue was above the OEB-approved amount in 2021 mainly due to revenues received under the MCR Supplemental Waste Agreement for Bruce Unit 6. The 2022 actual amounts were below the OEB-approved amount mainly due to a decrease in revenue recognized for the retrospective true-up adjustment of the routine waste fees under the L&ILW Agreement based on the 2022 ONFA Reference Plan cost estimates. In 2023, actual amounts were below the OEB-approved amount mainly due to lower than forecasted volumes of routine L&ILW waste received. In 2024, actual amounts were above the OEB-approved amount mainly due to revenues received under the MCR Supplemental Waste Agreement for Bruce Unit 3. Forecasted services revenue is above the OEB-approved amounts in 2025 and 2026 mainly due to revenues forecasted under the MCR Supplemental Waste Agreements for Bruce Unit 3 (in 2025) and Unit 4 (in 2025 and 2026).

Actual base rent revenue increased from $25.4M in 2020 to $28.0M in 2024 and is expected to continue to modestly increase to $30.4M in 2031, as forecast executory costs escalate at a CPI rate annually. There were no significant variances to OEB-approved amounts.

The fluctuations in supplemental rent revenue over 2020-2031, from a low of $139.7M in 2022 to a high of $218.1M in 2030, primarily reflect variability in the number of fuel bundles being discharged from the Bruce reactors. Such variability, together with differences in per fuel bundle fees, is also the primary reason for the supplemental rent revenue variance against the OEB-approved amounts in 2024-2026. As in previous proceedings, OPG projects supplemental rent revenues based on information received from Bruce Power regarding the forecasted number of used fuel bundles, while the actual number of fuel bundles discharged is affected by the operations and refurbishment of the Bruce units.

The discharged fuel bundles include those arising during the defueling of the Bruce units as they are taken offline for refurbishment as part of Bruce Power's MCR program. During the historical years, defuelling took place in 2020 (Unit 6) and 2023 (Unit 3). Defuelling estimates for the four remaining Bruce units to undergo refurbishment (Unit 4, Unit 5, Unit 7, and Unit 8) are reflected in the forecast period, based on information received from Bruce Power. These one-time increases in used fuel bundles are the main reason for the higher supplemental rent revenue amounts in the respective years. Otherwise, supplemental rent revenue is lower as Bruce units are offline for refurbishment.

4.0 BRUCE LEASE COSTS

For the IR term, the Bruce Lease costs forecast to be incurred by OPG are $240.5M for 2027, $245.5M for 2028, $248.3M for 2029, $257.1M for 2030, and $250.7M for 2031. Actual Bruce Lease costs incurred by OPG in the 2020-2024 period and forecast costs for the 2025-2031 period are summarized in Ex. G2-2-1, Table 1 and are further detailed in Ex. G2-2-1, Table 5. The categories of costs incurred by OPG with respect to the Bruce stations are consistent with those presented in the previous proceedings. Certain relatively minor costs incurred by OPG with respect to the Bruce stations, including services provided under the BSSA and for contract management oversight and administration, continue to be reflected in other aspects of OPG's nuclear revenue requirement and do not form part of the Bruce Lease net revenues.

4.1 Depreciation

Depreciation is calculated on the historical fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets primarily comprise the associated asset retirement costs ("ARC") shown in Ex. C2-1-1, Table 3. OPG applied the same methodology and depreciation policy as in previous proceedings, summarized in Ex. F4-1-1, to derive the depreciation expense for the 2020-2031 period. The average depreciation expense is forecast at $44.3M per year over the IR term, based on the closing December 31, 2024 Bruce station fixed asset balances. The continuity of Bruce fixed asset balances for the 2020-2031 period is presented in Ex. G2-2-1, Table 4.[5]

[5] There are no additions to the Bruce fixed assets, except for accounting changes to ARC, as any additions to the leased property made by Bruce Power are not recorded in OPG's accounting records.

4.2 Property Tax

Pursuant to the provisions of the Bruce Lease Agreement, OPG continues to pay property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F4-2-1, Section 6.0. The average property tax cost is forecast at $15.7M per year during the IR term.

4.3 Accretion

Accretion expense represents the growth in the present value-based asset retirement obligation ("ARO") due to the passage of time. The forecast accretion expense for 2025-2031 is derived by reference to the December 31, 2024 ARO balances attributed to the Bruce stations in OPG's 2024 year-end consolidated financial statements, using the same methodology as in previous proceedings. The recovery methodology for OPG's nuclear liabilities costs, including accretion expense, is discussed in further detail in Ex. C2-1-1. The continuity schedule for the Bruce stations' portion of the ARO is presented in Ex. C2-1-1, Table 3. The average accretion expense is forecast at $628.0M per year during the IR term.

4.4 Earnings on Nuclear Segregated Funds

OPG includes the portion of earnings from investments in the nuclear segregated funds attributed to the Bruce stations as a negative cost associated with these stations. These funds are maintained by OPG in accordance with the ONFA to provide funding for the long-term programs of the nuclear liabilities for the existing facilities. Discussed further in Ex. C2-1-1, the segregated fund earnings form part of the OEB-approved methodology for recovery of costs associated with OPG's nuclear liabilities for the Bruce facilities. The forecast segregated fund earnings for the 2025-2031 period are determined using the same methodology as in previous proceedings, by reference to the actual closing balance of the funds attributable to the Bruce stations as reflected in OPG's 2024 year-end consolidated financial statements. The continuity schedule for the portion of the segregated funds attributable to the Bruce stations is presented in Ex. C2-1-1, Table 3. The average earnings on the segregated funds are forecast at $537.6M per year during the IR term.

4.5 Used Fuel Storage and Disposal Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with the storage and disposal of incremental used nuclear fuel produced at the OPG-owned nuclear stations, including the stations on lease to Bruce Power. These costs are included as expenses related to the applicable nuclear facilities in the period incurred and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements. The average used fuel storage and disposal variable expenses are forecast at $69.9M per year during the IR term.

4.6 Waste Management Variable Expenses, Facilities Removal and Other Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with managing incremental L&ILW produced at the OPG-owned nuclear facilities, including the stations on lease to Bruce Power. In addition to routine waste received from Bruce Power, this includes incremental nuclear liabilities' costs incurred for any non-routine waste received under an MCR Supplemental Waste Agreement. Waste management variable costs are included as expenses related to the applicable nuclear facilities in the period incurred and are presented as part of OM&A expenses in OPG's consolidated financial statements. Any facilities removal costs or costs not otherwise categorized in this evidence that may be incurred by OPG to meet its obligations under the Bruce Lease are also included in this category of expenses. The average waste management variable expenses, facilities removal and other costs are forecast at $12.1M per year during the IR term per Ex. C2-1-1 Table 3, of which all costs relate to waste management variable expenses.

4.7 Interest

Interest related to the Bruce assets represents an allocation of the actual/forecast corporate-wide accounting interest expense after attributing interest related to specific projects and other investments to appropriate OPG businesses. As in EB-2020-0290, the allocation is based on a forecast of the proportion of the average net book value of the fixed assets leased to Bruce Power relative to the total average net book value of OPG's in-service fixed assets (including intangible assets and excluding in-service assets with specific attributed debt). The average interest expense over the IR term is forecast at $17.5M per year as shown on Ex. G2-2-1, Table 5.

4.8 Current Income Taxes

Current income taxes for the Bruce assets are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. These are the applicable pieces of legislation that together form the basis for OPG's overall payments in lieu of corporate income taxes. The amount of taxes is determined by applying the enacted statutory tax rate to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce assets' stand-alone accounting earnings before tax determined in accordance with US GAAP, for items with different accounting and tax treatment. The adjustments for 2020-2031 are consistent with those presented in prior OPG applications, subject to the incorporation of the excessive interest and financing expenses limitation ("EIFEL") rules, which took effect under the *Income Tax Act* (Canada) for taxation years beginning on or after October 1, 2023. As further discussed in Ex. F4-2-1, Section 3.2.9, the EIFEL rules can restrict the tax-deductible amounts of net interest and financing expenses for affected enterprises. The overall average current income tax expense is a forecast credit of $20.2M per year during the IR term. In addition to the above calculation of corporate income taxes.

4.9 Deferred Income Taxes

Deferred income taxes generally represent the amount of tax that will be payable/recoverable in the future upon reversal of temporary differences between the tax basis and the accounting carrying value of items recorded in the current year.[6] The deferred income tax expense is determined in accordance with GAAP for unregulated entities. The actual (2020-2024) and forecast (2025-2031) deferred income taxes are calculated on a stand-alone basis using the actual/forecast Bruce Lease revenue and Bruce Lease costs, as shown in Ex. G2-2-1, Tables 7 and 8. These calculations are consistent with those presented in prior OPG applications. The average deferred income tax expense is forecast at $21.6M per year during the IR term.

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[6] EB-2013-0321, Ex. G2-2-1, Section 5.9.

4.10 Comparison of Bruce Costs

A comparison of Bruce Lease costs for 2020-2031 is set out in Ex. G2-2-1, Tables 6a and 6b.

4.10.1 <u>Depreciation</u>

After decreasing from $69.6M in 2020 to $52.4M in 2022 and then to $44.3M in 2024, depreciation expense is expected to be stable over the remaining period to 2031. The decrease in 2022 was due to the year-end 2021 decrease in the Bruce stations' ARC of $599.9M, reflecting the 2022 ONFA Reference Plan update. In 2024, the year-end 2023 decrease in the Bruce stations' ARC of $314.3M, related to the extension of the accounting end-of-life dates for Pickering Units 5-8. Actual/forecasted depreciation expense is lower than the OEB-approved amounts from 2022-2026 for the same reasons. The ARC adjustments are discussed in Ex. C2-1-1.

4.10.2 <u>Property Tax</u>

Property tax expense increases gradually over the 2020-2031 from $12.3M in 2020 to $16.3M in 2031. Actual and budget property tax expenses are largely in line with OEB-approved from 2021-2026. Increase in the forecast property tax over the IR term reflects inflationary increases.

4.10.3 <u>Accretion</u>

Accretion expense decreased by $8.7M in 2022 over 2021, primarily due to the year-end 2021 decrease in the Bruce stations' ARO of $599.9M reflecting the 2022 ONFA Reference Plan update. Accretion expense in 2024 was substantially unchanged from 2023, as the impact of the year-end 2023 decrease in the Bruce stations' ARO of $438.7M related to the extension of the accounting end-of-life dates for Pickering Units 5-8 was largely offset by normal present value growth of the liability due to the passage of time. For the remainder of the period to 2031, the gradual increase in accretion expense is primarily a result of normal present value growth of the liability due to the passage of time. By 2031, forecast accretion expense is $668.1M. Adjustments to ARO are discussed in Ex. C2-1-1.

Actual 2020 and 2021 accretion expenses were higher than the OEB-approved amounts, primarily due to the impact of the year-end 2017 ARO adjustment related to changes in the accounting end-of-life dates for Pickering and lower expenditures against the ARO. Actual 2022 and 2023 accretion expenses were lower than the OEB-approved amount, mainly due to the year-end 2021 decrease in the Bruce stations' ARO. Actual and forecast accretion expense for 2024 to 2026 is lower than the OEB-approved amounts, mainly due to the combination of the year-end 2021 and year-end 2023 decreases to the Bruce stations' ARO.

4.10.4 Earnings on Nuclear Segregated Funds

The variability in the nuclear segregated funds earnings over the historical years primarily reflects a combination of the growth rate per the prevailing approved ONFA Reference Plan of 5.15% per annum, the impact of the contribution amounts pursuant to the prevailing ONFA contribution schedule, disbursements, and an adjustment to the accounting value of the funds recorded in 2022 to reflect the change in the funding liabilities as a result of the 2022 ONFA Reference Plan. As discussed further in Ex. C2-1-1, when both the Decommissioning Segregated Fund and the Used Fuel Fund are in a surplus position, as was the case during the historical period, fund asset values recognized for accounting purposes are limited by the funding liabilities and fund earnings are recorded at the rate of growth of the funding liabilities per the prevailing ONFA Reference Plan.

For 2025-2031, nuclear segregated fund earnings are forecast at a rate of 5.15% per annum consistent with the 2022 ONFA Reference Plan, which, together with the contribution amounts pursuant to the 2022 ONFA Contribution Schedule and projected disbursements, results in gradual increases in the earnings averaging approximately $17.0M per year over the period. By 2031, nuclear segregated fund earnings are forecast to reach $578.7M.

Actual 2020 nuclear segregated fund earnings were higher than the OEB-approved amount, primarily due to lower fund disbursements and a higher portion of the earnings attributable to the Bruce facilities. Actual 2022 nuclear segregated fund earnings were higher than the OEB-approved amount, primarily due to an adjustment to the accounting value of the funds to reflect the change in the funding liabilities as a result of the 2022 ONFA Reference Plan. Forecasted 2025 and 2026 nuclear segregated fund earnings are lower than the OEB-approved amount, primarily due to higher cumulative contribution amounts pursuant to the prevailing ONFA contribution schedule and higher cumulative actual and forecast disbursements. There are no significant variances relative to the OEB-approved amounts for the remaining historical and bridge years.

4.10.5 Used Fuel Storage and Disposal Costs

The variability in the used fuel storage and disposal variable expenses over the historical and bridge years and the IR term, from a low of $57.2M in 2026 to a high of $96.7M in 2023, primarily reflects a combination of the variability in the number of fuel bundles loaded into the Bruce reactors and changes in the per fuel bundle cost rates following each ARO adjustment recorded during the period. The number of actual and forecasted fuel bundles is based on information received from Bruce Power and, beginning in 2020, includes the effects of Bruce Power's ongoing MCR program, both from lower utilization of bundles due to the MCR outages and from higher utilization reflecting initial fuel loads into the refurbished reactors.[7]

The higher expenses in 2021 also reflected the impact of the year-end 2020 ARO adjustment related to changes in the accounting end-of-life dates for Pickering Units 1 and 4, which resulted in an increase in per fuel bundle cost rates due to a lower discount rate of 2.01% compared to the discount rate of 2.94% in effect prior to 2021.[8] The lower expenses in 2024 reflected the impact of the year-end 2023 ARO adjustment related to the extension of the accounting end-of-life dates for Pickering Units 5-8, which resulted in a decrease in per fuel bundle costs rates due to a higher discount rate of 3.93%.

Differences in used fuel variable expenses relative to OEB-approved amounts in the historical period are primarily a result of higher per bundle costs rates in 2021, 2022, and 2023, as discussed above. In 2025 and 2026, forecast used fuel variable expenses are lower than the OEB-approved amounts, primarily as a result of differences in the number of fuel bundles projected to be loaded into the Bruce reactors.

[7] Used fuel variable expenses are recognized at the time fuel is loaded into a reactor and becomes irradiated.
[8] EB-2020-0290, Ex. C2-1-1, Sections 4.1.2.

4.10.6 Waste Management Variable Expenses, Facilities Removal and Other Costs

The higher waste management variable expenses, facilities removal costs and other costs of $19.6M in 2021 reflected incremental costs related to the receipt of waste under the MCR Supplemental Waste Agreement for Bruce Unit 6, as well as a one-time cost incurred as part of a settlement reached with British Energy Limited and British Energy International Holdings Limited (together, “British Energy”), as an initial owner of Bruce Power, regarding their claim of contribution and indemnity from OPG for amounts British Energy was found liable for in an arbitration commenced against it by purchasers of British Energy’s interest in Bruce Power. The action and arbitration pertained to corrosion of a steam generator unit, discovered after OPG leased the Bruce stations to Bruce Power. The higher actual/forecast expenses averaging $18.2M over 2024-2028 reflect incremental costs related to the actual or anticipated receipt of waste under the MCR Supplemental Waste Agreements for Bruce Unit 3, Unit 4, and Unit 5.

In addition to the above factors, differences in waste management variable expenses, facilities removal and other costs relative to OEB-approved amounts in the historical and bridge periods reflect higher volumetric L&ILW cost rates based on the 2022 ONFA Reference Plan update beginning in 2022. Over the 2020-2031 period, expenses also reflect variability in routine waste volumes received from, or projected to be received based on information provided by, Bruce Power.

4.10.7 Interest

The interest expense associated with the Bruce assets decreased over the historical period, from $23.1M in 2020 to $5.6M in 2024, primarily due to a lower allocation factor for the Bruce assets, reflecting increases in-service assets for OPG’s prescribed facilities and decreases in the Bruce fixed assets owing to the year-end 2021 and 2023 ARO and ARC adjustments. Beginning in 2027, the interest expense associated with the Bruce assets is forecasted to increase, peaking at $25.3M in 2030 before declining to $18.6M in 2031. This reflects an increase in OPG’s corporate debt levels, partly offset by a declining allocation factor for the Bruce assets due to increases in in-service assets for OPG’s prescribed facilities, including upon return to service of Pickering Unit 5 from refurbishment in 2031.

The actual/forecasted interest expense associated with the Bruce assets is lower than the OEB-approved amounts for 2020-2026, mainly due to a lower allocation factor for the Bruce assets. For 2020 and 2021, this was mainly due to the use of a historical allocation factor to determine the EB-2016-0152 forecast amounts, which did not reflect the decrease in the Bruce fixed assets resulting from the subsequent year-end 2016 ARO and ARC adjustment reflecting the 2017 ONFA Reference Plan. For 2022-2024, the historical allocation factor used to determine the EB-2020-0290 forecast amounts similarly did not reflect the subsequent decreases in the Bruce fixed assets resulting from the year-end 2021 and year-end 2023 ARO and ARC adjustments.

4.10.8 Current Income Taxes

Actual current income tax expense in 2020, 2021, 2022, 2023 and 2024 was $33.1M, $45.0M, $69.8M, $78.0M, and $69.9M, respectively. Forecast amounts peak in 2025 at $82.5M before gradually declining to $37.3M, $25.5M, $24.3M, $10.2M, $21.2M, and $19.8M in 2026, 2027, 2028, 2029, 2030, and 2031, respectively. The higher current income taxes in years 2022-2024 were mainly due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule, compared to the previous approved contribution schedule in effect through 2021. The forecast peak income tax expense in 2025 is due primarily to higher segregated fund disbursements in that year. The declining trend through the IR term reflects lower forecast earnings before tax.

Actual income taxes for 2020 were lower than OEB-approved amounts mainly due to lower receipts from the nuclear segregated funds and lower Other deductible items. Actual income taxes in 2023 and 2024 and forecast income taxes in 2026 are higher than OEB-approved amounts mainly due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule. Forecast income taxes in 2025 are higher than OEB-approved amount due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule and higher earnings before tax.

4.10.9 Deferred Income Taxes

Actual deferred income taxes were -$37.0M, -$67.9M, -$81.5M, -$86.6M and -$55.8M in 2020, 2021, 2022, 2023 and 2024, respectively. Forecast deferred income taxes gradually increase and then level off through the IR term, at -$70.6M, -$28.4M, -$27.2M, -$20.5M, -$16.3M, -$18.7M and -$25.5M in 2025, 2026, 2027, 2028, 2029, 2030, and 2031, respectively. The lower deferred income tax expense in 2021 was due to temporary differences arising from higher receipts from the nuclear segregated funds and higher used fuel and waste management variable expenses. The further decline in deferred income tax expense in 2022 was primarily due to lower contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The increase in deferred income tax expense in 2024 was due to higher expenditures on decommissioning, used fuel and nuclear waste management activities. This is followed by a decrease in forecast deferred income tax expense in 2025 due to higher receipts from the nuclear segregated funds, and an increase in 2026 due to higher contributions to the nuclear segregated funds. The forecast deferred income tax expense varies over the IR term, reflecting smaller year-over-year variances across a number of sources of temporary differences.

The lower receipts from the nuclear segregated funds were the primary driver of the higher deferred income tax expense in 2020 compared to the OEB-approved amount. The lower deferred income tax expense in 2021 compared to the OEB-approved amount was due to lower expenditures on decommissioning, and higher used fuel and waste management variable expenses, partially offset by lower receipts from the nuclear segregated funds. The lower deferred income tax expense than the OEB-approved amount in 2023 (actual) and 2025 (forecast) is due to higher contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The higher deferred income tax expense in 2024 compared to the OEB-approved amount was due to lower depreciation and accretion expenses and higher expenditures on decommissioning, used fuel and nuclear waste management, partially offset by higher contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The higher deferred income tax expense forecast in 2026 compared to the OEB-approved amount is due to higher receipts from the nuclear segregated funds, partially offset by lower depreciation and accretion expenses.

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Bruce Lease Net Revenues:												
1	**Bruce Lease Revenues**	218.2	202.7	169.6	219.6	261.1	269.3	255.2	235.3	257.0	230.2	264.5	233.7
2	**Bruce Costs**	230.1	271.4	204.7	245.4	218.6	233.6	228.8	240.5	245.5	248.3	257.1	250.7
3	**Bruce Lease Net Revenues** (line 1 - line 2)	(11.9)	(68.7)	(35.1)	(25.8)	42.5	35.8	26.5	(5.2)	11.5	(18.1)	7.3	(17.1)

Numbers may not add due to rounding.

Table 2
Bruce Lease Revenues ($M)

Line No.	Revenue Source	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Site Services (OPG to Bruce Power)**		0.7	0.7	0.6	0.5	1.1	0.5	0.5	0.5	0.6	0.6	0.6	0.6
2	**Low & Intermediate Level Waste Services**		21.2	29.9	2.4	14.6	50.0	46.0	29.9	35.3	25.0	24.7	14.6	23.8
3	**Cobalt-60**		0.8	0.4	0.6	0.5	0.5	0.7	0.7	0.7	0.7	0.8	0.8	0.8
4	**Total Services Revenue**		22.7	30.9	3.6	15.6	51.6	47.2	31.1	36.6	26.4	26.0	16.0	25.2
5	**Fixed (Base) Rent**		25.4	25.4	26.3	26.3	28.0	28.0	28.8	28.8	29.6	29.6	30.4	30.4
6	**Supplemental Rent**		170.2	146.5	139.7	177.7	181.5	194.1	195.3	169.9	201.0	174.5	218.1	178.0
7	**Total Rent Revenue**		195.6	171.8	166.0	204.0	209.5	222.1	224.1	198.7	230.6	204.1	248.5	208.4
8	**Total Revenue** (line 4 + line 7)		218.2	202.7	169.6	219.6	261.1	269.3	255.2	235.3	257.0	230.2	264.5	233.7

Table 3a
Comparison of Bruce Lease Revenues ($M)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 1		Note 3		Note 1		Note 3		Note 2		Note 3
1	**Site Services (OPG to Bruce Power)**	0.7	0.0	0.7	(0.0)	0.7	0.0	0.7	(0.0)	0.5	0.1	0.6
2	**Low & Intermediate Level Waste Services**	18.6	2.6	21.2	8.7	21.6	8.3	29.9	(27.5)	18.1	(15.7)	2.4
3	**Cobalt-60**	0.5	0.2	0.8	(0.4)	0.5	(0.2)	0.4	0.2	0.6	(0.1)	0.6
4	**Total Services Revenue**	19.8	2.9	22.7	8.2	22.8	8.1	30.9	(27.3)	19.2	(15.6)	3.6
5	**Fixed (Base) Rent**	25.4	(0.0)	25.4	(0.0)	25.7	(0.4)	25.4	0.9	26.1	0.2	26.3
6	**Supplemental Rent**	174.5	(4.3)	170.2	(23.7)	140.1	6.3	146.5	(6.8)	140.4	(0.7)	139.7
7	**Total Rent Revenue**	200.0	(4.4)	195.6	(23.7)	165.9	5.9	171.8	(5.8)	166.5	(0.5)	166.0
8	**Total Revenue** (line 4 + line 7)	219.8	(1.5)	218.2	(15.5)	188.7	14.0	202.7	(33.2)	185.7	(16.1)	169.6

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 3		Note 2				Note 2				
9	**Site Services (OPG to Bruce Power)**	0.6	(0.1)	0.5	(0.0)	0.5	0.6	0.5	0.6	1.1	(0.6)	0.5
10	**Low & Intermediate Level Waste Services**	2.4	12.2	23.2	(8.6)	14.6	35.5	25.1	25.0	50.0	(4.1)	46.0
11	**Cobalt-60**	0.6	(0.0)	0.7	(0.1)	0.5	(0.1)	0.7	(0.2)	0.5	0.2	0.7
12	**Total Services Revenue**	3.6	12.0	24.4	(8.8)	15.6	36.0	26.3	25.3	51.6	(4.4)	47.2
13	**Fixed (Base) Rent**	26.3	0.0	26.4	(0.1)	26.3	1.7	26.8	1.2	28.0	(0.0)	28.0
14	**Supplemental Rent**	139.7	38.1	166.8	10.9	177.7	3.7	150.7	30.8	181.5	12.7	194.1
15	**Total Rent Revenue**	166.0	38.1	193.3	10.8	204.0	5.4	177.5	32.0	209.5	12.6	222.1
16	**Total Revenue** (line 12 + line 15)	169.6	50.1	217.6	2.0	219.6	41.5	203.7	57.3	261.1	8.2	269.3

Note:
1 2020 and 2021 OEB-approved amounts per EB-2016-0152, Ex. J21.2, Attachment 1, Table 1.
2 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 2.
3 2020 to 2022 actuals as shown in EB-2023-0336, Ex. H1-1-1, Table 11a.

Table 3b
Comparison of Bruce Lease Revenues ($M)

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 1				Note 1						
17	**Site Services (OPG to Bruce Power)**	0.5	0.0	0.5	0.0	0.5	0.0	0.5	(0.0)	0.5	0.1	0.6
18	**Low & Intermediate Level Waste Services**	20.3	25.7	46.0	(16.1)	24.3	5.6	29.9	5.5	35.3	(10.3)	25.0
19	**Cobalt-60**	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0	0.7
20	**Total Services Revenue**	21.5	25.7	47.2	(16.1)	25.5	5.6	31.1	5.5	36.6	(10.2)	26.4
21	**Fixed (Base) Rent**	27.1	0.9	28.0	0.8	27.5	1.3	28.8	0.0	28.8	0.8	29.6
22	**Supplemental Rent**	169.7	24.4	194.1	1.2	168.0	27.3	195.3	(25.4)	169.9	31.1	201.0
23	**Total Rent Revenue**	196.9	25.3	222.1	2.0	195.5	28.6	224.1	(25.4)	198.7	31.9	230.6
24	**Total Revenue** (line 20 + line 23)	218.4	50.9	269.3	(14.1)	221.0	34.2	255.2	(20.0)	235.3	21.7	257.0

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
25	**Site Services (OPG to Bruce Power)**	0.6	0.0	0.6	0.0	0.6	0.0	0.6
26	**Low & Intermediate Level Waste Services**	25.0	(0.4)	24.7	(10.1)	14.6	9.2	23.8
27	**Cobalt-60**	0.7	0.0	0.8	0.0	0.8	0.0	0.8
28	**Total Services Revenue**	26.4	(0.3)	26.0	(10.1)	16.0	9.2	25.2
29	**Fixed (Base) Rent**	29.6	(0.0)	29.6	0.8	30.4	0.0	30.4
30	**Supplemental Rent**	201.0	(26.5)	174.5	43.6	218.1	(40.0)	178.0
31	**Total Rent Revenue**	230.6	(26.5)	204.1	44.4	248.5	(40.0)	208.4
32	**Total Revenue** (line 28 + line 31)	257.0	(26.9)	230.2	34.3	264.5	(30.8)	233.7

Note:
1 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 2.

Table 4
Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2020 Actual [2]	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Opening Net Book Value**	2,822.3	2,765.7	2,096.0	2,043.6	1,676.8	1,632.5	1,588.2	1,543.9	1,499.6	1,455.4	1,411.1	1,366.8
2	**Add: Nuclear Liabilities Adjustment [3]**	13.0	(599.9)	0.0	(314.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	69.6	69.8	52.4	52.4	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
5	**Closing Net Book Value**	2,765.7	2,096.0	2,043.6	1,676.8	1,632.5	1,588.2	1,543.9	1,499.6	1,455.4	1,411.1	1,366.8	1,322.6

Notes:

1 Includes asset retirement costs presented in Ex. C2-1-1, Table 3.

2 2020 Actual Opening Net Book Value from EB-2020-0290, Ex. G2-2-1,Table 4, line 5, col (d).

3 Represents change in asset retirement costs effective December 31, 2020, December 31, 2021, and December 31, 2023 as shown at Ex. C2-1-1, Table 3: line 10, col (a); line 9, col. (b); and line 10, col. (d) respectively.

Table 5
Bruce Costs ($M)

Line No.	Cost Item	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Depreciation**		69.6	69.8	52.4	52.4	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
2	**Property Tax**		12.3	12.6	13.0	13.5	14.1	14.2	14.6	15.1	15.4	15.7	16.0	16.3
3	**Accretion**		504.1	522.3	513.6	534.1	535.7	550.5	567.3	587.8	607.6	626.9	649.5	668.1
4	**(Earnings) Losses on Segregated Funds**		(439.0)	(431.6)	(471.3)	(460.0)	(473.8)	(476.7)	(486.1)	(500.7)	(516.6)	(535.3)	(556.5)	(578.7)
5	**Used Fuel Storage and Disposal**		60.1	84.1	86.9	96.7	59.0	64.9	57.2	68.4	61.1	73.1	69.4	77.7
6	**Waste Management Expenses, Facilities Removal and Other Costs**		4.0	19.6	10.5	11.3	19.5	18.8	18.5	18.7	15.7	9.2	6.8	10.2
7	**Interest**		23.1	17.6	11.2	6.0	5.6	5.6	4.1	8.7	14.3	20.5	25.3	18.6
8	**Total Costs Before Income Tax**		234.1	294.3	216.4	254.0	204.5	221.6	219.9	242.3	241.7	254.3	254.7	256.4
9	**Income Tax - Current**		33.1	45.0	69.8	78.0	69.9	82.5	37.3	25.5	24.3	10.2	21.2	19.8
10	**Income Tax - Deferred**		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)	(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
11	**Total Income Tax**		(4.0)	(22.9)	(11.7)	(8.6)	14.2	11.9	8.8	(1.7)	3.8	(6.0)	2.4	(5.7)
12	**Total Costs** (line 8 + line 11)		230.1	271.4	204.7	245.4	218.6	233.6	228.8	240.5	245.5	248.3	257.1	250.7

Numbers may not add due to rounding.

Table 6a
Comparison of Bruce Costs ($M)

Line No.	Business Unit	Note	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 7		Note 9		Note 7		Note 9		Note 8		Note 9
1	**Depreciation**		68.4	1.2	69.6	0.2	68.4	1.4	69.8	(17.4)	69.6	(17.2)	52.4
2	**Property Tax**		14.0	(1.7)	12.3	0.2	15.1	(2.5)	12.6	0.4	12.6	0.4	13.0
3	**Accretion**	1	495.8	8.2	504.1	18.3	512.4	9.9	522.3	(8.7)	537.5	(23.9)	513.6
4	**(Earnings) Losses on Segregated Funds**	2	(426.2)	(12.8)	(439.0)	7.4	(436.0)	4.5	(431.6)	(39.7)	(452.6)	(18.7)	(471.3)
5	**Used Fuel Storage and Disposal**	3	64.2	(4.2)	60.1	24.0	52.2	31.9	84.1	2.9	57.9	29.0	86.9
6	**Waste Management Expenses, Facilities Removal Costs, and Other Costs**	4	3.4	0.6	4.0	15.6	4.6	14.9	19.6	(9.0)	3.2	7.4	10.5
7	**Interest**		26.8	(3.7)	23.1	(5.5)	25.8	(8.2)	17.6	(6.4)	18.3	(7.1)	11.2
8	**Total Costs Before Income Tax**		246.4	(12.3)	234.1	60.2	242.5	51.8	294.3	(78.0)	246.5	(30.1)	216.4
9	**Income Tax - Current**	5	47.0	(13.9)	33.1	12.0	41.7	3.4	45.0	24.8	75.9	(6.1)	69.8
10	**Income Tax - Deferred**	6	(53.6)	16.6	(37.0)	(30.9)	(55.1)	(12.8)	(67.9)	(13.6)	(91.1)	9.6	(81.5)
11	**Total Income Tax**		(6.7)	2.7	(4.0)	(18.9)	(13.4)	(9.5)	(22.9)	11.2	(15.2)	3.5	(11.7)
12	**Total Costs** (line 8 + line 11)		239.8	(9.6)	230.1	41.3	229.1	42.4	271.4	(66.8)	231.3	(26.6)	204.7

Line No.	Business Unit	Note	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 9		Note 8				Note 8				
13	**Depreciation**		52.4	(0.0)	69.6	(17.2)	52.4	(8.1)	69.6	(25.3)	44.3	(0.0)	44.3
14	**Property Tax**		13.0	0.5	12.6	0.9	13.5	0.6	12.6	1.5	14.1	0.1	14.2
15	**Accretion**	1	513.6	20.5	556.8	(22.7)	534.1	1.6	576.7	(41.0)	535.7	14.8	550.5
16	**(Earnings) Losses on Segregated Funds**	2	(471.3)	11.3	(462.0)	2.0	(460.0)	(13.8)	(475.1)	1.3	(473.8)	(3.0)	(476.7)
17	**Used Fuel Storage and Disposal**	3	86.9	9.7	69.5	27.2	96.7	(37.7)	63.3	(4.3)	59.0	5.9	64.9
18	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	10.5	0.8	4.2	7.1	11.3	8.2	4.5	15.1	19.5	(0.7)	18.8
19	**Interest**		11.2	(5.2)	18.6	(12.6)	6.0	(0.4)	16.3	(10.7)	5.6	0.0	5.6
20	**Total Costs Before Income Tax**		216.4	37.7	269.3	(15.2)	254.0	(49.6)	267.9	(63.5)	204.5	17.2	221.637
21	**Income Tax - Current**	5	69.8	8.2	48.9	29.1	78.0	(8.1)	49.8	20.1	69.9	12.6	82.5
22	**Income Tax - Deferred**	6	(81.5)	(5.1)	(61.8)	(24.8)	(86.6)	30.8	(65.9)	10.1	(55.8)	(14.8)	(70.6)
23	**Total Income Tax**		(11.7)	3.1	(12.9)	4.3	(8.6)	22.8	(16.0)	30.2	14.2	(2.2)	11.9
24	**Total Costs** (line 20 + line 23)		204.7	40.8	256.3	(10.9)	245.4	(26.8)	251.9	(33.3)	218.6	14.9	233.6

Notes:
1 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 4.
2 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 13.
3 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 2.
4 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 3.
5 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 20. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 20 and line 21.
6 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 28. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 28.
7 2020 and 2021 OEB-approved amounts per EB-2016-0152, Ex. J21.2, Attachment 1, Table 1.
8 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 5.
9 2020 to 2022 actuals as shown in EB-2023-0336, Ex. H1-1-1, Table 11a; amount in line 18, col. (a) reflects updated calculations of the dollar per cubic metre cost rates for low and intermediate level waste based on the 2022 ONFA Reference Plan.

Table 6b
Comparison of Bruce Costs ($M)

Line No.	Business Unit	Note	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 7				Note 7						
25	**Depreciation**		69.6	(25.2)	44.3	(0.0)	69.5	(25.2)	44.3	(0.0)	44.3	0.0	44.3
26	**Property Tax**		12.6	1.6	14.2	0.4	12.6	2.0	14.6	0.4	15.1	0.3	15.4
27	**Accretion**	1	599.6	(49.1)	550.5	16.8	623.7	(56.4)	567.3	20.5	587.8	19.8	607.6
28	**(Earnings) Losses on Segregated Funds**	2	(491.0)	14.2	(476.7)	(9.4)	(510.3)	24.2	(486.1)	(14.6)	(500.7)	(15.9)	(516.6)
29	**Used Fuel Storage and Disposal**	3	72.0	(7.1)	64.9	(7.7)	59.7	(2.5)	57.2	11.2	68.4	(7.3)	61.1
30	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	3.8	15.0	18.8	(0.3)	4.7	13.8	18.5	0.2	18.7	(3.0)	15.7
31	**Interest**		13.8	(8.2)	5.6	(1.5)	12.2	(8.1)	4.1	4.6	8.7	5.5	14.3
32	**Total Costs Before Income Tax**		280.3	(58.7)	221.6	(1.7)	272.1	(52.2)	219.9	22.3	242.3	(0.6)	241.7
33	**Income Tax - Current**	5	31.3	51.2	82.5	(45.3)	28.8	8.4	37.3	(11.8)	25.5	(1.2)	24.3
34	**Income Tax - Deferred**	6	(46.8)	(23.8)	(70.6)	42.2	(41.6)	13.2	(28.4)	1.2	(27.2)	6.7	(20.5)
35	**Total Income Tax**		(15.5)	27.4	11.9	(3.1)	(12.8)	21.6	8.8	(10.6)	(1.7)	5.6	3.8
36	**Total Costs** (line 32 + line 35)		264.9	(31.3)	233.6	(4.8)	259.3	(30.6)	228.8	11.8	240.5	5.0	245.5

Line No.	Business Unit	Note	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
37	**Depreciation**		44.3	(0.0)	44.3	0.0	44.3	(0.0)	44.3
38	**Property Tax**		15.4	0.3	15.7	0.3	16.0	0.3	16.3
39	**Accretion**	1	607.6	19.3	626.9	22.6	649.5	18.6	668.1
40	**(Earnings) Losses on Segregated Funds**	2	(516.6)	(18.7)	(535.3)	(21.2)	(556.5)	(22.2)	(578.7)
41	**Used Fuel Storage and Disposal**	3	61.1	12.0	73.1	(3.7)	69.4	8.3	77.7
42	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	15.7	(6.5)	9.2	(2.4)	6.8	3.4	10.2
43	**Interest**		14.3	6.3	20.5	4.7	25.3	(6.7)	18.6
44	**Total Costs Before Income Tax**		241.7	12.6	254.3	0.4	254.7	1.8	256.4
45	**Income Tax - Current**	5	24.3	(14.1)	10.2	11.0	21.2	(1.4)	19.8
46	**Income Tax - Deferred**	6	(20.5)	4.2	(16.3)	(2.5)	(18.7)	(6.7)	(25.5)
47	**Total Income Tax**		3.8	(9.9)	(6.0)	8.5	2.4	(8.1)	(5.7)
48	**Total Costs** (line 44 + line 47)		245.5	2.8	248.3	8.8	257.1	(6.4)	250.7

Notes:
1 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 4.
2 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 13.
3 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 2.
4 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 3.
5 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 20. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 20 and line 21.
6 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 28. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 28.
7 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 5.

Table 7
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2020, 2021, 2022, 2023, 2024 and 2025

Line No.	Particulars	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Taxable Income							
1	**Earnings (Loss) Before Tax**	1	(15.9)	(91.6)	(46.8)	(34.4)	56.6	47.7
	Additions for Tax Purposes - Temporary Differences:							
2	**Base Rent Accrual**		(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)
3	**Depreciation**		69.6	69.8	52.4	52.4	44.3	44.3
4	**Accretion**		504.1	522.3	513.6	534.1	535.7	550.5
5	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0	0.0
6	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		64.0	92.6	97.5	108.0	78.5	83.7
7	**Receipts from Nuclear Segregated Funds**		72.7	93.7	102.0	84.0	95.0	219.6
8	**Other**		(29.4)	10.9	2.4	6.4	9.7	5.6
9	**Total Additions - Temporary Differences** (lines 2 through 8)		671.9	780.2	758.8	775.9	754.1	894.6
	Deductions for Tax Purposes - Temporary Differences:							
10	**CCA**		12.9	10.9	10.9	10.1	8.2	8.2
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		174.4	168.6	150.5	159.5	249.1	243.6
12	**Contributions to Nuclear Segregated Funds**		(102.5)	(102.5)	(200.1)	(200.1)	(200.1)	(116.4)
13	**Earnings (Losses) on Nuclear Segregated Funds**		439.0	431.6	471.3	460.0	473.8	476.7
14	**Total Deductions - Temporary Differences** (lines 10 through 13)		523.8	508.5	432.6	429.5	531.1	612.1
15	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 14)		132.2	180.1	279.4	312.0	279.7	330.1
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over** (line 15 + line 16)		132.2	180.1	279.4	312.0	279.7	330.1
	Determination of Total Current Income Taxes							
18	**Taxable Income After Loss Carry-Over** (from line 17)		132.2	180.1	279.4	312.0	279.7	330.1
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current** (line 18 x line 19)		33.1	45.0	69.8	78.0	69.9	82.5
	Determination of Total Deferred Income Taxes							
22	**Total Net Temporary Differences** (line 9 - line 14)		148.1	271.7	326.1	346.4	223.1	282.5
23	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
24	**Deferred Income Taxes** (line 22 x -1 x line 23)		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)
25	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0	0.0
26	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
27	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over** (line 25 x line 26)		0.0	0.0	0.0	0.0	0.0	0.0
28	**Deferred Income Taxes - Total** (line 24 + line 27)		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)
	Income Tax Rate - Current							
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term							
32	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
33	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
34	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

Notes:
1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 8 and Total Costs Before Income Tax in Ex. G2-2-1 Table 5, Line 8 for each corresponding year.

Table 8
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2026, 2027, 2028, 2029, 2030 and 2031

Line No.	Particulars	Note	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Taxable Income							
1	**Earnings (Loss) Before Tax**	1	35.3	(7.0)	15.3	(24.2)	9.8	(22.8)
	Additions for Tax Purposes - Temporary Differences:							
2	**Base Rent Accrual**		(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)
3	**Depreciation**		44.3	44.3	44.3	44.3	44.3	44.3
4	**Accretion**		567.3	587.8	607.6	626.9	649.5	668.1
5	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0	0.0
6	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		75.7	87.1	76.8	82.3	76.2	87.9
7	**Receipts from Nuclear Segregated Funds**		170.5	196.0	187.0	118.4	129.9	122.0
8	**Other**		1.6	3.8	0.0	0.0	0.0	0.0
9	**Total Additions - Temporary Differences** (lines 2 through 8)		850.3	909.8	906.6	862.7	890.8	913.2
	Deductions for Tax Purposes - Temporary Differences:							
10	**CCA**		7.4	6.5	5.9	5.4	4.7	4.1
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		282.3	293.8	302.2	256.9	254.6	228.6
12	**Contributions to Nuclear Segregated Funds**		(39.2)	0.0	0.0	0.0	0.0	0.0
13	**Earnings (Losses) on Nuclear Segregated Funds**		486.1	500.7	516.6	535.3	556.5	578.7
14	**Total Deductions - Temporary Differences** (lines 10 through 13)		736.5	800.9	824.7	797.7	815.8	811.4
15	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 14)		149.0	101.9	97.3	40.9	84.7	79.0
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over** (line 15 + line 16)		149.0	101.9	97.3	40.9	84.7	79.0
	Determination of Current Income Taxes							
18	**Taxable Income After Loss Carry-Over** (from line 17)		149.0	101.9	97.3	40.9	84.7	79.0
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current** (line 18 x line 19)		37.3	25.5	24.3	10.2	21.2	19.8
	Determination of Total Deferred Income Taxes							
22	**Total Net Temporary Differences** (line 9 - line 14)		113.7	108.9	81.9	65.1	75.0	101.8
23	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
24	**Deferred Income Taxes** (line 22 x -1 x line 23)		(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
25	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0	0.0
26	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
27	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over** (line 25 x line 26)		0.0	0.0	0.0	0.0	0.0	0.0
28	**Deferred Income Taxes - Total** (line 24 + line 27)		(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
	Income Tax Rate - Current							
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term							
32	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
33	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
34	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 8 and Total Costs Before Income Tax in Ex. G2-2-1, Table 5, Line 8 for each corresponding year.

DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG and DNNP LP's existing deferral and variance accounts and presents the amounts recorded in OPG's accounts as of December 31, 2024 that are proposed for clearance in this Application. The accounts were established pursuant to Ontario Regulation 53/05 ("O. Reg. 53/05") and past OEB decisions and orders. This evidence also describes new deferral and variance accounts that the Application proposes to establish for OPG and DNNP LP.

To distinguish between existing or new accounts by the same name for OPG and DNNP LP, a corresponding notation of "(OPG)" or "(DNNP)" has been added to the account nomenclature throughout this Application, where applicable.

2.0 OVERVIEW

The Application proposes to clear the audited balances in all of OPG's deferral and variance accounts as at December 31, 2024, less amortization amounts previously approved by the OEB in EB-2023-0336 and EB-2020-0290 for the 2025-2026 period, with the exceptions noted below. The Application is not seeking clearance of the following balances in OPG's accounts: the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA"), the components of the Nuclear Development Variance Account ("NDVA") not related to the Darlington New Nuclear Program ("DNNP"), and the Pickering B Variance Account.[1] OPG proposes to defer the clearance of these balances to a future application for the reasons discussed later in this exhibit. The proposal to clear the remaining account balances is consistent with the OEB's expectation that "all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so."[2]

[1] The following deferral and variance accounts have a zero balance as at December 31, 2024: Gross Revenue Charge Variance Account, Hydroelectric Incentive Mechanism Variance Account, Earnings Sharing Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Impact for IFRS Deferral Account.

[2] Decision with Reasons, EB-2013-0321, November 20, 2014, p.125.

Adjusted for 2025-2026 amortization amounts approved in EB-2020-0290 and EB-2023-0336, the proposed year-end 2024 account balances for disposition in this Application are a net credit balance of $102.4M[3] for OPG's regulated hydroelectric facilities and a net debit balance of $878.8M[4] for OPG's nuclear facilities.[5] There are no account balances for DNNP LP as at December 31, 2024, as DNNP LP was not then in existence.[6]

Details regarding proposed account clearance and riders are presented in Ex. H1-2-1. The audited balances in each of the deferral and variance accounts are shown in Ex. H1-1-1, Table 1. The unqualified Independent Auditors' Report prepared by Ernst & Young LLP on the Schedule of Regulatory Balances as at December 31, 2024 is presented as Attachment 1. The Schedule of Regulatory Balances as at December 31, 2024 itself is presented as Attachment 2.

The Application proposes to continue all existing deferral and variance accounts, using the methodologies that have been used to record entries into the accounts to date as approved by the OEB, with certain exceptions as discussed in this exhibit. The Application proposes to terminate the Hydroelectric Incentive Mechanism Variance Account, the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account and the Incremental Cloud Computing Arrangement Implementation Costs Deferral Account. The Application also proposes to: (i) align the methodology of the CRVA as it applies to the regulated hydroelectric facilities with the proposed rate-setting framework for the 2027-2031 ("IR") term; (ii) expand the scope of the Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities, along with capturing the revenue requirement impact of any legislated or regulatory changes to the gross revenue charge ("GRC") construct; and (iii) extend the SR&ED ITC Variance Account (OPG) to include OPG's regulated hydroelectric facilities. These proposals, as well as proposals for a number of new deferral and variance accounts for OPG and DNNP LP, are discussed later in this exhibit.

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[3] Ex. H1-2-1, Table 1, col. (f) line 16.
[4] Ex. H1-2-1, Table 2, col. (f) line 30.
[5] A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.
[6] Refer to Ex. A1-4-4 for an overview of DNNP LP and its representation in this Application.

The following information is provided in this exhibit:

- Section 3.0 lists the existing and proposed new deferral and variance accounts for each of OPG and DNNP LP.
- Section 4.0 describes the proposed approach to determining the applicable reference amounts for additions to OPG and DNNP LP's deferral and variance accounts as of the effective date of the payment amounts order for this application.
- Section 5.0 describes OPG's existing deferral and variance accounts and details how additions to each of the accounts have been determined, and are proposed to be determined as of the effective date of the payment amounts order in this proceeding, or as otherwise applicable.
- Section 6.0 describes DNNP LP's existing deferral and variance accounts, which are established pursuant to O. Reg. 53/05, and outlines how additions are proposed to be determined as of the effective date of the payment amounts order in this proceeding, or as otherwise applicable.
- Section 7.0 sets out the details of new deferral and variance accounts proposed to be established for OPG as of the effective date of the payment amounts order in this proceeding.
- Section 8.0 sets out the details of new deferral and variance accounts proposed to be established for DNNP LP as of the effective date of the payment amounts order in this proceeding.
- Section 9.0 discusses the application of interest to the balances in the accounts.

3.0 LISTING OF EXISTING AND PROPOSED NEW ACCOUNTS

3.1 Existing Accounts for OPG

The authorized deferral and variance accounts for OPG are listed below. The Application proposes to continue all of the existing deferral and variance accounts, unless otherwise noted.

The following existing accounts are proposed to continue to record additions:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric Sub-Account
- Hydroelectric Surplus Baseload Generation Variance Account

- Income and Other Taxes Variance Account (OPG)
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account (OPG)
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG)
- Rate Smoothing Deferral Account
- SR&ED ITC Variance Account (OPG)
- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Primary and Contra Sub-Accounts, and Carrying Charges Sub-Account
- Pickering Closure Costs Deferral Account
- Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account
- Earnings Sharing Deferral Account
- Impact for IFRS Deferral Account (OPG)
- Pickering B Variance Account[7]
- Pickering B Refurbishment Project Variance Account, effective January 1, 2026[8]
- Darlington New Nuclear Project Variance Account, effective January 1, 2026[9].

The following existing accounts are proposed to continue to record only amortization and interest, as applicable:

- Ancillary Services Net Revenue Variance Account – Nuclear Sub-Account
- Pension & OPEB Cash Payment Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Fitness for Duty Deferral Account

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[7] Established pursuant to amendments to O. Reg. 53/05 made in December 2022 and July 2025.
[8] Established pursuant to amendment to O. Reg. 53/05 made in December 2025.
[9] Established pursuant to amendment to O. Reg. 53/05 made in December 2025.

- Clarington Corporate Campus Deferral Account
- Sale of Unprescribed Kipling Site Deferral Account.

The following existing accounts are proposed to be terminated:
- Hydroelectric Incentive Mechanism Variance Account
- Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account
- Incremental Cloud Computing Arrangement Implementation Costs Deferral Account.

3.2 Existing Accounts for DNNP LP

The authorized deferral and variance accounts for DNNP LP are listed below. The Application proposes to continue recording additions in all of the existing deferral and variance accounts.
- Darlington New Nuclear Project Variance Account re Development, expected to be effective January 1, 2026[10]
- Darlington New Nuclear Project Variance Account re Capital Cost Amounts, expected to be effective January 1, 2026[11]
- DNNP Generator Capital Structure Variance Account, expected to be effective January 1, 2026.[12]

3.3 Proposed New Accounts for OPG

New deferral and variance accounts proposed for OPG as of the effective date of the payment amounts order in this proceeding are listed below.
- Change of Laws Deferral Account (OPG)
- Global Hydroelectric Capital Variance Account
- Clean Electricity ITC Variance Account (OPG)
- Payment Amount Shaping Deferral Account

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[10] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.
[11] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.
[12] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.

- DNNP Nuclear Liability Deferral Account.

3.4 Proposed New Accounts for DNNP LP

New deferral and variance accounts proposed for DNNP LP as of the effective date of the payment amounts order in this proceeding are listed below.

- Income and Other Taxes Variance Account (DNNP)
- Pension and OPEB Cost Variance Account (DNNP)
- Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
- SR&ED ITC Variance Account (DNNP)
- Impact for IFRS Deferral Account (DNNP)
- Clean Electricity ITC Variance Account (DNNP)
- Impact of Change in Tax Status Variance Account (DNNP)
- Change of Laws Deferral Account (DNNP)

4.0 ACCOUNT ADDITIONS AS OF THE EFFECTIVE DATE OF THE PAYMENT AMOUNTS ORDER IN THIS PROCEEDING

4.1 OPG's Hydroelectric Deferral and Variance Account Additions

The Application proposes that the reference amounts used to determine additions to the following OPG hydroelectric deferral and variance accounts as of the effective date of the payment amounts order in this proceeding be the forecasts underpinning the approved regulated hydroelectric revenue requirement and payment amounts for 2027, where applicable:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric Sub-Account
- Pension & OPEB Cost Variance Account (OPG)
- Capacity Refurbishment Variance Account (non-capital portion)
- Gross Revenue Charge Variance Account
- SR&ED ITC Variance Account (OPG)
- Change of Laws Deferral Account (OPG) (non-capital portion)

As discussed in Ex. A1-3-2, Section 2.0, the Application proposes that the hydroelectric payment amounts be set in this proceeding to reflect, through the combination of the capital funding provided through the I-X formula and the C-factor, the respective annual revenue requirement impact of the forecast capital costs (including income tax expense) for OPG's regulated hydroelectric facilities (net of stretch factor adjustment). Consistent with this methodology, it is proposed that the reference amounts for the CRVA (capital portion), the Income and Other Taxes Variance Account, the proposed Change of Laws Deferral Account (capital portion), and the proposed Clean Electricity ITC Variance Account accounts reflect the corresponding annual amounts forecast for each respective year.

Based on the nature of the other hydroelectric deferral and variance accounts, their reference amounts are not based on the OEB-approved forecast amounts underpinning the payment amounts.

4.2 OPG and DNNP LP's Nuclear Deferral and Variance Account Additions

OPG proposes that the reference amounts used to determine additions to OPG and DNNP LP's applicable nuclear deferral and variance accounts as of the effective date of the payment amounts order in this proceeding be the annual forecasts underpinning the respective approved nuclear revenue requirements for each year, unless otherwise specified in the account descriptions.

5.0 OPG's ACCOUNT DESCRIPTIONS AND ENTRIES

This section provides a description and sets out the purpose of OPG's existing deferral and variance accounts, describes how additions to the accounts are determined, and outlines the reasons for the credits and debits recorded to the accounts that the Application seeks to clear. Unless otherwise specified, no changes have been made to the process by which entries are recorded to the accounts since they were last approved by the OEB, including in EB-2023-0336.

5.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and all subsequent OPG applications in recognition of the fact that water conditions are subject to a high degree of forecast risk due to factors that are beyond OPG's ability to manage or control, such as weather.

This account records the financial impact of differences, including changes in GRC costs, between the actual production amount for the regulated hydroelectric facilities and the reference production amount, arising from changes in actual water conditions. The account applies to the 27 prescribed hydroelectric stations that are listed in Ex. E1-1-1, Appendix 1.

For the Sir Adam Beck 1 and 2 and the R.H. Saunders generating stations, which became regulated by the OEB effective on April 1, 2008, OPG determines the hydroelectric production impact of changes in water conditions by entering the actual flow values into the same models used to calculate the production forecast for these facilities that underpins the payment amounts approved by the OEB, holding all other variables constant. Deviations from the forecast are determined as the difference between the calculated production resulting from entering actual flow for the month into the forecast model and the energy production forecast approved by the OEB. Until the effective date of the payment amounts order in this proceeding, deviations from the forecast for these facilities are calculated using the average of the corresponding monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

Until the effective date of the payment amounts order in this proceeding, for the 21 remaining regulated hydroelectric stations listed in Ex. E1-1-1, Attachment 1, deviations from the forecast for January 1-June 30 of each year are calculated using the corresponding monthly production forecasts for 2015 underpinning the EB-2013-0321 payment amounts. For July 1-December 31 of each year, the reference amounts are the average of the corresponding monthly production forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts. These stations became regulated by the OEB effective on July 1, 2014.

The revenue impact of the production deviations resulting from the above process is recorded in the account by multiplying the deviation by the approved hydroelectric payment amount in effect.[13]

As of the effective date of the payment amounts order in this proceeding, the Application proposes that the above methods used to calculate deviations in energy production due to actual water flows and associated financial impact continue to be used, for the same stations as identified above, substituting the 2014 and 2015 forecasts with the 2027 annual production forecasts described in Ex. E1-1-1.

Models are not used to derive energy production forecasts for the remaining 27 regulated hydroelectric facilities, listed in Ex. E1-1-1, Attachment 2. These stations account for less than 2% of total production from all regulated hydroelectric stations. Given the small size of these facilities, and consistent with prior OEB decisions, these facilities are excluded from the scope of the Hydroelectric Water Conditions Variance Account.

The account also records changes in GRC costs from those that underpin the payment amounts that were approved by the OEB, as a result of differences in energy production calculated as above. Amounts recorded in the account in respect of these costs are determined by multiplying the production deviation by the applicable GRC rate. The account also records any production related variances in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal, as well as any production related variances in the amounts payable to the Government of Quebec for water rentals, from those reflected in the payment amounts that were approved by the OEB. Additional details on the GRC, water rental and similar costs can be found in Ex. F1-4-1.

Due to favourable water supply conditions, the calculated actual hydroelectric production was higher than the reference forecast production by 1,756 GWh (in 2023) and 1,424 GWh (in 2024) for the Niagara and R.H. Saunders facilities. This was partially offset by lower calculated

[13] For the DeCew Falls generating stations, which became regulated by the OEB effective on April 1, 2008, account entries are limited to instances when actual Lake Erie levels reduce water diversion to the stations.

actual production for the remaining regulated hydroelectric facilities of 290 GWh (in 2023) and 206 GWh (in 2024). These variances resulted in a net credit addition of $41.3M to the account in 2023 and $35.1M in 2024. The derivation of the variances is shown in Ex. H1-1-1, Table 2.

5.2 Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts

The Ancillary Services Net Revenue Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and has been approved in all subsequent OPG applications. This account recognizes that ancillary services revenues are difficult to forecast accurately, with variability in actual ancillary revenues reflecting changing demand and system operating requirements.

The account is divided into the Ancillary Services Net Revenue Variance Account – Hydroelectric and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts. Ancillary services for regulated hydroelectric operations include black start capability, operating reserve, regulation service, and reactive support/voltage control service, as discussed in Ex. G1-1-1. Ancillary services for the nuclear operations include reactive support/voltage control service, as discussed in Ex. G2-1-1.

For the Hydroelectric Sub-Account, until the effective date of the payment amounts order in this proceeding, the variance recorded is calculated as between actual regulated hydroelectric ancillary services net revenue and the average of the monthly forecast amounts for 2014 and 2015 underpinning the regulated hydroelectric revenue requirement approved by the OEB in EB-2013-0321. As of the effective date of the payment amounts order in this proceeding, the Application proposes to continue this method of determining additions to the Hydroelectric Sub-Account, substituting the 2014 and 2015 forecasts with the annual forecast reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB. Forecast regulated hydroelectric ancillary services revenue for 2027 is provided at Ex. G1-1-1, Table 1, line 7.

As discussed in Ex. G2-1-1, OPG does not expect to receive any nuclear ancillary services revenue, beginning in 2027, under the new reactive support and voltage control agreement with the IESO. As a result, and given the relatively modest variance amounts historically settled through this sub-account, OPG proposes to discontinue entries in the Nuclear Sub-Account as of the effective date of the payments amounts order in this proceeding.

The derivation of entries in the Hydroelectric Sub-Account is shown in Ex. H1-1-1, Table 3, with a $6.7M credit entry for 2023 and a $3.0M credit entry for 2024. Hydroelectric ancillary services revenue in 2023 and 2024 was higher than the reference amount because of higher regulation service and operating reserve revenues, partially offset by lower reactive support revenue. The derivation of entries in the Nuclear Sub-Account is shown in Ex. H1-1-1, Table 3, with a $2.0M credit entry for 2023 and a $1.1M credit entry for 2024. The reasons for these variances are discussed in Ex. G2-1-2.

5.3 Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 along with OPG's hydroelectric incentive mechanism ("HIM") and has been approved in all subsequent OPG applications. Until the effective date of the payments amounts order in this proceeding, the account records a credit to ratepayers of 50% of OPG's HIM revenues above an OEB-specified threshold, set at $54.5M based on the forecast of HIM revenues reflected in the hydroelectric payment amounts approved in EB-2013-0321.

There were no additions to the account in 2023 and 2024 as actual HIM revenues of $14.8M in 2023 and $28.4M in 2024 were below the threshold, as shown in Ex. H1-1-1, Table 4.

For the reasons discussed in Ex. E1-2-1, Section 5.5, as of the effective date of the payment amounts order in this proceeding, OPG proposes to eliminate the sharing of HIM revenues exceeding the forecast HIM revenues and therefore proposes to terminate this account.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. This account records the financial impact of foregone production at the regulated hydroelectric facilities listed in Ex. E1-1-1 Appendix 1,[14] due to surplus baseload generation ("SBG") conditions. The amounts recorded in the account are net of avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates. In EB-2010-0008, the OEB concluded that the approach used to address the impact of SBG conditions on OPG's hydroelectric production forecast would be to "capture the impacts of all SBG through a variance account, with no allowance built into the [hydroelectric production] forecast."[15]

For the same reasons as noted in Section 5.1 with respect to the Hydroelectric Water Conditions Variance Account, the 27 small regulated hydroelectric facilities that comprise less than 2% of total regulated hydroelectric production are excluded from the scope of this account.

Entries in the account have been and, as of the effective date of the payment amounts order in this proceeding, are proposed to continue to be calculated by multiplying the foregone production volume due to SBG conditions (in MWh), determined as per below, by the approved regulated hydroelectric payment amount in effect, net of the avoided GRC costs. The account is also proposed to continue recording any production related variances in amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal and in the amounts payable to the Government of Quebec for water rentals, as a result of foregone production due to SBG conditions. Additional details on the GRC, water rental and similar costs can be found in Ex. F1-4-1.

[14] Following the May 1, 2025 implementation of the Renewed Market, under the revised SBGVA methodology approved in EB-2023-0336, no entries to this account are made for the Calabogie GS as it is an embedded generator that does not have a nodal price.

[15] Decision with Reasons, EB-2010-0008, March 10, 2011, p. 22.

Up to and including April 30, 2025, foregone production due to SBG conditions has been calculated as set out in the EB-2020-0290 Payment Amounts Order,[16] by starting with the total volume of spill and subtracting the volume of spill due to:

- water conveyance constraints (e.g., the Sir Adam Beck Generating Station tunnel capacity constraints);
- production capability constrains (e.g., unit outages; operating regulatory requirements etc.);
- market constraints (i.e., IESO dispatch constraints; market or transmission system); and
- contractual obligations (e.g., regulation service).

The remaining spill volume was identified as potential SBG spill. SBG conditions were considered to be present when the uniform market price fell below the GRC price threshold. The SBGVA entries were calculated using the volume of spill remaining after excluding the spill amounts incurred by OPG that was not attributable to the impact of SBG conditions.

On May 1, 2025, the IESO implemented its market renewal program ("MRP"). Pursuant to the OEB's Decision and Order in EB-2023-0336, OPG received approval to record entries to the SBGVA upon the implementation of MRP until the effective date of the payment amounts order in this proceeding, based on a revised methodology that addresses the impacts of the Renewed Market on OPG's compensation for foregone production due to global and local SBG.[17] OPG proposes to continue to use this methodology, as further discussed in Ex. E1-2-1, Section 4.3, to record entries to this account as of the effective date of the payment amounts order in this proceeding.

The derivation of account entries for 2023 and 2024 is shown in Ex. H1-1-1, Table 5. Actual foregone production due to SBG conditions was approximately 977 GWh in 2023 and 350

[16] EB-2020-0290 Payment Amounts Order, App. E, pp. 5-6.

[17] Additionally, in accordance with the OEB-approved EB-2023-0336 settlement proposal, OPG is recording, following the May 1, 2025 implementation of the Renewed Market and until the effective date of the payment amounts order in this proceeding, a credit entry of $0.6M per month to offset debit additions to the SBGVA. OPG also credits the SBGVA when Real-Time Make Whole Payments are received concurrently with an SBGVA entry at the resource level, with the credited amount limited to the lesser of the two, as discussed in Ex. E1-2-1.

GWh in 2024. Net of avoided GRC and related costs, the resulting debit entries in the account were $29.7M in 2023 and $10.6M in 2024.

Pursuant to the OEB-approved EB-2023-0336 settlement proposal, this Application is providing the stipulated information in support of the requested clearance of the SBGVA amounts in Attachments 3 and 4.[18]

5.5 Income and Other Taxes Variance Account (OPG)

The Income and Other Taxes Variance Account (OPG) was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account records and, as of the effective date of the payment amounts order in this proceeding is proposed to continue to record, the financial impact on OPG's revenue requirements of the following:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario)), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation ("OEFC") that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*;
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and
- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

[18] Information as set out in EB-2023-0336, Ex. L-H-SEC-04, Attachment 1 and Ex. L-H-SEC-05, Attachment 1 with additional information described at p. 15 of the EB-2023-0336 settlement proposal (EB-2023-0336, Ex. O1-1-1).

The account does not record the impact of the above in relation to the Scientific Research and Experimental Development investment tax credits ("SR&ED ITCs") and the income taxes payable thereon for OPG's nuclear facilities for taxation periods effective June 1, 2017. Such impacts are recorded in the SR&ED ITC Variance Account established in EB-2016-0152 effective June 1, 2017 and subsequently continued in EB-2020-0290.

The account is not proposed to include the revenue requirement impact of the Clean Electricity Investment Tax Credits ("CEITCs") that may be available to OPG's regulated facilities. Instead, the Application proposes to record any such impacts in applicable accounts as follows: the CRVA for CRVA-eligible projects, the NDVA for NDVA-eligible projects, and the proposed new Clean Electricity ITC Variance Account (OPG) for the remaining eligible expenditures (Section 7.3). Clean Electricity Investment Tax Credits are discussed in Ex. F4-2-1 Section 3.6.

Entries into the account are recorded relative to the income tax provision and the underlying inputs reflected in OPG's approved revenue requirement for the corresponding year. For the regulated hydroelectric facilities, until the effective date of the payment amounts order in this proceeding, the reference amounts used in determining variances are those reflected in the average 2014 and 2015 income tax provision approved by the OEB in EB-2013-0321, as adjusted for the removal of the application of OPG's regulated nuclear facilities' tax loss to the regulated hydroelectric facilities in 2015. As of the effective date of the payment amounts order in this proceeding, the Application proposes that the reference amounts used in determining any such variances be the corresponding 2027-2031 annual income tax provisions detailed in Ex. F4-2-1, Table 3b. This approach reflects the proposed hydroelectric rate-setting framework for the 2027-2031 term, whereby such annual income tax provision is included in the determination of the forecast capital-related revenue requirements ("CRRR") underpinning the proposed custom capital factor ("C-factor"). The hydroelectric rate-setting proposal is discussed in Ex. A1-3-2, Section 2.0, with the potential resulting interaction between the Income and Other Taxes Variance Account (OPG) and the Global Hydroelectric Capital Variance Account addressed in Ex. A1-3-2, Section 2.3.5.[19]

[19] Any additions to the Income and Other Taxes Variance Account will be calculated without duplication with other accounts that may be impacted such as the CRVA.

For OPG's nuclear facilities, the reference amount used in determining variances is the corresponding annual income tax provision reflected in OPG's nuclear revenue requirement approved by the OEB. The Application proposes to continue this approach as of the effective date of the payment amounts order in this proceeding. The forecast annual income tax provision for OPG's nuclear facilities for the IR term is detailed in Ex. F4-2-1, Table 3d.

OPG recorded five entries to the variance account in 2023 and 2024, totaling a net credit of $5.2M in 2023 and a net credit of $2.3M in 2024, as follows:

1) Credit entries in 2023 and 2024 related to a capital cost allowance ("CCA") rule change pursuant to the passing of Bill C-97, the *Budget Implementation Act, 2019, No. 1* in 2019, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018, referred to as accelerated investment incentive property ("AIIP").[20] In 2023 and 2024, the entries were applicable to the regulated hydroelectric facilities only, since the impact of this change for OPG's nuclear facilities was reflected in the EB-2020-0290 nuclear revenue requirements. Impacts of this CCA rule change is reflected in the forecast revenue requirement for the regulated hydroelectric facilities beginning in 2027;
2) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2017 taxation year from 75% to 100%, which, for the regulated nuclear facilities, was pro-rated for the period prior to the June 1, 2017 effective date for the SR&ED ITC Variance Account, based on the resolution of the 2017 income tax audit in 2023;
3) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2018 taxation year from 75% to 100% for the regulated hydroelectric facilities, based on the resolution of the 2018 income tax audit in 2023;
4) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2019 taxation year from 75% to 100% for the regulated hydroelectric facilities, based on the resolution of the 2019 income tax audit in 2024; and
5) A debit entry related to a reduction to the rate for the Ontario Research and Development Tax Credit from 4.5% to 3.5% of qualifying expenditures, effective June 1, 2016. This

[20] The entries do not include the impacts on projects subject to the CRVA or the NDVA, which are recorded in the respective accounts as part of the total CCA variances for those projects.

entry applies to the regulated hydroelectric facilities only, as the impact of this change for the nuclear facilities was reflected in the EB-2020-0290 nuclear revenue requirements.

The above entries are the same in nature and calculation as the equivalent entries previously recorded in the account. Entry 1) continues to be calculated by applying the accelerated CCA rules to the forecast capital additions reflected in the EB-2013-0321 regulated hydroelectric revenue requirements, using the percentage of eligible actual regulated hydroelectric projects (for the corresponding year) as a proxy. Entries 2), 3), and 4) recognize a credit to ratepayers of an additional 25% of the benefit of SR&ED ITCs that were previously credited to ratepayers at 75% in relation to 2014 and 2015 through the EB-2013-0321 payment amounts. SR&ED ITCs are discussed further in Ex. F4-2-1, Section 3.5. The derivation of the entries is shown at Ex. H1-1-1, Table 6.

5.6 Capacity Refurbishment Variance Account

The CRVA was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account was established pursuant to section 6(2)4 of O. Reg. 53/05 to record the financial impacts of variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments underpinning the revenue requirement that was approved by the OEB, including for the Darlington Refurbishment Program ("DRP"). As required by O. Reg. 53/05, section 6(2)4, the account includes assessment costs and pre-engineering costs and commitments.

There are some differences in the approved and proposed methodologies for recording additions to the account between OPG's regulated hydroelectric facilities and OPG's nuclear facilities, reflecting the differences in the respective rate-setting frameworks, as discussed below.

5.6.1 Regulated Hydroelectric

As set out in the EB-2020-0290 Payment Amounts Order, until the effective date of the payment amounts order in this proceeding, the CRVA records entries for the regulated hydroelectric facilities relative to the annual reference amount of $1.0M, being the $0.9M reflected in the OEB-approved revenue requirement for 2014 and 2015 in EB-2013-0321 as escalated by the price-cap index applied to adjust OPG's hydroelectric payment amounts approved by the OEB for 2018 through 2021. The EB-2020-0290 Payment Amounts Order also stipulates that effective January 1, 2022 and until the effective date of the payment amounts order in this proceeding, OPG is entitled to recover amounts recorded in the CRVA in relation to the regulated hydroelectric facilities to the extent that total capital in-service additions for these facilities (including any CRVA-eligible projects) from January 1, 2022-December 31, 2026 exceed the total funding available for capital expenditures through the regulated hydroelectric payment amounts established in the proceeding. The EB-2020-0290 Payment Amounts Order prescribed that such annual capital funding implicit in the regulated hydroelectric payment amounts be $153.0M, as determined by escalating the average 2014 and 2015 OEB-approved depreciation for the regulated hydroelectric facilities of $143.3M in EB-2013-0321 by the price-cap index applied to adjust OPG's hydroelectric payment amounts approved by the OEB for 2018 through 2021.[21] OPG is not seeking clearance of the hydroelectric balances in the CRVA in this Application. Consistent with the approach taken in EB-2020-0290, OPG proposes to defer such clearance to a future application, which would provide the necessary details to support an assessment of the recoverability of any such amounts recorded over the full 2022-2026 period in accordance with the above methodology.[22]

As discussed in Ex. A1-3-2, Section 2.0, the Application proposes to set payment amounts for the prescribed hydroelectric facilities using a price-cap index Custom IR framework, consistent with the approach applied for the 2017-2021 period in EB-2016-0152, but with the addition of the C-factor, among others. CRRR forecasts underpinning the 2027 test year and those that form the basis of the C-factors proposed from the 2028-2031 period – as shown in Ex. A1-3-

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[21] EB-2020-0290 Payment Amounts Order, App. E, pp. 8-9.

[22] For the same reason, OPG did not seek clearance of the 2022 hydroelectric account additions in the CRVA in EB-2023-0336.

2, Chart 6, line 4 – include the capital-related revenue requirement impacts of forecast CRVA-eligible projects. Therefore, as discussed in Ex. A1-3-2, Section 2.3.5, the Application proposes to record entries in the CRVA for capital costs for the regulated hydroelectric facilities relative to the forecast revenue requirement impact of the CRVA-eligible projects as reflected in the forecast CRRR underpinning the C-factor. Chart 1 below summarizes these proposed capital-related reference amounts, which are further detailed in Attachment 5. The projects underpinning the reference amounts in Chart 1 are identified in Ex. D1-1-2, Tables 1, 2a, 2b, 5 and 5b, in the respective "CRVA Eligible" columns.[23]

Chart 1 – Hydroelectric CRVA Proposed Capital Related Reference Amounts ($M)

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount[1]	(6.8)	63.3	171.6	231.1	277.9	737.1

[1]Refer to Attachment 5 for the derivation of the 2027-2031 annual reference amounts.

As discussed in Section 7.2 below and detailed in Ex. A1-3-2, Section 2.3.5, the Application proposes establishing a Global Hydroelectric Capital Variance Account ("GHCVA") that is asymmetric in favour of ratepayers, wherein an amount could be credited to ratepayers if the CRRR determined based on actual capital in-service additions over the 2028-2031 period is less than the forecast CRRR underpinning the C-factor during these years. As set out in in Ex. A1-3-2, Section 2.3.5, to address the interaction between the CRVA and the GHCVA, the following limitations would apply to the CRVA, as of the effective date of the payment amounts order in this proceeding: [24]

- The recoverability of the net debit entries in the CRVA for the regulated hydroelectric facilities over the 2028-2031 period would be limited to an amount, if any, by which the actual CRRR exceeds the forecast CRRR; and

[23] All of these projects have a total cost of at least $10M; OPG does not propose to track any regulated hydroelectric or nuclear capital costs in the CRVA for projects with a total cost of less than $10M.
[24] Any additions to the CRVA will be calculated without duplication with other accounts that may be impacted such as the Income and Other Taxes Variance Account.

- The refundability of the net credit entries in the CRVA for the regulated hydroelectric facilities over the 2028-2031 period would be limited to an amount, if any, by which the actual CRRR is below the forecast CRRR.

These thresholds would be evaluated in aggregate on a cumulative basis over the 2028-2031 period. They would not apply to the 2027 CRVA entries as there would be no GHCVA entries in 2027.

The revenue requirement impact of actual capital costs for the regulated hydroelectric projects subject to the CRVA will include the impact of any CEITCs associated with such projects, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

The Application proposes to record entries in the CRVA for eligible non-capital costs for the regulated hydroelectric facilities during the IR term relative to such forecast costs reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB. Such forecast eligible non-capital costs for 2027 are $25.3M.[25]

Nuclear

For OPG's regulated nuclear facilities, the variances recorded in the CRVA are determined as between the revenue requirement impact of actual capital and non-capital costs for eligible projects and the corresponding forecast amounts included in OPG's annual nuclear revenue requirements approved by the OEB. The Application proposes to continue this method as of the effective date of the payment amounts order in this proceeding.

Chart 2 below summarizes the proposed capital-related reference amounts, which are further detailed in Attachment 6 (for the Pickering Refurbishment Program), Attachment 7 (for the Darlington Refurbishment Program) and Attachment 8 (for all other eligible projects identified in this Application). Other than the Pickering Refurbishment Program ("PRP") and the Darlington Refurbishment Program ("DRP"), the projects underpinning the reference amounts

[25] Ex. F1-3-1, Table 1, Note 4.

in Chart 2 are identified in Ex. D2-1-3, Tables 1a-1c, 2a-2g and 5a-5d, in the respective "CRVA Eligible" columns.

Chart 2 – Nuclear CRVA Proposed Capital Related Reference Amounts

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount - Pickering Refurbishment Program[1]	(72.7)	(170.4)	(297.9)	(370.1)	329.5	(581.5)
2	Annual Reference Amount - Darlington Refurbishment Program, excluding D2O Storage[2]	1,214.1	1,201.5	1,184.0	1,162.2	1,138.4	5,900.2
3	Annual Reference Amount - Other Eligible Nuclear Projects[3]	10.1	65.5	67.7	153.2	273.3	569.8

[1] Refer to Attachment 6 for the derivation of the 2027-2031 annual reference amounts.
[2] Refer to Attachment 7 for the derivation of the 2027-2031 annual reference amounts.
[3] Refer to Attachment 8 for the derivation of the 2027-2031 annual reference amounts.

Chart 3 below summarizes the proposed non-capital reference amounts, being the corresponding forecasts reflected in the proposed nuclear revenue requirements in this Application.

Chart 3 – Nuclear CRVA Proposed Non-Capital Related Reference Amounts

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount - Pickering Refurbishment Program[1]	100.3	94.1	84.9	52.7	46.5	378.5
2	Annual Reference Amount - Darlington Refurbishment Program[2]	0.0	0.0	0.0	0.0	0.0	0.0
3	Annual Reference Amount - Other Eligible Nuclear Projects[3]	8.7	0.0	4.7	4.3	4.4	22.1

[1] Refer to Ex. F2-8-1, Table 1, line 2, cols. (h) to (l).
[2] Refer to Ex. F2-7-1, Table 1. line 4, cols. (h) to (l).
[3] Col. (a) is the sum of Ex. F2-3-1, Table 1, col. (h), lines 13, 15, and amounts shown for 2027 in Note 3 therein. Cols. (b) to (e) from Ex. F2-3-1, Table 1, Note 3 for the respective years.

The revenue requirement impact of actual capital costs for OPG's nuclear projects subject to the CRVA will include the impact of any CEITCs associated with such projects, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

This Application seeks to clear the entirety of the nuclear CRVA balance as at December 31, 2024, including the DRP-related amounts previously deferred from disposition in EB-2018-0243, EB-2020-0290 and EB-2023-0336.

5.6.2.1 Darlington Refurbishment Program

As discussed in Ex. D2-2-1, OPG is nearing the end of the DRP, having successfully returned to service Units 2, 3 and 1 and forecasting to return Unit 4 to service in April 2026, ahead of the high confidence schedule. There have been no material changes to the scope of the DRP, and OPG expects the final cost of the DRP to be within the $12.8B budget previously approved by the OEB. Additionally, in order to facilitate an efficient regulatory review of the project in this proceeding, OPG commits not to seek recovery of any unlikely actual costs over $12.8B in any future proceeding. The total expenditures over the life of the DRP, including amounts forecast for 2025 and 2026, are summarized in Ex. D2-2-3, Table 1a.

The OEB-approved Settlement Proposal in EB-2020-0290 provides the following:

> The OEB will review the prudence of any amounts sought by OPG in excess of the $12.8B total, the appropriateness of any future material changes to the scope of the DRP and any corresponding changes in contracts, when OPG seeks disposition of the actual DRP costs through the Capacity Refurbishment Variance Account.[26]

The above settlement terms are consistent with the principles of the OEB's findings in the EB-2016-0152 Decision and Order with respect to the Unit 2 refurbishment, which stated the following:

> The OEB will not micromanage the DRP, but rather will hold OPG accountable to deliver the DRP on time and on budget. If OPG were to face CRVA scrutiny for each component part of the Unit 2 project, it may lead to unintended consequences and lessen the ability of OPG to deal with issues as they arise. As OPG argues convincingly in its reply submission, the refurbishment of Unit 2 is a single integrated project, not a web of independent projects. It must be managed on a holistic, dynamic basis, where "higher cost may be incurred in one area to address a risk or resolve an issue in another area, which when taken as a whole, is to the benefit of ratepayers." At the end of the day, it is OPG's responsibility to deliver the Unit 2 project (and the campus plan projects) within the budget envelope

[26] Decision and Order, EB-2020-0290, November 15, 2021, p. 86.

> approved in this proceeding … OPG should have some flexibility doing so.[27]

As OPG is committing to the recovery of any final cost of the DRP to be within the approved budget of $12.8B, the Application is seeking disposition of the DRP-related debit balance of $170.2M (inclusive of interest) recorded in the CRVA as at December 31, 2024.[28,29] This balance includes entries made (i) prior to June 1, 2017 relative to the reference amounts reflected in the EB-2013-0321 nuclear revenue requirements; (ii) for the period June 1, 2017-December 31, 2021, relative to the reference amounts reflected in the EB-2016-0152 nuclear revenue requirements; and (iii) beginning January 1, 2022, relative to the reference amounts reflected in the EB-2020-0290 nuclear revenue requirements. These entries arise from over- and under-variances in the amounts and/or timing of capital in-service additions (and their tax effects) and non-capital costs that collectively form the DRP, relative to the forecasts reflected in the respective OEB-approved revenue requirements.

The year-end 2024 DRP-related balance in the CRVA comprises net debit additions totaling $175.6M for the capital portion[30] and net credit additions of $11.5M for the non-capital portion,[31,32] all recorded over the 2016-2024 period.[33] The derivations of the entries are shown in Ex. H1-1-1, Table 16 (capital portion) and Ex. H1-1-1, Table 15 (non-capital portion). These tables also show projected account entries for 2025 and 2026, being net debit additions totaling $106.6M, provided in support of an efficient regulatory review of the project in this proceeding.

The year-end 2024 net debit additions for the DRP-related capital portion include net debit additions of $61.6M over the 2016-2019 period, net credit additions of $126.2M over the 2020-2021 period and net debit additions of $240.2M over the 2022-2024 period. For the 2016-2019

[27] Decision and Order, EB-2016-0152, December 18, 2017, p. 41.
[28] Ex. H1-1-1, Table 1, line 21, col. (c).
[29] Additionally, the Application seeks disposition of the remaining accumulated balances in the CRVA, wholly related to interest, for the Heavy Water Storage and Drum Handling Facility ("D2O Storage Project") and the impact of AIIP rules on DRP-related CCA amounts (Ex. H1-2-1, Table 2, lines 7 and 8, col. (f)).
[30] Ex. H1-1-1, Table 16, line 20, col. (l).
[31] Ex. H1-1-1, Table 15, line 7, col. (l).
[32] Non-capital additions exclude variances in DRP-related low and intermediate level waste variable expenses arising from the 2022 ONFA Reference Plan, which are captured in the Nuclear Liability Deferral Account.
[33] With the exception of the D2O Storage Project and the impact of AIIP rules on DRP-related CCA amounts, the DRP portion of the CRVA was most recently cleared in EB-2016-0152, based on the year-end 2015 balances.

period, the entries are driven primarily by higher amounts placed into service for several Early In-Service and Safety Improvement Opportunities projects and a shorter useful life applied to the retube & feeder replacement tooling used for removal activities[34], relative to the depreciation assumptions underpinning the forecasts reflected in the OEB-approved revenue requirements in EB-2016-0152; these impacts are partially offset by the tax impact of higher actual amounts for CCA and other deductions. For the 2020-2021 period, the entries are driven primarily by a later return to service of Unit 2 in June 2020, compared to the EB-2016-0152 forecast assumption of February 2020. For the 2022-2024 period, the entries are driven primarily by an earlier return to service of Unit 3 in July 2023, compared to the EB-2020-0290 forecast assumption of January 2024, and an earlier return to service of Unit 1 in November 2024, compared to the EB-2020-0290 forecast assumption of April 2025.

The year-end 2024 net credit additions for the DRP-related non-capital portion include net credit additions of \$19.4M over the 2016-2021 period and net debit additions of \$7.9M over the 2022-2024 period. For the 2016-2021 period, the entries are driven primarily by changes in timing and amounts of removal costs due to shifting refurbishment schedules and modified project scopes, among others. For the 2022-2024 period, the variances driving the entries are discussed in Ex. F2-7-1.

Over the IR term, it is proposed that the CRVA record the revenue requirement impact of any variances in the amount and/or timing of the final capital in-service additions for the DRP, subject to OPG’s commitment not to seek recovery of any costs that exceed the \$12.8B budget. The entries would then cease upon the effective date of a subsequent payment amounts order that reflects the balance of such actual in-service additions in the payment amounts.

5.6.2.2 Other Nuclear Initiatives

For non-DRP nuclear initiatives, the Application seeks disposition of net debit entries totaling \$62.1M in 2023 and \$6.5M in 2024 for the non-capital portion and net debit entries totaling

[34] As re-affirmed by the depreciation study in EB-2020-0290, Ex. F4-1-1, Attachment 1, p. 19 and the depreciation study filed in this proceeding Ex. F4-1-1, Attachment 1, p. 4-4.

$2.5M in 2023 and $2.7M in 2024 for the capital portion. The derivation of the entries is shown in Ex. H1-1-1, Table 13 (non-capital portion) and Ex. H1-1-1, Table 14 (capital portion).

The non-capital entries are driven primarily by variances from the following initiatives, which are further discussed below:

- Fuel Channel Life Extension Project
- Fuel Channel Life Extension Related Ongoing Costs
- Pickering B Refurbishment Feasibility Assessment
- Darlington Steam Generator Primary Moisture Separators Replacement projects
- Optimization of Pickering Shutdown
- Fuel Channel Life Management Phase V Project

The capital entries are driven primarily by the Darlington Steam Generator Primary Moisture Separators Replacement projects.

There are also minor variances recorded in respect of the final costs associated with the Pickering Extended Operations initiative, the Darlington Unit 3 Fuel Channel Component Retrieval Project and the Darlington Annulus Spacer Life Management Project, all of which have been completed within their respective budgets.

<u>Fuel Channel Life Extension Project</u>

Under this initiative, OPG performed work to update assessments of degradation mechanisms on fuel channels to demonstrate their fitness for service and capability to operate until a planned nuclear station end of life. It most recently focused on supporting the operation of the Pickering units to 295,000 equivalent full power hours ("EFPH"). The initiative was substantially completed in 2024 within budget. Additional research and testing, along with project close out activities performed in 2023 and 2024 relative to the forecast amounts reflected in the EB-2020-0290 nuclear revenue requirements gave rise to the non-capital debit entry of $3.0M in 2023 and credit entry of $0.1M in 2024.

Fuel Channel Life Extension Ongoing Costs

The fuel channel life extension ongoing (consequential) costs represent expenditures incurred for incremental work required to enable the operation of fuel channels and other major components, such as steam generators, until a nuclear station's planned end of life that is beyond original design targets. The non-capital debit entries of $28.0M in 2023 and $0.8M in 2024 were primarily driven by costs incurred for chemical cleaning performed in Pickering Unit 8 to address boiler (steam generator) level oscillations that can limit station operations. This work mitigated risk of a unit derate in support of Pickering's extended operations until September 2026, as discussed further in Ex. F2-3-3, Section 3.0.

Pickering B Refurbishment Feasibility Assessment

In September 2022, the Province of Ontario ("Province") requested OPG to update its previous feasibility assessment for refurbishing Pickering Units 5-8. In response, OPG assessed whether the refurbishment would be technically, economically, and operationally viable. In August 2023, OPG's Board of Directors approved the feasibility assessment. Subsequently, the Province announced their support in January 2024 for OPG to proceed with the next steps toward refurbishing Units 5-8, with OPG's Board of Directors ultimately approving OPG to proceed with the refurbishment in November 2025. The feasibility assessment work was not anticipated in the EB-2020-0290 nuclear revenue requirements. Non-capital costs of $0.2M in 2022 and $17.8M in 2023 incurred to carry out this assessment were recorded in the account as debit entries.[35] The feasibility assessment is further discussed in Ex. D2-3-4, Section 2.1.1 and Ex. F2-1-1, Section 5.2.

Darlington Steam Generator Primary Moisture Separators Replacement

OPG is replacing the primary moisture separators in the steam generators of all four Darlington units after inspections revealed irreversible damage in the form of increased degradation from flow-assisted corrosion. There were no forecast amounts included in the EB-2020-0290 nuclear revenue requirements associated with this work. The resulting non-capital debit entries to the account were $4.5M in 2023 and $3.8M in 2024, for costs incurred in connection with

[35] Disposition of the $0.2M debit entry recorded in 2022 in respect of the Pickering B Refurbishment Feasibility Assessment was deferred in EB-2023-0336.

the removal of existing primary moisture separators and associated support structures in the Darlington Units 1 and 4 steam generators, respectively. The resulting capital debit entries to the account were $3.4M in 2023 and $12.9M in 2024, representing the revenue requirement impacts of the in-service additions for the new primary moisture separators installed in two steam generators at Darlington Unit 3 and all steam generators at Darlington Unit 4, respectively. For further details on the project, refer to Ex. D2-1-3.

<u>Optimization of Pickering Shutdown</u>

The objective of the Optimization of Pickering Shutdown initiative, presented in EB-2020-0290, was to safely optimize the shutdown of the Pickering station by operating all six then-operating units until September 2024, five of the six units through 2024, and the remaining four units until December 2025, subject to the approval by the Canadian Nuclear Safety Commission ("CNSC"). The clearance of the account entries related to this initiative was deferred in EB-2023-0336, with large portions of the associated work ongoing at the time. With most of this work completed by the end of 2024 and the initiative tracking to completion below the budget of $50M presented in EB-2020-0290, the Application is seeking to recover the related non-capital net debit additions totaling $0.9M over the 2020-2024 period.[36] Further details of this initiative can be found in Ex. F2-1-1, Section 4.0.

<u>Fuel Channel Life Management Phase V Project</u>

This project was identified after EB-2020-0290 and gave rise to non-capital debit entries of $1.1M and $5.3M in 2023 and 2024. This project is required to demonstrate fitness-for-service and capability of the units to support current and extended EFPH targets at Darlington and Pickering. As discussed in Ex. F2-3-1, for Darlington, work performed is driven by additional pressure tube burst tests, updates to pressure tube fracture toughness models and uncertainty analysis. As discussed in Ex. F2-1-1, for Pickering, work performed will support extending the current aging limits on fuel channel components and support post-refurbishment operations for Units 5-8.

[36] The net debit additions of $0.9M represent the sum of: Ex. H1-1-1, Table 13, line 28, cols. (a)-(b) and EB-2023-0336, Ex. H1-1-1, Table 15, line 26, cols (a)-(c).

5.7 Pension and OPEB Cost Variance Account (OPG)

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090 and has been continued in subsequent proceedings. As applicable, this account records the difference between (i) the pension and other post-employment benefit ("OPEB") costs, plus related income tax payments in lieu, reflected in the revenue requirement approved by the OEB; and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference are calculated on an accrual basis using the same accounting standards as those used to derive the reference amount. The Application proposes to continue this methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding, for OPG's nuclear and regulated hydroelectric facilities.

For its nuclear facilities, OPG resumed recording additions to the account effective January 1, 2022.[37] These additions are identified in the Post-2021 Additions component of the account balance. There are no account additions being recorded for the regulated hydroelectric facilities over the 2022-2026 period as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect did not include pension and OPEB accrual costs.[38] As discussed in Ex. F4-3-2, the proposed revenue requirement for the regulated hydroelectric facilities for 2027 reflects pension and OPEB accrual costs.

The derivation of the $218.7M credit entry in 2023 and the $94.4M credit entry in 2024 for the nuclear facilities is shown in Ex. H1-1-1, Table 7b. These additions reflect actual pension and OPEB costs that were lower than the forecast amounts reflected in the corresponding EB-2020-0290 revenue requirements. Pension and OPEB costs are discussed in Ex. F4-3-2.

All other historical balances in the account will be amortized by the end of 2026 as approved in prior proceedings. No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

[37] Payment Amounts Order, EB-2020-0290, App. E, pp.10-11.
[38] Payment Amounts Order, EB-2020-0290, App. E, pp.10-11.

5.8 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the differences between the amounts approved for recovery or repayment in the hydroelectric deferral and variance accounts and the actual amounts recovered or repaid based on the actual regulated hydroelectric production and approved riders. Pursuant to the OEB's orders, the account also captures the transfer of the hydroelectric portions of the balances remaining in other accounts as they expire from time to time. The Application proposes to continue the above methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the $1.6M and $2.6M debit additions to the account for 2023 and 2024, respectively, is shown in Ex. H1-1-1, Table 8. There were no transfers from expiring accounts in 2023 or 2024.

5.9 Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was originally approved in EB-2013-0321 and has been approved in all subsequent OPG applications. As Ontario Regulation 124/02, s. 7, allows deductions to GRC for eligible capacity of new, redeveloped, or upgraded stations, this account records the cost impact of a GRC deduction, once approved by the Ontario Ministry of Natural Resources, pertaining to production increases at OPG's Sir Adam Beck stations due to the operation of the Niagara tunnel that was completed in 2013.

As no decision on the GRC deduction has been issued by the Ministry of Natural Resources to date, there have been no amounts recorded in the account since its inception.

The Application is seeking to expand the scope of this account in two ways, as of the effective date of the payment amounts order in this proceeding, with resulting variances over the IR term measured against the forecast GRC costs reflected in the 2027 regulated hydroelectric revenue requirement.

First, the Application proposes this account be expanded to apply to all of OPG's regulated hydroelectric facilities with respect to potential GRC deductions that may be approved by the Ontario Ministry of Natural Resources under Ontario Regulation 124/02 for eligible stations, so as to allow these amounts to be returned to ratepayers. While no GRC deductions are included in the GRC forecast, OPG expects to apply for GRC deductions for certain projects taking place during the 2027-2031 period, following project in-service and the required period of operations to determine the eligibility and magnitude of possible GRC deductions.

Second, the Application proposes that the scope of the account also capture the revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to OPG's prescribed hydroelectric assets under Section 92.1 of the *Electricity Act, 1998*. Any potential legislative or regulatory changes in this regard are not known and are beyond OPG's control. With actual and forecasted GRC expenses in the order of $300M to $360M annually (Ex. F1-4-1, Table 1), these costs constitute a material component of the regulated hydroelectric payment amounts.[39] The proposed treatment would also be consistent with the scope of the Income and Other Taxes Variance Account (OPG) related to payments in lieu of taxes to the OEFC, as GRC payments constitute a levy primarily payable to the OEFC and the Ontario Ministry of Finance. Further details on the GRC regime can be found in Ex. F1-4-1, with the 2027 forecast costs presented in Ex. F1-4-1, Table 1.

5.10 Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and has been continued in subsequent proceedings. As applicable, it records the difference between OPG's actual registered pension plan ("RPP") contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts underpinning the revenue requirement approved by the OEB.

[39] As discussed in Ex. A1-3-2, OPG has proposed that the GRC component of the 2027 regulated hydroelectric revenue requirement not be subject to the annual price-cap escalation for the duration of the IR term.

For its nuclear facilities, OPG ceased recording additions to the account effective January 1, 2022, as the EB-2020-0290 nuclear revenue requirements reflect pension and OPEB costs calculated on an accrual basis.[40] Account additions are being recorded for the regulated hydroelectric facilities over the 2022-2026 period, as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect included pension and OPEB amounts on a cash basis.[41] No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

For the regulated hydroelectric facilities, the variances recorded over the 2022-2026 period are calculated as between actual RPP contributions and OPEB payments (including the long-term disability benefit plan) attributed to the regulated hydroelectric facilities and such forecast amounts underpinning the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321.

The derivation of the credit additions of $15.6M in 2023 and $12.1M in 2024 for the regulated hydroelectric facilities is shown in Ex. H1-1-1, Table 7. These additions reflect actual RPP contributions and OPEB payments (including the long-term disability benefit plan) that were overall lower than the forecast amounts reflected in the EB-2013-0321 revenue requirement. The cash amounts for pension and OPEB are discussed in Ex. F4-3-2.

5.11 Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was approved in EB-2013-0321 and has been continued in subsequent OPG applications. As applicable, the account records differences between: (i) OPG's actual pension and OPEB costs for its prescribed generating facilities determined using the accrual accounting method applied in OPG's audited consolidated financial statements; and, (ii) OPG's actual registered pension

[40] Payment Amounts Order, EB-2020-0290, App. E, p. 12.
[41] Payment Amounts Order, EB-2020-0290, App. E, p. 12.

plan contributions and other post-employment benefit plan payments (including the long-term disability benefit plan) attributed to OPG's prescribed generating facilities.[42]

For the regulated nuclear facilities, OPG ceased recording additions to the account effective January 1, 2022, as the EB-2020-0290 nuclear revenue requirements reflect pension and OPEB costs calculated on an accrual basis.[43] Account additions are being recorded for the regulated hydroelectric facilities over the 2022-2026 period, as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect did not include pension and OPEB accrual costs and reflected pension and OPEB amounts on a cash basis.[44] No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

The derivation of the credit additions of $19.7M in 2023 and $10.8M in 2024 for the regulated hydroelectric facilities is shown in Ex. H1-1-1, Table 7. Pension and OPEB costs and cash amounts are discussed in Ex. F4-3-2. Included as Attachment 2 to that exhibit is Aon's independent actuary report on OPG's total accrual pension and OPEB costs determined in accordance with US GAAP for 2023 and 2024. As discussed in Ex. F4-3-2, OPG's total accrual pension and OPEB costs were attributed to the prescribed facilities using the same methodology as in the previous proceedings.

No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

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[42] As noted in prior proceedings, the continued recognition of amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset in OPG's financial statements in accordance with US GAAP requires that the period of deferring amounts recorded in the account related to OPEB not exceed five years from the time that they were incurred. For example, this means any such amounts recorded at the beginning of 2023 must commence recovery as of the beginning of 2028 to satisfy US GAAP criteria.
[43] Payment Amounts Order, EB-2020-0290, App. E, p. 13.
[44] Payment Amounts Order, EB-2020-0290, App. E, p. 13.

5.12 Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account

The Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account was established by the OEB on a generic basis in EB-2015-0040 and continued in EB-2020-0290. The account has three sub-accounts, as described below.

The Primary Sub-Account tracks amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for both OPG's regulated hydroelectric and regulated nuclear facilities. Beginning January 1, 2022, for the nuclear facilities only, the Primary Sub-Account also tracks the difference between actual pension and OPEB accrual costs[45] and OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) (i.e., cash payments). When the cumulative accrual amount (including amortization amounts from the Pension & OPEB Cash Versus Accrual Differential Deferral Account) exceeds the cumulative cash payments, the sub-account holds a credit balance and accrues carrying charges asymmetrically in favour of ratepayers in the Carrying Charges Sub-Account. The Contra Sub-Account records offsetting entries with the Primary Sub-Account to enable book-keeping with offsetting entries. Carrying charges do not apply to this sub-account. The Carrying Charges Sub-Account records interest at the OEB's prescribed Construction Work In Progress ("CWIP") rate. As tracking accounts, neither the Primary Sub-Account nor the Contra Sub-Account are subject to disposition. The Carrying Charges Sub-Account is subject to disposition.

The Application proposes to continue the above methodology for recording entries into the account as of the effective date of the payment amounts order in this proceeding, for OPG's nuclear and regulated hydroelectric facilities. This will include the difference, and the associated interest per above, between actual pension and OPEB accrual costs and such actual cash amounts for the regulated hydroelectric facilities, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

[45] The actual amount of pension and OPEB accrual costs is used as the basis for entries in the Primary Sub-Account to account for the interaction of this account with the Pension and OPEB Cost Variance Account.

The entries to the Primary Sub-Account were a credit of $24.1M in 2023 and a credit of $29.7M in 2024 for the regulated hydroelectric facilities, representing the OEB-approved amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account. For the regulated nuclear facilities, the entries to the Primary Sub-Account were a credit of $43.6M in 2023 and a credit of $122.8M in 2024, representing the sum of the OEB-approved amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the difference between actual pension and OPEB accrual costs and such actual cash payments for the respective year. The derivation of the entries and the associated cumulative balances are set out in Ex. H1-1-1, Table 7a.

The resulting credit additions to the Carrying Charges Sub-Account were $2.9M in 2023 and $4.0M in 2024 for the regulated hydroelectric facilities, and $14.8M in 2023 and $17.8M in 2024 for OPG's nuclear facilities.

No interest is being recorded on the balance of the Carrying Charges Sub-Account pursuant to the EB-2020-0290 Payment Amounts Order.

5.13 Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in EB-2014-0369 and continued in all subsequent OPG applications. The account records the difference between the annual revenue requirement impact of the original Niagara Tunnel Project rate base addition disallowance of $28.0M per EB-2013-0321 and the varied disallowance of $6.4M per EB-2014-0369. As the payment amounts for the regulated hydroelectric facilities set in EB-2020-0290 reflected the EB-2013-0321 disallowance and not the impact of the varied disallowance, the account continues to record the above difference during the 2022-2026 period. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect the impact of the varied disallowance.

The derivation of the $1.7M debit additions to the account in each of 2023 and 2024 is shown in Ex. H1-1-1, Table 9.

5.14 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. In accordance with section 5.2(1) of O. Reg. 53/05, this account records the revenue requirement impact on OPG's prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"), measured against the forecast impact reflected in the revenue requirement approved by the OEB.[46]

The nuclear revenue requirements approved in EB-2020-0290 reflected the approved 2017-2021 ONFA Reference Plan effective January 1, 2017 ("2017 ONFA Reference Plan"), which was the most recent approved ONFA reference plan at the time of the proceeding. Subsequent to the EB-2020-0290 proceeding, the Province approved the 2022-2026 ONFA Reference Plan effective January 1, 2022 ("2022 ONFA Reference Plan") and its attendant contribution schedule ("2022 ONFA Contribution Schedule"). The proposed IR term revenue requirements for OPG's nuclear facilities reflect the 2022 ONFA Reference Plan. The 2027-2031 ONFA Reference Plan ("2027 ONFA Reference Plan") is being developed and will be subject to approval by the Province after OPG submits it, expected in late 2026. OPG will continue to record entries in the account as of the effective date of the payment amounts order in this proceeding, once the 2027 ONFA Reference Plan is effective.[47]

Entries in the account are determined using the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities. As described in Ex. C2-1-1, the Application proposes to continue with such previously approved methodology in this proceeding. Consistent with the application of this methodology, for any year where there is a positive provision for the "lesser of Unfunded Nuclear Liabilities and Asset Retirement Cost" determined in OPG's approved capital structure approved by the OEB for such provision in

[46] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 6(2)).
[47] Any additions to the Nuclear Liability Deferral Account arising from the 2027 ONFA Reference Plan and such additions to any other accounts that may be impacted, such as the CRVA, will be calculated such that there is no duplication across the accounts.

setting the corresponding revenue requirement, the weighted average accretion rate used in setting the corresponding revenue requirement is used to determine the return on rate base component of any entries in the account. For any year where the provision for the "lesser of Unfunded Nuclear Liabilities and Asset Retirement Cost" in OPG's approved capital structure is set to zero (due to the Unfunded Nuclear Liability being negative), the weighted average cost of capital approved by the OEB in setting the corresponding revenue requirement is used to determine to the return on rate base component of any entries in the account.[48] The Application proposes to continue the above methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding.

OPG will be responsible for the nuclear waste management and decommissioning obligations arising for the DNNP facilities. Section 6(2)10.1 of O. Reg. 53/05 requires the OEB to ensure that OPG recovers all the costs it incurs in relation to its nuclear liabilities with respect to the DNNP facilities as they are reflected in OPG's audited financial statements.[49] Pursuant to the regulation, the Application proposes to establish a new deferral account to record these impacts, as discussed in Section 7.5 below, using the same methodology that the OEB has approved for the Bruce facilities. Accordingly, no amounts would be recorded for the DNNP facilities in the Nuclear Liability Deferral Account.

The debit entries to the account of $193.3M in 2023 and $187.5M in 2024 represent the revenue requirement impact on OPG's nuclear facilities related to changes in the nuclear liabilities arising from the approved 2022 ONFA Reference Plan. These entries were determined using the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities as reflected in the EB-2020-0290 revenue requirements. They were also calculated in the same manner as the equivalent entry for 2022, which formed part of the account balance approved in EB-2023-0336. The derivation of these additions is shown at Ex. H1-1-1, Table 17. This table also show projected account entries for 2025 and 2026, being net debit additions totaling $24.8M, provided in support of an efficient regulatory review of the balances.

[48] Payment Amounts Order, EB-2020-0290, App. E, p. 15; Ex. C2-1-1, Section 4.1.4.
[49] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

The revenue requirement impact of the 2022 ONFA Reference Plan recorded in the account reflects: i) the impacts of the associated change in the asset retirement obligation ("ARO") and asset retirement costs ("ARC") for OPG's regulated facilities recognized in OPG's financial statements at the end of 2021, ii) the impact of changes in the station-level segregated fund contribution schedule attendant to the 2022 ONFA Reference Plan ("2022 ONFA Contribution Schedule"), and iii) the nuclear liabilities' impacts of the extension of the accounting end-of-life ("EOL") date for Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024, effective December 31, 2020, which was subsequently reflected in the 2022 ONFA Reference Plan and became eligible to be recorded in the Nuclear Liability Deferral Account in accordance with O. Reg. 53/05.[50]

The impacts of the year-end 2021 ARO/ARC adjustment and the 2022 ONFA Contribution Schedule comprise a debit amount of $123.9M in 2023 and $119.5M in 2024 (Ex. H1-1-1, Table 17, line 15) and are further discussed in Ex. C2-1-1, Section 5.1.

The nuclear liabilities' impacts of the extension of the Pickering Units 1 and 4 EOL date reflected the associated year-end 2020 ARO/ARC adjustment recognized in OPG's financial statements and the change in the ARC depreciation expense due to the extended useful life. These impacts comprise a debit amount of $69.4M in 2023 and $67.9M in 2024 (Ex. H1-1-1, Table 17, line 16) and were anticipated in EB-2020-0290.[51,52] The derivation of these amounts is further discussed in Section 5.23 below. The change in the EOL date for Pickering Units 1 and 4 is discussed further in Ex. F4-1-1, Section 3.5.

No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

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[50] As discussed in Section 5.23 below, impacts of the Pickering Units 1 and 4 EOL date extension from changes to the non-ARC depreciation and amortization expense are recorded in the Impact Resulting from Optimization of Pickering Station End of Life Deferral Account.

[51] The Pickering Units 1 and 4 EOL date extension and its impacts were detailed during the course of the EB-2020-0290 proceeding, but due to the timing of preparing OPG's underlying business plan, were not included in the forecasts underpinning the approved payment amounts.

[52] OPG's responses to interrogatories in EB-2020-0290, which were completed after OPG had finalized the year-end 2020 financial information required to calculate these ARO/ARC impacts, projected a debit entry of $69.4M for 2023 and $67.9M for 2024 (EB-2020-0290, Ex. L-F4-01-Staff-271, Attachment 1, Table 2, line 17, cols. (b) and (c)).

5.15 Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 in accordance with section 5.4 of O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account records differences between the revenue requirement impacts arising from the actual non-capital costs and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities and such forecast amounts reflected in the revenue requirement approved by the OEB. This includes but is not limited to the costs of planning, preparation, and technology identification for the new facilities, as well as design, development and construction of the new facilities.[53]

The variance recorded in the account is calculated as between the revenue requirement impact of actual eligible non-capital and capital costs and firm financial commitments and such forecast amounts reflected in OPG's corresponding annual nuclear revenue requirement approved by the OEB. The Application proposes to continue this method of determining additions to the account as of the effective date of the payment amounts order in this proceeding.

The revenue requirement impact of actual capital costs for eligible projects will include the impact of any associated CEITCs, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

The account has been capturing entries related to the DNNP. With the exception of any true-up adjustments in connection with the periods prior to the asset transfer, no account additions related to the DNNP are expected to be recorded in the account following the transfer of the DNNP assets from OPG to DNNP LP, when the Darlington New Nuclear Project Variance Account re Development ("DNNPVARD") would begin to apply. DNNPVARD is discussed in Section 6.1 below.

[53] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 6(2)), to the extent the OEB is satisfied that the costs were prudently incurred and the firm financial commitment were prudently made.

With the DNNP Unit 1 forecast to enter rate base during the IR term, the Application proposes to clear DNNP-related account additions in this proceeding. Such credit entries of $8.1M in 2023 and $26.5M in 2024 primarily relate to the tax impacts of CCA and SR&ED qualifying expenditure deductions related to the project. The EB-2020-0290 revenue requirements did not reflect the DNNP or the associated tax deductions. The derivation of these additions is shown at Ex. H1-1-1, Table 20. Further details on the DNNP can be found at Ex. D2-4-1 to Ex. D2-4-10.

As noted in Ex. F2-1-1, Section 5.1, the proposed nuclear revenue requirements in the Application do not include non-capital or capital costs related to potential new nuclear generation facilities other than the DNNP, which will result in any such impacts incurred by OPG during the IR term being recorded in this variance account. The Application also proposes to defer the clearance of the year-end 2024 account balance related to the costs incurred to date in connection with these activities, which would allow such costs to be considered after these initiatives have been further advanced. The costs relate to advancing planning and preparation activities for potential new nuclear generation on OPG's sites, including the Wesleyville site, in line with the Province's plans for meeting Ontario's electricity demand.

5.16 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved in EB-2007-0905 to ensure that the actual difference between OPG's revenues and costs for the Bruce facilities is ultimately reflected in the payment amounts and riders and that OPG recovers its actual costs associated with the Bruce facilities, giving effect to the requirements of sections 6(2)9 and 6(2)10 of O. Reg. 53/05. The account has been approved in all subsequent OPG applications.

The account records differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The costs include nuclear liabilities' costs for the Bruce facilities.

The variance recorded in the account is determined by comparing (i) the quotient of the annual forecast amount of Bruce Lease net revenues reflected in the OEB-approved revenue requirement and the OEB approved nuclear production forecast (“rate of recovery”) for the corresponding year multiplied by OPG’s actual nuclear production for the year, and (ii) OPG’s actual revenues and costs in respect of the Bruce facilities. The Application proposes to continue this methodology for determining additions to the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the credit entries of $19.0M in 2023 and $89.2M in 2024 recorded in the account is shown in Ex. H1-1-1, Table 10. Bruce Lease net revenues are discussed in Ex. G2-2-1.

5.17 Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG)

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the differences between the amounts approved for recovery or repayment in nuclear deferral and variance accounts and the actual amounts recovered or repaid based on the actual nuclear production and approved riders. Pursuant to OEB’s orders, the account also captures the transfer of the nuclear portions of the balances remaining in other OPG accounts as they expire from time to time. The Application proposes to continue the above methodology for recording entries into the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the $6.1M and $1.2M credit additions to the account for 2023 and 2024, respectively, is shown in Ex. H1-1-1, Table 11. There were no transfers from expiring accounts in 2023 or 2024.

5.18 Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account was established in accordance with section 5.5 of O. Reg. 53/05 and approved in EB-2016-0152. The account records the difference between: (i) the total annual nuclear revenue requirement approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the nuclear payment amounts in each year ("the annual deferral amount"). According to O. Reg. 53/05, an annual deferral amount as determined by the OEB is recorded in the account from January 1, 2017 until the DRP ends (the "deferral period"). Section 6(2)12(iv) of O. Reg. 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account and shall authorize recovery of the account balance on a straight-line basis over a period not to exceed ten years commencing at the end of the deferral period.

The account has recorded the annual deferral amounts approved by the OEB since 2017. Pursuant to the EB-2016-0152 Payment Amounts Order, the approved annual deferral amounts recorded in the account are \$0 in 2017, \$0 in 2018, \$102.2M in 2019, \$390.6M in 2020, and \$0 in 2021.[54] Pursuant to the EB-2020-0290 Payment Amounts Order, the approved annual deferral amounts recorded in the account are \$19.0M in 2022, \$64.0 in 2023, \$0 in 2024, \$0 in 2025, and \$0 in 2026.[55]

With the DRP expected to return the last unit to service in 2026, no additions are anticipated to be required to the account as of the effective date of the payment amounts order in this proceeding. Section 5.5(2) of O. Reg. 53/05 stipulates that the deferral account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing, as approved by the OEB, compounded annually.

The Application seeks to recover the year-end 2024 account balance of \$677.4M over the maximum prescribed period of ten years[56], from January 1, 2027 to December 31, 2036.

5.19 Fitness for Duty Deferral Account

The Fitness for Duty Deferral Account was approved by the OEB in EB-2016-0152 and continued in EB-2020-0290. The account records OPG's costs to implement the CNSC Fitness for Duty program, which is a drug, alcohol, psychological and physical testing program for

[54] Payment Amounts Order, EB-2016-0152, App. H, p. 1.
[55] Payment Amounts Order, EB-2020-0290, App. E, p.19.
[56] In accordance with section 6(2)12(iv) of O. Reg. 53/05.

employees in nuclear facilities. Given uncertainties with respect to the cost of the program, no such forecasted amounts were included in either the EB-2016-0152 or EB-2020-0290 revenue requirements.

Given the conclusion of prior legal challenges regarding the Fitness for Duty requirements and the provisions tracking to be implemented by January 1, 2026, the Application seeks recovery of the debit balance of $2.5M, inclusive of interest, recorded in the account over the period of June 1, 2017 to December 31, 2024. The underlying account additions represent non-capital costs averaging $0.3M per year, related to program set-up and administration and testing based on reasonable grounds, for post-incident, and as follow up to return-to-duty for nuclear workers occupying safety critical or safety sensitive positions. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect the ongoing costs of the program.

5.20 SR&ED ITC Variance Account (OPG)

The SR&ED ITC Variance Account was approved in EB-2016-0152 and continued in EB-2020-0290. The account records the difference between actual SR&ED ITCs for OPG's nuclear facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the revenue requirement approved by the OEB, including the tax on the difference. For the reasons discussed in Ex. F4-2-1, Section 3.4, the Application proposes to continue this methodology for recording entries in the account for OPG's nuclear facilities, and to apply the same treatment to the regulated hydroelectric facilities, as of the effective date of the payment amounts order in this proceeding.

OPG recorded five entries to the account in 2023 and 2024, totaling a net credit of $18.0M in 2023 and a net credit of $5.5M in 2024, as follows:

1) A credit entry in 2023 and a debit entry in 2024 to record the difference between the estimated actual SR&ED ITCs (net of tax) attributed to OPG's nuclear facilities and the forecast SR&ED ITCs (net of tax) included in the corresponding OEB-approved nuclear revenue requirement for those years;

2) Credit entries in 2023 and 2024 for the true-up adjustments between the estimated actual and the final actual SR&ED ITCs (net of tax), as attributed to OPG's nuclear facilities, for the immediately preceding year based on the finalization of that year's income tax return;
3) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2017 taxation year from 75% to 100% for OPG's nuclear facilities, as prorated for the period after the effective date of the SR&ED ITC Variance Account of June 1, 2017, based on the resolution of the 2017 income tax audit in 2023;
4) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2018 taxation year from 75% to 100% for OPG's nuclear facilities, based on the resolution of the 2018 income tax audit in 2023; and
5) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2019 taxation year from 75% to 100% for OPG's nuclear facilities, based on the resolution of the 2019 income tax audit in 2024.

Entries 1) and 2) are the same in nature and calculation as the equivalent annual SR&ED ITC impact entries previously recorded in the account. Entries 3), 4) and 5) are the same in nature and calculation as the equivalent SR&ED ITC entries recorded in the Income and Other Taxes Variance Account in relation to resolution of prior year income tax audits, prior to the effective date of this account. They recognize a credit to ratepayers of 25% of the benefit of SR&ED ITCs that were previously credited to ratepayers at 75% in relation to 2017, 2018 and 2019 through the EB-2016-0152 payment amounts and subsequent additions to this account. SR&ED ITCs are discussed further in Ex. F4-2-1, Section 3.5. The derivation of the entries is shown in Ex. H1-1-1, Table 12.

5.21 Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account

The Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account was approved in EB-2018-0002 and continued in EB-2020-0290. Effective January 1, 2018, this account recorded the revenue requirement impact for the prescribed facilities arising from changes to nuclear liabilities and depreciation and amortization expense resulting from the Pickering station EOL date changes that came into effect on December 31, 2017. Pursuant to the EB-2020-0290 Payment Amounts Order, additions to this account ceased to be recorded effective January 1, 2022, as the impact arising from these EOL date changes was reflected in the revenue requirements approved in that proceeding.[57]

No interest is recorded in the account pursuant to the EB-2020-0290 Payment Amounts Order.

The December 31, 2024 balance in the account is expected to be fully amortized by December 31, 2026 pursuant to the OEB-approved settlement proposal in EB-2023-0336.[58] As such, the Application proposes to terminate this account as of the effective date of the payment amounts order in this proceeding and to transfer any remaining balance (expected to be nil) to the Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG).

5.22 Pickering Closure Costs Deferral Account

The Pickering Closure Costs Deferral Account was established in accordance with section 5.6 of O. Reg. 53/05. Effective January 1, 2021, this account records any employment-related costs and non-capital costs related to third party service providers incurred by OPG that arise from any Pickering closure activities. The regulation specifies that Pickering closure costs can be incurred before or after the closure of a Pickering unit but do not include costs that are eligible for reimbursement to OPG under the ONFA or have already been included in a payment amounts order, and are to be recorded in the account as they are reflected in OPG's audited financial statements approved by OPG's Board of Directors.

The additions recorded in the account are calculated as the difference between actual Pickering closure costs and any such forecast amounts reflected in the corresponding annual nuclear revenue requirement approved by the OEB. This account will continue to record additions as of the effective date of the payment amounts order in this proceeding, as

[57] Payment Amounts Order, EB-2020-0290, App. E, p. 18.
[58] Decision and Order, EB-2023-0336, App. A, Table 2, line 23.

necessary, in accordance with the regulation provisions.[59] The EB-2020-0290 revenue requirements did not reflect any Pickering closure costs.

The Application seeks recovery of the debit balance of $7.6M, inclusive of interest, recorded in the account over the period from January 1, 2021 to December 31, 2024. The underlying account additions of $1.0M in 2021, $1.8M in 2022, $3.4M in 2023, and $0.9M in 2024 represent costs incurred for planning and preparing for the workforce effects of ending commercial operation of the Pickering units. These efforts were initially aimed at managing the effects from shutting down all Pickering units. As the organizational focus shifted to the possibility of refurbishing Pickering Units 5-8, these activities became increasingly concentrated on the shutdown of Pickering Units 1 and 4. Refer to Ex. F4-3-1, Section 4.0 for further discussion.

5.23 Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account

The Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account was approved in EB-2020-0290. Effective January 1, 2021, this account records the revenue requirement impact for the prescribed facilities arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to the Pickering station EOL dates. The impacts recorded in the account are determined by applying the revised Pickering station EOL dates to recalculate the corresponding OEB-approved values comprising the nuclear liabilities' revenue requirement impact (such as ARC depreciation expense, return on rate base, and used fuel and waste management variable expenses) and the non-ARC revenue requirement impact (such as depreciation expense and return on rate base), and associated tax impacts, holding other variables constant (such as capital in-service amounts). The Application proposes to continue this methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding should a change to the Pickering Units 5-8 EOL date arise in the future.

[59] No further additions are expected in this account as of the effective date of the payment amounts order in this proceeding.

End-of-Life Change Implemented December 31, 2020

These account additions in 2023 and 2024 represent the revenue requirement impacts of extending the accounting station EOL date for Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024, effective December 31, 2020. This change and its impacts were anticipated during the course of the EB-2020-0290 proceeding but due to the timing of preparing OPG's underlying business plan, were not reflected in the forecasts underpinning the EB-2020-0290 approved payment amounts.

The derivation of the $54.6M debit entry in 2023 and $47.4M debit entry in 2024 is shown in Ex. H1-1-1, Table 18. These entries reflect the impact of changes to non-ARC depreciation and amortization expense.[60] They were calculated in the manner set out by OPG in EB-2020-0290 and reflected in the year-end 2022 balance of the account that was approved for recovery in EB-2023-0336, and are very close to the projection of these entries identified in EB-2020-0290.[61] Pickering Units 1 and 4 ended commercial operation and became fully depreciated by the end of 2024, as planned. The change in the EOL date for Pickering Units 1 and 4 is discussed in Ex. F4-1-1, Section 3.5.

As discussed in Section 5.14 above, beginning 2022, additions related to the nuclear liabilities' impact from the above EOL change are recorded in the Nuclear Liability Deferral Account in accordance with O. Reg. 53/05. The derivation of the nuclear liabilities' impact of $69.4M in 2023 and $67.9M in 2024 is included in Ex. H1-1-1, Table 18. The nuclear liabilities' impact reflects the increase in the ARO and associated ARC balances of $51.1M for the prescribed

[60] Ex. H1-1-1, Table 18, line 5, cols. (a) and (b), and EB-2023-0336, Ex. H1-1-1, Table 19, line 5 show a total change in non-ARC depreciation and amortization expense of $16.3M, rather than zero, over the 2021-2024 period in relation to these EOL date changes for Pickering Units 1 and 4. As discussed above, this amount, which is being recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, is determined by applying the revised Pickering Units 1 and 4 EOL dates to recalculate the corresponding OEB-approved values reflected in the EB-2016-0152 revenue requirement (for 2021) and EB-2020-0290 revenue requirement (for 2022-2024), holding other variables consistent with the respective revenue requirement. This approach allows for isolation of the EOL date change impact had it been known at the time of setting the original revenue requirement. Because, as a result, the impacts are calculated on a different set of underpinning forecasts (e.g., capital in-service additions) for 2021 versus 2022-2024, the net effect of the differences in non-ARC depreciation across these account entries over these four years may not be zero.

[61] OPG's responses to interrogatories in EB-2020-0290, which were completed after OPG had finalized the year-end 2020 financial information required to calculate the ARO/ARC impacts, projected comparable debit entries of $54.7M for 2023 and $47.5M for 2024 (EB-2020-0290, Ex. L-F4-01-Staff-271, Attachment 1, Table 2, line 18, cols. (b) and (c)).

facilities recorded in OPG's financial statements at year-end 2020 to reflect the changes in the Pickering Unit 1 and 4 EOL date, depreciation of existing ARC balances applied over a longer useful life, and higher used fuel variable expenses due to an increase in the per bundle cost rates reflecting a lower discount rate of 2.01% (compared to 2.94% used to forecast these costs in EB-2020-0290). The details of the year-end 2020 ARO/ARC adjustment are provided in Ex. C2-1-1, Table 4.

No additions will be required to the account related to the EOL change of Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024 as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect these impacts.

<u>End-of-Life Change Implemented December 31, 2023</u>

As discussed in Ex. F4-1-1, Section 3.5, OPG revised the accounting station EOL date for Pickering Units 5-8 from December 31, 2024 to December 31, 2070, effective December 31, 2023. This change reflected OPG's expectation of the refurbishment of these units, taking into account the Province's support for OPG's plan to proceed with the initiation phase of the PRP. Additional amounts recorded to the account in 2024 represent the revenue requirement impacts of this change, which was not anticipated in the EB-2020-0290 revenue requirements that assumed the shutdown of all Pickering units. The nuclear liabilities' impact arising from these changes is recorded in this account, rather than the Nuclear Liability Deferral Account, as the 2022 ONFA Reference Plan did not contemplate the refurbishment of Pickering Units 5-8.

The derivation of the credit entry of $2.3M in 2024 is shown in Ex. H1-1-1, Table 19. It comprises debit additions of $82.6M for revenue requirement impacts arising from changes to nuclear liabilities and credit additions of $84.9M from changes to non-ARC depreciation and amortization expense. This table also show projected account entries for 2025 and 2026, being net debit additions totaling $29.3M, provided in support of an efficient regulatory review of the balances.

The nuclear liabilities' impact primarily reflects the $474.1M increase in ARC balances for the prescribed facilities recorded in OPG's financial statements at year-end 2023 to reflect the change in the Pickering station EOL date, depreciation of existing ARC balances applied over a longer useful life, and lower used fuel and low and intermediate level variable expenses due to a decrease in the volumetric cost rates reflecting a higher discount rate. These impacts are discussed further discussed in Ex. C2-1-1, Section 5.2, and the details of the year-end 2023 ARO/ARC adjustment are provided in Ex. C2-1-1, Table 4.

The impacts recorded in the account are determined by applying the revised Pickering station EOL dates that came into effect on December 31, 2023 to recalculate the corresponding OEB-approved values reflected in the EB-2020-0290 revenue requirement, holding other variables constant, and then adjusting for the impacts from the revised station EOL date for Pickering Units 1 and 4 (discussed above) and the implementation of the 2022 ONFA Reference Plan (discussed in Section 5.14) that are captured separately in deferral accounts to avoid duplication.

In calculating the above impacts, OPG applied the same methodologies used to make entries in respect of the accounting station EOL date extension for Pickering Units 1 and 4 discussed above, as well as those previously used to make entries into the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account. The entries reflect the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities as reflected in the EB-2020-0290 revenue requirements. The Application proposes to continue to determine additions to this account on this basis as of the effective date of the payment amounts order in this proceeding for any future changes in Pickering EOL dates.

No additions will be required to the account related to the EOL change of Pickering Units 5-8 from December 31, 2024 to December 31, 2070 as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect these impacts.

No interest is recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

5.24 Clarington Corporate Campus Deferral Account

The Clarington Corporate Campus Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record, for OPG's nuclear facilities, the revenue requirement impacts of OPG's capital expenditures and operating costs for the then planned Clarington Corporate Campus. Since it was established, the account recorded a single non-capital debit entry of $7.0M in 2023, resulting in a debit balance of $7.7M as of December 31, 2024, inclusive of interest. For the reasons discussed below, no additions will be required to the account as of the effective date of the payment amounts order in this proceeding.

At the time of the EB-2020-0290 proceeding, OPG was planning for the Clarington Corporate Campus project with the goal of supporting the consolidation of OPG's workspaces through the construction of a new headquarters building in the municipality of Clarington. The project subsequently progressed through the planning phase in accordance with OPG's project governance. Prior to entering the project execution phase, OPG identified the opportunity to purchase an existing office building located at 1908 Colonel Sam Drive, Oshawa, which was economically preferred compared to building a new office building, reflecting unanticipated inflationary and supply chain pressures following the COVID-19 pandemic. As a result, OPG proceeded with the purchase of the property at 1908 Colonel Sam Drive in 2023, ultimately renovating and opening the new headquarters in August 2025, and the Clarington Corporate Campus project was closed. The debit entry of $7.0M in the account represents the project costs, attributable to OPG's regulated nuclear facilities, that were incurred until the project was terminated and were subsequently written off. Additional details can be found in Ex. D3-1-2, Sections 3.3 and 3.4.

5.25 Sale of Unprescribed Kipling Site Deferral Account

The Sale of Unprescribed Kipling Site Deferral Account was established in EB-2020-0290, effective January 1, 2022, to track 23% of the net proceeds arising from any sale of OPG's unprescribed site located at 800 Kipling Avenue (the "Kipling Site") in Toronto during the 2022-

2026 period. The account was established as part of the OEB-approved settlement proposal in EB-2020-2090, which provided in connection with any amounts tracked in the account that a party may take any position as to whether any portion of this amount should be returned to ratepayers at the time of the account's disposition. Pursuant to the OEB-approved settlement proposal in EB-2023-0336, the parties agreed that the deferral account would be disposed of, to the benefit of ratepayers, with an agreed upon balance of $12.7M as of December 31, 2022, which represented 50% of 23% of the after-tax gain recognized by OPG in 2022 associated with the sale of the Kipling Site. It was further agreed that the same treatment would apply to any after-tax gain on this sale recognized by OPG during the 2023-2026 period.[62] Since 2022, OPG recognized such an after-tax gain of $21.5M in 2023, resulting in a credit entry of $2.5M during that year. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding.

5.26 Earnings Sharing Deferral Account

The Earnings Sharing Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative 5-year period from January 1, 2022 to December 31, 2026. No entries will be recorded in this account until following the completion of the above five-year period, if applicable.

As discussed in Ex. A1-3-2, Section 4.1, OPG proposes to continue the earnings sharing mechanism for its facilities for the 2027-2031 period. Consistent with the mechanism approved in EB-2020-0290, OPG proposes to base the earnings sharing mechanism on its combined regulated nuclear and regulated hydroelectric business on an asymmetrical basis, with a 100-basis point deadband to the OEB-approved ROE rate and 50/50 sharing above the deadband, assessed over a cumulative 5-year period from 2027-2031.

[62] Decision and Order, EB-2023-0336, June 13, 2024, p.5.

To effectuate the proposed earnings sharing mechanism, OPG proposes to continue the Earnings Sharing Deferral Account. No entries will be recorded in the account with respect to the 2027-2031 period, if applicable, until following the completion of the five-year period.

5.27 Impact of IFRS Deferral Account (OPG)

The Impact for IFRS Deferral Account (OPG) was approved in EB-2020-0290, effective January 1, 2022, to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the *Securities Act* (Ontario). To date, no entries have been recorded in this account as OPG has continued to apply US GAAP to report its consolidated financial statements.

As discussed in Ex. A2-1-1, OPG's financial statements are prepared in accordance with US GAAP, as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario), which takes precedence over the continuous disclosure obligations under the *Securities Act* (Ontario). However, these requirements do not take precedence over the equivalent continuous disclosure requirements of other provincial securities regulators. This applies where OPG is also a reporting issuer by virtue of its Medium-Term Notes issued pursuant to a short form base shelf prospectus filed in these jurisdictions and subject to the requirements of *National Instrument 44-101 – Short Form Prospectus Distributions*. OPG currently receives exemptive relief from the OSC and other provincial securities regulators from the requirements of *National Instrument 52-107* ("NI 52-107") that allows OPG to file its financial statements using US GAAP instead of IFRS for continuous disclosure purposes, thereby allowing it to meet the requirements of the other provincial securities laws. Although this exemptive relief is time limited, OPG is not planning for adoption of IFRS for continuous disclosure purposes. OPG is planning to register with the U.S. Securities and Exchange Commission ("SEC") as a Foreign Private Issuer, subject to final approval by OPG's Board of Directors, to facilitate access to U.S. debt capital markets. As an SEC registered issuer, OPG would retain the ability to meet its continuous disclosure requirements in Canada by continuing to file its financial statements using US GAAP as permitted under the ongoing exemptions in NI 52-107 available for SEC registered issuers. As OPG's efforts toward SEC registration are expected to continue at least partway through the IR term, the Application proposes to continue the deferral account as of the effective date of the payment amounts order in this proceeding and as necessary to reassess this matter in the next payment amounts proceeding.

No interest is recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

5.28 Pickering B Variance Account

The Pickering B Variance Account was established in accordance with section 5.7(1) of O. Reg. 53/05, effective January 1, 2023. The account records the difference between (a) the revenues generated from the output of Pickering B (i.e., Pickering Units 5-8) during the period from January 1, 2026 to September 30, 2026, and (b) the sum of (i) any foregone revenues related to forgone output from these units arising from any Pickering B extension, (ii) the revenue requirement impacts from actual non-capital and capital costs incurred in relation to any Pickering B extension activities undertaken by OPG, and (iii) the revenue requirement impacts arising from actual non-capital and capital costs incurred since January 1, 2024 for Pickering B preservation activities before the effective date of the OEB's first payment amounts order for OPG's nuclear facilities that becomes effective on or after January 1, 2027.[63] Pickering B extension activities represent any activities OPG undertakes in furtherance of the operation of these units from January 1, 2026 to September 30, 2026, whether the activities occurred during that period or not. Pickering B preservation activities represent any activities undertaken by OPG to preserve its ability to operate Pickering Units 5-8 following the PRP, regardless of whether the project proceeds. Costs incurred for the preservation activities include but are not limited to costs payable for staffing, training, corporate support or administrative functions. Pursuant to the above provisions, no additions will be recorded to the account as of the effective date of the payment amounts order in this proceeding.

[63] O. Reg. 53/05 was initially amended on December 9, 2022 to establish this account as the Pickering B Extension Variance Account, effective January 1, 2023. That amendment did not include item (iii) in the list of amounts to be recorded in the account. O. Reg. 53/05 was subsequently amended on June 27, 2025 to add item (iii) to the list of amounts to be recorded in the account and to rename the account as the Pickering B Variance Account.

The account has a debit balance of $131.1M as of December 31, 2024, representing the impacts to date of foregone revenues related to forgone output from Pickering Units 5-8 arising from the Pickering B extension activities and the costs of such activities.[64] OPG proposes to defer the clearance of this balance to a future application, which would allow for the complete impact of operating Pickering Units 5- 8 from January 1, 2026 to September 30, 2026 and undertaking the preservation activities to be considered at the same time. In particular, once the revenues generated from operating Pickering Units 5-8 during the period from January 1, 2026-December 31, 2026 are credited to the account, the resulting balance is expected to be a net credit position.

5.29 Incremental Cloud Computing Implementation Costs Deferral Account

The Incremental Cloud Computing Implementation Costs Deferral Account was established by the OEB on a generic basis through accounting order 003-2023, effective December 1, 2023, to record incremental cloud computing implementation costs incurred and any related offsetting savings, if applicable. There were no entries recorded to the account as of December 31, 2024.

The OEB's accounting order establishing the above account indicated that a utility may propose the regulatory treatment of any material cloud computing implementation costs expected during its rate-setting term, including consideration of a new deferral account or other approaches. The Application proposes that the Incremental Cloud Computing Implementation Costs Deferral Account be terminated for OPG as of the effective date of the payment amounts order in this proceeding, with any cloud computing implementation costs reflected on a forecast basis as part of the revenue requirements requested in this Application.

[64] Ex. H1-1-1, Table 1, line 45, col. (c).

5.30 Pickering B Refurbishment Project Variance Account

The Pickering B Refurbishment Project Variance Account is established in accordance with section 5.8(1) of O. Reg. 53/05, effective January 1, 2026. The account will record the difference between: (a) the amount calculated by multiplying the actual cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term debt rate as approved by the OEB; and (b) the amount calculated by multiplying the forecast of cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term debt rate, as included in setting nuclear payment amounts. Exhibit I1-1-3, Section 5.0 presents such forecast interest amounts that the Application seeks to recover during the IR term in respect of the PRP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the PRP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 will be recorded in the account pursuant to O. Reg. 53/05.

Section 6(2)12.1(ii) of O. Reg 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 5.8(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at OPG's long-term debt rate as approved by the OEB, compounded annually.

5.31 Darlington New Nuclear Project Variance Account

The Darlington New Nuclear Project Variance Account is established in accordance with section 5.4.1(1) of O. Reg. 53/05, effective January 1, 2026.

If necessary, the account will record the difference between: (a) the amount calculated by multiplying the actual cumulative capital costs incurred by OPG in respect of the DNNP by OPG's long-term debt rate as approved by the OEB; and (b) the amount calculated by multiplying the forecast of cumulative capital costs incurred by OPG in respect of the DNNP by OPG's long-term debt rate, as included in setting nuclear payment amounts.

As set out in section 5.4.1(2)(a), the account shall not include amounts respecting capital costs incurred on or after the OEB issues an order specifying satisfaction with certain conditions set out in section 8 of the regulation. The Application expects that these requirements will be met at the end of 2025 and, thus, is not expecting that entries will be made to this account. The Application expects related entries to be made to the Darlington New Nuclear Project Variance Account re Capital Cost Amounts (established in accordance with section 12(1) of O. Reg. 53/05 and described in Section 6.3 below).

Exhibit I1-1-3, Section 4.0 presents forecast interest amounts that the Application seeks to recover during the IR term in respect of the DNNP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the DNNP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 could be eligible to be recorded in the account pursuant to O. Reg. 53/05, if necessary.

Section 6(2)11.1(ii) of O. Reg 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 5.4.1(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at OPG's long-term debt rate as approved by the OEB, compounded annually.

6.0 DNNP LP'S ACCOUNT DESCRIPTIONS

This section provides a description and sets out the purpose of DNNP LP's existing deferral and variance accounts and describes how additions to the accounts will be determined.

6.1 Darlington New Nuclear Project Variance Account re Development

The Darlington New Nuclear Project Variance Account re Development is established in accordance with section 11(1) of O. Reg. 53/05. Effective January 1, 2026[65], this account will record the differences between the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for the DNNP and such forecast amounts reflected in the payment amounts approved by the OEB. This includes but is not limited to the costs of planning, preparation and technology identification for the DNNP facilities, as well as design, development, construction, and commissioning of the DNNP facilities.[66]

The Application proposes that the above variance recorded in the account be calculated as between the revenue requirement impact of actual eligible non-capital and capital costs and firm financial commitments and such forecast amounts reflected in DNNP LP's corresponding annual revenue requirement approved by the OEB. Prior to the effective date of the payment amounts order in this proceeding, such forecast amounts are zero. Refer to Attachment 9 for the capital-related DNNP revenue requirement underpinning the IR term forecasts that would form the basis of the corresponding capital reference amounts for the DNNPVARD. As discussed in Ex. F2-2-1, the Application proposes to include the following DNNP Operational Readiness OM&A costs in the revenue requirements during the IR term, which would form the basis of the corresponding non-capital reference amounts for the DNNPVARD during the IR term: $45.9M in 2027, $46.3M in 2028, $40.0M in 2029, $40.2M in 2030, and $0.0M in 2031.[67]

The revenue requirement impact of actual capital costs for the DNNP will include the impact of any CEITCs associated with the project, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

[65] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.
[66] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 14(2)(3)), to the extent the OEB is satisfied that the costs were prudently incurred and the firm financial commitment were prudently made.
[67] Ex. F2-1-1, Table 1b, line 3.

In accordance with section 11(1) of O. Reg. 53/05, the account will also record any net revenues earned (section 11(1)b(ii)) or foregone (section 11(1)a(ii)) by DNNP LP due to deviations from the OEB-approved production forecast for the DNNP facilities due to a difference between the actual in-service date and the OEB-approved forecast in-service date of any DNNP unit. For the IR term, the forecasted DNNP Unit 1 in-service date is October 17, 2030, as discussed in Ex. D2-4-6. For this component, the account is expected to produce a credit entry should the actual in-service date be earlier than the OEB-approved forecast date and a debit entry should the actual in-service date be later than the OEB-approved forecast date.

The Application proposes that the production deviations due to a difference between the actual in-service date and the OEB-approved forecast in-service date of a DNNP unit be calculated by entering the actual in-service date into the same model used to calculate the production forecast for the DNNP facilities that underpins the payment amounts approved for DNNP LP by the OEB, holding all other variables constant (including outage plans relative to the in-service date). Deviations from the forecast would be determined as the difference between the calculated production resulting from entering the actual in-service date into such forecast model and the energy production forecast approved by the OEB. The revenue impact of the production deviation recorded in the account would be determined by multiplying the deviation from the OEB-approved forecast by the approved nuclear payment amount then in effect.

The Application further proposes that the account record, as part of net revenue, the impact of a different in-service date on the forecast nuclear fuel expense (in the form of the nuclear fuel service fees) and outage OM&A expenses. To calculate the nuclear fuel expense deviation, it is proposed that the production deviation, as determined above, be multiplied by the corresponding nuclear fuel consumption cost rate ($/MWh), as reflected in the OEB-approved revenue requirement based on the OEB-approved production forecast for the DNNP facilities. The outage OM&A expense deviation is proposed to be calculated by comparing the expenses that would have been forecast for this proceeding based on the outage timing consistent with the calculated production forecast, holding all other variables constant, and the outage OM&A expense forecast approved by the OEB.

6.2 DNNP Generator Capital Structure Variance Account

The DNNP Generator Capital Structure Variance Account ("DGCSVA") is established in accordance with section 13(1) of O. Reg. 53/05. The account records, effective January 1, 2026[68] and until the effective date of the OEB's first payment amounts order in respect of DNNP LP following the DNNP construction period, differences between: (i) the revenue requirement impacts arising from a capital structure and cost of debt reflecting the amount and cost of borrowing incurred by DNNP LP; and (ii) the amount of the revenue requirement impacts arising from the capital structure and the cost of debt reflected in the payment amounts approved by the OEB.[69] The Application's proposals with respect to DNNP LP's capital structure for the IR term are discussed in Ex. C1-1-1.

The manner in which the account entries are calculated needs to consider the interaction with the DNNPVARD, which will record the revenue requirement impact of differences between actual and forecast capital costs for the DNNP (i.e., measured as the difference between the actual and forecast rate base values) using the forecast cost of capital parameters approved by the OEB. Accordingly, for the DGCSVA, the Application proposes that the revenue requirement impacts arising from item (i) above be calculated by applying a debt component (and interest cost) equal to the actual amount of DNNP LP's debt outstanding (and interest cost) at the time to the actual rate base value (i.e., the same actual rate base value used in the DNNPVARD variance calculation), with the remaining portion of such actual rate base value representing the equity component. Item (ii) above would be calculated by applying the forecast cost of capital parameters (including percentage capital structure) approved by the OEB to the actual rate base value.

[68] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

[69] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (subsection 14(2)5), to the extent the OEB is satisfied that the costs associated with the borrowing were prudently incurred.

6.3 Darlington New Nuclear Project Variance Account re Capital Cost Amounts

The Darlington New Nuclear Project Variance Account re Capital Cost Amounts is established in accordance with section 12(1) of O. Reg. 53/05, effective January 1, 2026.[70] The account records the difference between: (a) the amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term debt rate as approved by the OEB; and (b) the amount calculated by multiplying the forecast of cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term debt rate, as included in setting nuclear payment amounts. Exhibit I1-1-3, Section 4.0 presents such forecast interest amounts that the Application seeks to recover during the IR term in respect of the DNNP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the DNNP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 will be recorded in the account pursuant to O. Reg. 53/05.

Section 14(2)4(ii) of O. Reg. 53/05 stipulates that the OEB shall ensure that DNNP LP recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 12(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's long-term term debt rate, as approved by the OEB, compounded annually.

7.0 PROPOSED NEW ACCOUNTS FOR OPG

This section sets out the details of new deferral and variance accounts proposed for OPG as of the effective date of the payment amounts order in this proceeding.

[70] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

7.1 Change of Laws Deferral Account (OPG)

OPG operates in a dynamic legal and regulatory landscape governed by a wide range of provincial and federal statutes that prescribe detailed compliance requirements, including with respect to environment, labour and safety.[71] Operating in this complex legislative framework creates considerable uncertainty in terms of forecasting the company's costs and revenues over the five-year term of this Application. As demonstrated by the historical and forecast case studies presented below, changes in laws are outside of the company's control can significantly alter compliance requirements and can have a material impact on OPG's forecasted costs and revenues. To address these risks, OPG proposes a Change of Laws Deferral Account which would record material impacts to regulated hydroelectric and nuclear costs and revenues over the IR term resulting from changes in legal and regulatory requirements, as discussed below.

7.1.1 Historical Case Study re Change in Laws

During the recent historical period, a material change in laws presented itself in the context of *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), which restricted both union and non-union provincial public sector wage and total compensation increases to 1% annually for a three-year moderation period. OPG relied on Bill 124 to forecast the compensation costs which were included in its 2022-2026 nuclear payments application (EB-2020-0290). In November 2022, after OPG's application and payments were approved by the OEB, the Ontario Superior Court overturned Bill 124, rendering the company's nuclear payment amounts deficient by approximately $188 million over the five-year rate term.[72]

In response to this material change in law, in EB-2023-0098, OPG filed an accounting order application requesting OEB approval to establish a variance account to record the nuclear revenue requirement impacts resulting from Bill 124 being overturned. The OEB denied the request, concluding that Bill 124 was a foreseeable and material risk to the OPG's forecast employee compensation costs in the 2022-2026 payment amounts application.[73] This decision was upheld by the OEB on a motion to review and vary the prior decision (EB-2023-0209), in

[71] The legislative and regulatory framework and other government requirements that govern OPG and apply to OPG's prescribed facilities are discussed in Ex. A1-6-1.
[72] Decision and Order, EB-2023-0098, June 27, 2023, pp. 7-8.
[73] Decision and Order, EB-2023-0098, June 27, 2023.

which the OEB found that it was not appropriate for OPG to recover the costs of a known risk during the multi-year rate framework, if OPG did not provide "evidence on the record about this known material risk to its compensation forecast so as to give parties an opportunity to factor that evidence into settlement discussions."[74]

7.1.2 Forecast Case Study re Change in Laws

Consistent with the OEB's findings in EB-2023-0209, aside from expected changes to the nuclear liability insurance limit under the Nuclear Liability and Compensation Act described in Ex. F4-4-1, Section 4.2, OPG notes that its 2025-2031 Business Plan and the proposed forecasts in this Application do not include any changes in laws that may occur over the IR term. As such, OPG proposes to establish a deferral account to capture material cost and revenue impacts to OPG's regulated hydroelectric and nuclear facilities arising from provincial and/or federal legislative or regulatory changes (collectively "change in law(s)"), to the extent these impacts are not already recorded in other deferral and variance accounts.

The paragraphs that follow provide an example of prospective changes in environmental laws with respect to the provincial *Endangered Species Act, 2007* ("ESA") and the federal *Species at Risk Act* ("SARA"). OPG is providing this example as a case study to illustrate the material impacts of a prospective change in law that was not included in its application forecasts. It is a foreseeable risk that these and other changes in laws may impact OPG's compliance requirements over the IR term. To the extent this happens, OPG proposes that material cost and revenue impacts arising from any changes in laws would be captured in the proposed account.

Potential Changes to Provincial and Federal Legislation

Ontario legislation concerning the American eel is evolving. The *Endangered Species Act, 2007*, where American eels were previously classified as "Endangered" under Ontario Regulation 242/08, was proposed for repeal by Bill 5 on April 17, 2025 and is expected to be eventually replaced by the *Species Conservation Act, 2025* ("SCA"). Specific requirements or changes that will be established under the new SCA are unknown. Under the former ESA,

[74] Decision and Order, EB-2023-0209, October 24, 2023, p. 9.

OPG maintains a formal agreement with the Ministry of the Environment, Conservation and Parks ("MECP") scheduled to expire in 2029, which includes an obligation to conduct research initiatives aimed at improving downstream passage for migrating eels. OPG expects to continue to operate under the existing ESA agreement until the SCA is enacted and requirements are known.[75]

In April 2024, the Fisheries and Oceans Canada ("DFO") made a recommendation to the Minister of Environment and Climate Change of Canada ("ECCC") whether to uplist American eels from "Special Concern" to "threatened" species. On December 2, 2025, the Government of Canada announced that the American Eel was not to be listed, and that the best way to conserve the species was to manage the species and its habitat under the *Fisheries Act* through "adaptive management approaches". Given the current uncertainty of the DFO's potential adaptive management requirements, OPG has not made any adjustments to its production or cost forecasts for the regulated hydroelectric facilities. Potential outcomes of DFO compliance activities could include additional capital expenditures not contemplated in the business plan, or production impacts at stations during migratory periods.

Prospective Use of the Change in Laws Deferral Account related to the American eels

As discussed above, the specific actions that OPG may be required to undertake in the IR term as a result of such regulations remain uncertain, as provincial and federal legislation continues to evolve. The potential impacts that could arise include capital and non-capital costs as well as foregone hydroelectric production.

OPG's 2025-2031 Business Plan and the forecasts in this Application do not include the costs or revenue impacts arising from potential compliance activities related to changes in provincial and/or federal regulations concerning the American eel. Thus, if OPG's regulated hydroelectric

[75] Ongoing research efforts under the existing ESA agreement are focused on the use of a "light array" to guide eels to designated locations, enabling their collection and translocation downstream of hydroelectric facilities on the St. Lawrence River. Following a pilot project to assess the success of a small-scale light array that is scheduled for 2027/2028, the MECP may require the full-scale design and deployment of the light array and eel collection system, provided it remains a priority within the incoming SCA. Cost impacts associated with such a full system are not included in OPG's forecasts for the regulated hydroelectric facilities.

facilities are faced with compliance activities related to such changes over the 2027-2031 IR term, OPG would use the proposed Change of Laws Deferral Account (OPG) to record the revenue requirement impact of costs associated with these compliance activities, as well as the impact of foregone production revenue, net of changes in GRC costs, at OPG's regulated hydroelectric facilities.

For clarity, OPG provided the American eel example noted above to illustrate the need for and impact of a prospective change in law over the 2027-2031 IR term. OPG requests, however, that the proposed account would be applicable to all changes in laws that may have a material impact on the company's regulated hydroelectric and nuclear costs or revenues over the upcoming term.

7.2 Global Hydroelectric Capital Variance Account

The Application proposes to establish the Global Hydroelectric Capital Variance Account to record the difference in revenue requirement attributed to actual total ("global") hydroelectric capital in-service amounts and the forecast CRRR amounts underpinning the capital factor calculation presented in Ex. I1-2-1, Table 2, as assessed after the 2028-2031 period. The proposed account would be asymmetric in that an amount could be credited to ratepayers in the event the CRRR determined based on actual capital in-service additions over the period is less than the CRRR underpinning the capital factor calculation. In the event the CRRR based on actual capital in-service additions is greater than the CRRR underpinning the C-factor, there would be no recovery from ratepayers through this account. Further details on the proposed operation of the account are discussed in Ex. A1-3-2, Section 2.3.5.

7.3 Clean Electricity ITC Variance Account (OPG)

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects, which is proposed to be available to certain entities including OPG. At the time of filing the Application, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan or the proposed revenue requirements in this Application. In accordance with US GAAP, OPG will account for such credits, once received, as a reduction in the capital costs of the underlying eligible projects. The revenue requirement savings from the CEITCs will therefore be realized through a reduction in the capital related revenue requirement once these assets are in service.

The Application proposes to establish the Clean Electricity ITC Variance Account (OPG) to record the revenue requirement differences as between the actual CEITCs received for eligible projects and those attributed to corresponding forecast CEITCs reflected in the OEB-approved payment amounts, if any, for OPG's regulated hydroelectric and nuclear facilities. This account would record such differences only to the extent they are not captured by an existing account, such as the NDVA or the CRVA.

For OPG's nuclear facilities, the variances will be recorded relative to the corresponding forecast amounts included in OPG's annual nuclear revenue requirements approved by the OEB. For the regulated hydroelectric facilities, the Application proposes that any variances be determined with reference to the corresponding 2027-2031 annual forecast amounts. This approach reflects the proposed hydroelectric rate-setting framework for the 2027-2031 term, whereby the forecast CRRR underpins the proposed C-factor. The hydroelectric rate-setting proposal is discussed in Ex. A1-3-2, Section 2.0, with the potential resulting interaction between the Clean Electricity ITC Variance Account (OPG) and the Global Hydroelectric Capital Variance Account addressed in Ex. A1-3-2, Section 2.3.5.[76]

Further details on the CEITCs, including the details of their capital related revenue requirement impact, are discussed in Ex. F4-2-1, Section 3.5.

7.4 Payment Amount Shaping Deferral Account

The Application proposes to establish the Payment Amount Shaping Deferral Account to record, during the IR term, the difference between: (i) OPG's total annual nuclear revenue requirement approved by the OEB; and (ii) the portion of that revenue requirement in (i) that is used in connection with setting the nuclear payment amounts in each year ("the deferral

[76] Any additions to the Clean Electricity ITC Variance Account (OPG) will be calculated without duplication with other accounts that may be impacted.

amount”). An annual deferral amount as determined by the OEB would be recorded in the account from January 1, 2027 until December 31, 2031. As described in Ex. I1-3-2, this account is proposed in conjunction with OPG’s payment amount shaping proposal to help manage the 2027 ratepayer impact while balancing OPG’s financing needs over the period.

OPG is proposing offsetting debit and credit entries to the Payment Amount Shaping Deferral Account during the 2027-2031 period such that a nil balance remains in the account at December 31, 2031, before interest.

As discussed at Ex. I1-3-2, OPG proposes to set the annual deferral amounts as follows for the IR term, to be recorded on a monthly straight-line basis: $500.0M in 2027, -$500.0M in 2028, $0.0M in 2029, $0.0M in 2030, and $0.0 in 2031.

Consistent with the treatment of the Rate Smoothing Deferral Account, OPG proposes to record interest on the balance of the account at a long-term debt rate reflecting OPG’s cost of long-term borrowing, as approved by the OEB, compounded annually.

7.5 DNNP Nuclear Liability Deferral Account

OPG will be responsible for the nuclear waste management and decommissioning obligations arising from the DNNP facilities. Pursuant to section 6(2)10.1 of O. Reg. 53/05, the Application proposes to establish the DNNP Nuclear Liability Deferral Account to record the difference between: (i) the costs of OPG’s nuclear waste management and decommissioning liabilities (“nuclear liabilities costs”) with respect to the DNNP facilities, as reflected in OPG’s audited annual financial statements approved by OPG’s Board of Directors; and (ii) the nuclear liabilities costs with respect to the DNNP facilities reflected in OPG’s nuclear revenue requirement approved by the OEB.

Effective January 1, 2026, amendments to O. Reg. 53/05 provide for the recovery of nuclear liability costs. In section 0.1 of O. Reg. 53/05 defines “nuclear decommissioning liability” as follows:

> "nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for,
>
> (a) decommissioning the nuclear facilities, the Bruce Nuclear Generating Stations and, on and after the DNNP transition date, the DNNP Nuclear Generating Station, and
>
> (b) the management of Ontario Power Generation Inc.'s nuclear waste and used fuel.

Section 6(2)10.1 of O. Reg. 53/05 states:

> The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs in relation to its nuclear decommissioning liability with respect to the Bruce Nuclear Generating Stations and the DNNP Nuclear Generating Station as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., to the extent that those costs are not otherwise recovered under this subsection.

The above provisions have the effect of requiring OPG to recover its nuclear liabilities costs with respect to the DNNP facilities as they are reflected in OPG's audited financial statements. This will result in OPG recovering these costs using the same methodology that the OEB has approved for the Bruce facilities, and this would be the methodology for recording entries in this account. This methodology is described in Ex. C2-1-1, Section 4.2.[77]

As discussed in Ex. C2-1-1, Section 8.0, the comprehensive cost estimates for these future nuclear liabilities have not yet been recorded in OPG's financial statements and the Application does not reflect any corresponding amounts in the proposed IR term nuclear revenue requirements. At such time as the costs of the nuclear liabilities with respect to the DNNP

[77] Amendments made to section 6(2)10.1 of O. Reg. 53/05 requiring the OEB to ensure that OPG recovers all costs it incurs in relation to its nuclear liabilities with respect to the Bruce facilities as reflected in the audited financial statements approved by OPG's Board of Directors, to the extent that those costs are not otherwise recovered under section 6(2) of the regulation, have the effect of confirming the current recovery methodology for OPG's nuclear liabilities' costs for the Bruce facilities.

facilities are recognized in OPG's financial statements during the IR term, they would be recorded in the account as reflected in those financial statements.

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of similar accounts for OPG.

8.0 PROPOSED NEW ACCOUNTS FOR DNNP LP

This section sets out the details of new deferral and variance accounts proposed for DNNP LP as of the effective date of the payment amounts order in this proceeding. Given the similarity of operations between DNNP LP and OPG as nuclear generators, the common cost structure between the two entities by virtue of OPG's role as project manager and operator of the DNNP facilities and the blended nuclear payment amount, the requested accounts mirror the applicable existing and proposed new accounts for OPG.

8.1 Pension and OPEB Cost Variance Account (DNNP)

The Application proposes to establish the Pension and OPEB Cost Variance Account (DNNP) to record the differences between: (i) the pension and OPEB costs reflected in the DNNP LP's revenue requirement approved by the OEB; and (ii) DNNP LP's actual pension and OPEB costs for the DNNP facilities.[78]

As discussed in Ex. F4-3-2, DNNP LP's pension and OPEB costs represent the portion of OPG's pension and OPEB accrual costs attributed to the DNNP facilities and to be charged to DNNP LP under the respective agreements with OPG. Following the transfer of the DNNP assets to DNNP LP, these costs would not be eligible for the Pension and OPEB Cost Variance Account (OPG) and are proposed to be captured in this new deferral account. Actual pension and OPEB costs used in the calculation of the account entries would be calculated on an

[78] Unlike OPG's prescribed facilities, the DNNP facilities will not experience a difference between pension and OPEB accrual costs and pension and OPEB cash amounts, due to the fact that once charged to DNNP LP, any pension and OPEB costs become cash expenditures to DNNP LP (i.e., payable to OPG). Accordingly, there is no such timing difference expected in the regulatory tax calculations for DNNP LP (Ex. F4-2-1) and no regulatory tax impact to be recorded in the proposed Pension and OPEB Cost Variance Account (DNNP). Also for this reason, there will be no amounts to record in the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account for DNNP LP.

accrual basis using the same accounting standards as those used to derive the reference amount. The same methodology for recording entries in the account would be used as for the Pension and OPEB Cost Variance Account (OPG).

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of the Pension and OPEB Cost Variance Account (OPG).

8.2 Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)

The Application proposes to establish the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP) to record the difference between the amounts approved for recovery or repayment in nuclear deferral and variance accounts and the actual amounts recovered or repaid based on the actual nuclear production and approved riders. Pursuant to the OEB's orders, the account would also capture the transfer of balances remaining in other DNNP LP accounts as they expire from time to time. The same methodology for recording entries in the account would be used as for the Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG).

8.3 SR&ED ITC Variance Account (DNNP)

The Application proposes to establish the SR&ED ITC Variance Account (DNNP) to record the difference between actual SR&ED ITCs attributed to the DNNP facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the DNNP LP's revenue requirement approved by the OEB, including the tax on the difference. The same methodology for recording entries in the account would be used as for the SR&ED ITC Variance Account (OPG). The reasons for maintaining such accounts for OPG's regulated facilities and the DNNP facilities are discussed in Ex. F4-2-1, Section 3.5.

8.4 Income and Other Taxes Variance Account (DNNP)

The Application proposes to establish the Income and Other Taxes Variance Account (DNNP) to record the financial impact on the DNNP LP's revenue requirement of the following:

- Any differences in income or capital taxes, or payments in lieu thereof, that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada)

- and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario)), or other equivalent provincial legislation, as modified by the regulations under the *Electricity Act, 1998*, as applicable, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for DNNP LP or the DNNP facilities under the *Assessment Act, 1990*;
- Any differences in income or capital taxes, or payments in lieu thereof, that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and
- Any differences in income or capital taxes, or payments in lieu thereof, that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to DNNP LP or the DNNP facilities or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

The same methodology for recording entries in the account would be used as for the Income and Other Taxes Variance Account (OPG). Entries in the account would be recorded relative to the income tax provision and the underlying inputs reflected in the approved revenue requirement for DNNP LP for the corresponding year. The account would not record the impact of any of the above in relation to SR&ED ITCs and the income taxes payable thereon. The forecast annual income tax provision for the DNNP facilities for the IR term is detailed in Ex. F4-2-1, Table 3g.[79]

The account is not proposed to include the revenue requirement impact of the CEITCs that may be available to DNNP LP and its partners. Instead, the Application proposes to record any such revenue requirement impacts in applicable accounts as follows: the DNNPVARD for the DNNP and the proposed new Clean Electricity ITC Variance Account (DNNP) for the remaining eligible

[79] Any additions to the Income and Other Taxes Variance Account (DNNP) will be calculated without duplication with other accounts that may be impacted such as the DNNPVARD.

expenditures (Section 8.6). Clean Electricity Investment Tax Credits are discussed in Ex. F4-2-1, Section 3.5.

8.5 Impact for IFRS Deferral Account (DNNP)

The Application proposes to establish the Impact for IFRS Deferral Account (DNNP) to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that DNNP LP adopts IFRS for financial reporting purposes.

As discussed in Section 5.27, OPG is proposing to continue the Impact for IFRS Deferral Account (OPG) as it moves forward with its efforts toward SEC registration, which would allow OPG to retain an ongoing ability to meet continuous disclosure requirements in Canada by continuing to file its financial statements using US GAAP. Should OPG's account be continued, the proposed equivalent account for DNNP LP would facilitate ongoing alignment of the regulatory accounting framework between the two entities.

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of the Impact for IFRS Deferral Account (OPG).

8.6 Clean Electricity ITC Variance Account (DNNP)

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects, which is proposed to be available to certain entities including OPG. At the time of filing the Application, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan or this Application. In accordance with US GAAP, such credits will be accounted as a reduction in the capital costs of the underlying eligible projects. The revenue requirement savings from the CEITCs will therefore be realized through a reduction in the capital related revenue requirement once the assets are in service.

The Application proposes to establish the Clean Electricity ITC Variance Account (DNNP) to record the revenue requirement differences as between the actual CEITCs received for eligible projects and those attributed to corresponding forecast CEITCs reflected in the OEB-approved payment amounts, if any, for the DNNP facilities. This account would record such differences only to the extent they are not captured by an existing account, such as the DNNPVARD. The variances will be recorded relative to the corresponding forecast amounts included in the DNNP LP's annual nuclear revenue requirements approved by the OEB.

Further details on the CEITCs, including their details of the capital related revenue requirement impact, are discussed in Ex. F4-2-1, Section 3.5.

8.7 Impact of Change in Tax Status Variance Account (DNNP)

As discussed in Ex. F4-2-1, regulatory income taxes that form part of the proposed revenue requirement for DNNP LP are determined by applying the statutory tax rates to the portion of the regulatory taxable income or loss attributable to the taxable partners of the partnership. Accordingly, any regulatory taxable income or loss attributable to the tax-exempt partners of DNNP LP result in no associated regulatory income taxes to be recovered in the revenue requirement.

As a result of the above, any changes to the tax status (i.e., taxable or tax-exempt) of current and future partners of DNNP LP can impact the partnership's revenue requirement. The Application proposes to establish the Impact of Change in Tax Status Variance Account to record the impact on the forecast regulatory income taxes reflected in revenue requirement approved by the OEB from any changes to the tax status of DNNP LP's partners.[80] For further discussion on the determination of regulatory income taxes for DNNP LP, refer to Ex. F4-2-1, Section 3.1.

8.8 Change of Laws Deferral Account (DNNP)

Changes in laws are outside of DNNP LP's control and can significantly alter compliance requirements and can have a material impact on DNNP LP's forecasted costs and revenues.

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[80] Any additions to the Impact of Change in Tax Status Variance Account (DNNP) will be calculated without duplication with other accounts that may be impacted such as the Income & Other Taxes Variance Account (DNNP) and the Clean Electricity ITC Variance Account (DNNP)..

To address these risks, and for the same reasons that an equivalent account is proposed for OPG in Section 7.1, the Application proposes to establish the Change of Laws Deferral Account (DNNP) which would record material impacts to costs and revenues of DNNP LP over the IR term resulting from changes in legal and regulatory requirements to the extent these impacts are not already recorded in other deferral and variance accounts.

9.0 INTEREST

OPG proposes to record interest on all existing and new deferral and variance accounts, unless specified otherwise in the account descriptions above. For these accounts, OPG proposes to apply interest to the monthly opening balances of these accounts at the interest rate set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts, unless specified otherwise in the account descriptions above.

The above approach was used to apply interest to deferral and variance account balances in determining the December 31, 2024 audited balances in the accounts pursuant to the OEB's decisions and orders, as applicable.

LIST OF ATTACHMENTS

Building a better
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INDEPENDENT AUDITOR'S REPORT

To the management of
Ontario Power Generation Inc.

Opinion

We have audited the schedule of regulatory balances of Ontario Power Generation Inc. as at December 31, 2024 (the "Schedule").

In our opinion, the accompanying schedule, which presents the balances of the deferral and variance accounts authorized for Ontario Power Generation Inc. by the decisions and orders of the Ontario Energy Board, is prepared, in all material respects in accordance with the basis of accounting as described in Note 1 to the Schedule.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the Schedule* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the Schedule in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of matter – Basis of accounting and restriction on use

We draw attention to Note 1 of the Schedule, which describes the basis of accounting. The Schedule is prepared to assist the Company in filing with the Ontario Energy Board as part of the regulatory process. As a result, the Schedule may not be suitable for another purpose. Our report is intended solely for the information and use of the Company and for filing with the Ontario Energy Board as part of the regulatory process. Our opinion is not modified in respect of this matter.

Responsibilities of management for the Schedule

Management is responsible for the preparation and fair presentation of the Schedule in accordance with the basis of accounting as described in Note 1 of the Schedule; this includes determining that the basis of accounting is an acceptable basis for the preparation of the Schedule in the circumstances, and for such internal control as management determines is necessary to enable the preparation of the Schedule that are free from material misstatement, whether due to fraud or error.

In preparing the Schedule, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern, and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the Schedule

Our objectives are to obtain reasonable assurance about whether the Schedule as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can

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arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the Schedule.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Schedule, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the Schedule or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the Schedule, including the disclosures, and whether the Schedule represents the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence to express an opinion on the Schedule. We are responsible for the direction, supervision and performance of the audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst + Young LLP

Toronto, Canada
November 28th, 2025

Chartered Professional Accountants
Licensed Public Accountants

SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2024

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. (OPG or the Company) receives regulated prices for electricity generated from most of the Company's hydroelectric generating facilities and all of the nuclear generating facilities that the Company operates. OPG's regulated prices for the generation from these facilities are determined by the Ontario Energy Board (OEB).

The OEB's decisions and orders have authorized OPG to establish certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The balances in these accounts are calculated in accordance with the OEB's decisions and orders and *Ontario Regulation 53/05*. In accordance with United States generally accepted accounting principles ("US GAAP"), OPG's consolidated financial statements recognize regulatory assets and regulatory liabilities for balances in the variance and deferral accounts.

Through its August 2021 oral decision approving a settlement between OPG and intervenors on OPG's application for new regulated prices under case number EB-2020-0290 and its November 2021 written decision on the same, the OEB approved balances as at December 31, 2019 in all of the Company's variance and deferral accounts for which clearance was sought, as adjusted by the OEB's decisions, and less amounts previously approved for recovery or repayment in these accounts under case numbers EB-2016-0152 and EB-2018-0243. The OEB's 2021 decision and related settlement agreement also deferred recovery of a portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account to a future proceeding. Certain account balances were excluded from OPG's application. To effect the recovery and repayment of the balances approved in the EB-2020-0290 proceeding, the OEB established rate riders for OPG's regulated generation for the period from January 1, 2022 to December 31, 2026.

Through its June 2024 decision approving a settlement between OPG and intervenors on OPG's application for disposition of variance and deferral account balances and other matters under case number EB-2023-0336, the OEB approved the balances as at December 31, 2022 in all such accounts brought forward for disposition in that proceeding, as adjusted by the results of the approved settlement, and less amounts previously approved for recovery or repayment under case numbers EB-2020-0290 and EB-2018-0243. This approval included the portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account deferred as a result of the EB-2020-0290 proceeding. Certain account balances were excluded from OPG's application. To effect the recovery and repayment of the balances approved in the EB-2023-0336 proceeding, the OEB established incremental rate riders for OPG's regulated generation for the period from July 1, 2024 to December 31, 2026.

For the period from January 1, 2023 to December 31, 2024, OPG recognized additions to the variance and deferral accounts and amortized the balances in the accounts as authorized by the OEB in the EB-2020-0290 Payment Amounts Order and the EB-2023-0336 Decision and Order. Where applicable, OPG also recognized additions to variance and deferral account during this period in accordance with the requirements of *Ontario Regulation 53/05*. Where authorized by the OEB, OPG recorded interest on the unamortized balances in the applicable variance and deferral accounts at the OEB-prescribed rate ranging from 4.40 percent per annum to 5.49 percent per annum during the period from January 1, 2023 to December 31, 2024.

As at December 31, 2024, the balances to be recovered from (refunded to) ratepayers in the variance and deferral accounts authorized for OPG were as follows:

(millions of dollars)	**2024**
Regulated Hydroelectric	
Hydroelectric Surplus Baseload Generation Variance Account	**306**
Capacity Refurbishment Variance Account – Hydroelectric	**162**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Post-2017 Additions – EB-2020-0290 Approved	**18**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Registered Pension Plan (RPP) – EB-2018-0243 Approved	**16**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Post-2019 Additions	**(8)**
Pension & OPEB Cash Payment Variance Account – Hydroelectric	**(76)**
Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account – Hydroelectric	**(9)**
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	**17**
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	**9**
Income and Other Taxes Variance Account – Hydroelectric	**(17)**
Ancillary Services Net Revenue Variance Account – Hydroelectric	**(22)**
Hydroelectric Water Conditions Variance Account	**(173)**
Gross Revenue Charge Variance Account	**-**
Impact for IFRS Deferral Account – Hydroelectric	**-**
Hydroelectric Incentive Mechanism Variance Account	**-**
Incremental Cloud Computing Implementation Costs Deferral Account – Hydroelectric	**-**
Total – Regulated Hydroelectric	**223**
Nuclear	
Rate Smoothing Deferral Account	**677**
Nuclear Liability Deferral Account	**527**
Capacity Refurbishment Variance Account – Nuclear – Darlington Refurbishment Program (DRP) – Excluding Heavy Water Storage and Drum Handling Facility Project (D2O Storage Project)	**170**
Capacity Refurbishment Variance Account – Nuclear – Non-DRP	**174**
Capacity Refurbishment Variance Account – Nuclear – Accelerated Investment Incentive CCA-DRP – EB-2020-0290/EB-2023-0336 Approved	**(17)**
Capacity Refurbishment Variance Account – Nuclear – D2O Storage Project – EB-2023-0336 Approved	**70**
Pension and OPEB Cost Variance Account – Nuclear – Post 2021 Additions	**(411)**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – RPP – EB-2018-0243 Approved	**107**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – Post-2017 Additions – EB-2020-0290 Approved	**111**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – Post-2019 Additions – EB-2023-0336 Approved	**132**
Pension & OPEB Cash Payment Variance Account – Nuclear – EB-2020-0290/EB-2023-0336 Approved	**(245)**
Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account – Nuclear	**(42)**
Pickering B Variance Account	**131**
Bruce Lease Net Revenues Variance Account	**(60)**
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**(61)**
Income and Other Taxes Variance Account – Nuclear	**(10)**
Nuclear Development Variance Account – Darlington New Nuclear Project (DNNP)	**62**
Nuclear Development Variance Account – Non-DNNP	**23**
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account – December 31, 2020	**66**
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account – December 31, 2023	**(2)**
Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account – EB-2020-0290/EB-2023-0336 Approved	**85**

Ancillary Services Net Revenue Variance Account – Nuclear	**(14)**
SR&ED ITC Variance Account	**(25)**
Fitness for Duty Deferral Account	**3**
Pickering Closure Costs Deferral Account	**8**
Clarington Corporate Campus Deferral Account	**8**
Impact for IFRS Deferral Account – Nuclear	**-**
Incremental Cloud Computing Implementation Costs Deferral Account – Nuclear	**-**
Total – Nuclear	**1,467**
Earnings Sharing Deferral Account	**-**
Sale of Unprescribed Kipling Site Deferral Account	**(13)**
Grand Total	**1,677**

This schedule of regulatory balances has been prepared solely for the use of OPG’s management and for filing with the OEB, and is considered by OPG’s management to be a fair and reasonable representation of the balances in the authorized variance and deferral accounts as at December 31, 2024. These balances have been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.

Aida Cipolla
Chief Financial Officer and Chief Administrative Officer
November 28, 2025

See accompanying note to the schedule

NOTE TO THE SCHEDULE OF REGULATORY BALANCES AS AT DECEMBER 31, 2024

1. BASIS OF ACCOUNTING

The schedule of regulatory balances presents the balances as at December 31, 2024 in all variance and deferral accounts authorized for OPG, with the exception of the Pension and OPEB Forecast Accrual Versus Actual Cash Differential Variance Account – Primary and Contra sub-accounts which are offsetting by definition. The balances presented represent the regulatory assets and regulatory liabilities for these accounts recorded by OPG in accordance with US GAAP for the purposes of its consolidated financial statements, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers and to include the full amount of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017. The Pension and OPEB Forecast Accrual Versus Actual Cash Differential Variance Account – Primary and Contra sub-accounts have a net zero balance at all times pursuant to the Report of the Ontario Energy Board under case number EB-2015-0040. All dollar amounts are presented in Canadian dollars.

For the purposes of its consolidated financial statements prepared in accordance with US GAAP, as required by FASB Accounting Standards Codification Topic 980, *Regulated Operations*, OPG limits the portion of cost of capital additions recognized as a regulatory asset to the amount calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances. The amortization expense related to the regulatory assets for variance and deferral accounts that include cost of capital additions are correspondingly limited in OPG’s consolidated financial statements to amounts calculated using the average rate of capitalized interest applied to OPG’s construction and development in progress balances.

In the EB-2016-0152 Payment Amounts Order issued on March 23, 2018, the OEB stipulated that OPG will be entitled to future recovery of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 to the extent that OPG’s total capital in-service additions for the regulated hydroelectric facilities over the 2017-2021 period exceed the funding for capital expenditures for these facilities implicit in the hydroelectric payment amounts over that period, as calculated pursuant to the EB-2016-0152 Payment Amounts Order. In the EB-2020-0290 Payment Amounts Order issued on January 27, 2022, the OEB stipulated that OPG will be entitled to future recovery of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective January 1, 2022 to the extent that OPG’s total capital in-service additions for the regulated hydroelectric facilities over the 2022-2026 period exceed the funding for capital expenditures for these facilities implicit in the hydroelectric payment amounts over that period, as calculated pursuant to the EB-2020-0290 Payment Amounts Order. In accordance with US GAAP, OPG's consolidated financial statements recognize a regulatory asset for additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 when OPG assesses there is sufficient assurance that these amounts will be recoverable in the future based on the above condition.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that incurred costs in respect of its regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in the Company’s consolidated financial statements. When OPG is required to refund amounts in respect of its regulated facilities to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability in its consolidated financial statements. The measurement of regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB’s decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB’s decisions are reviewed as part of the OEB’s regulatory process.

OPG’s most recent annual consolidated financial statements filed with the Ontario Securities Commission are as at and for the year ended December 31, 2024. OPG’s most recent interim consolidated financial statements filed with the Ontario Securities Commission are as at and for the nine months ended September 30, 2025.

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Attachment 5
Regulated Hydroelectric CRVA Projects - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the regulated hydroelectric CRVA projects capital component that are reflected in the proposed revenue requirements for OPG's regulated hydroelectric facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Regulated Hydroelectric CRVA Projects Rate Base	1	794.3	1,230.1	2,237.3	2,800.7	3,262.6
2	Weighted Average Cost of Capital	2	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**55.1**	**86.5**	**158.6**	**199.3**	**232.5**
	Depreciation						
4	Regulated Hydroelectric CRVA Projects	1	13.5	21.0	38.3	48.4	57.0
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		37.6	58.3	106.0	132.7	154.6
6	Depreciation (line 4)		13.5	21.0	38.3	48.4	57.0
7	CCA (Ex. F4-2-1, Table 3c, Note 3)		(277.4)	(212.0)	(220.2)	(231.0)	(246.4)
8	**Net Decrease in Regulatory Taxable Income**		**(226.3)**	**(132.7)**	**(76.0)**	**(49.9)**	**(34.8)**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(75.4)**	**(44.2)**	**(25.3)**	**(16.6)**	**(11.6)**
11	**Total Regulated Hydroelectric CRVA Projects Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(6.8)**	**63.3**	**171.6**	**231.1**	**277.9**

Notes: Refer to Attachment 5a.

Attachment 5a
Notes to Table 5
Regulated Hydroelectric - CRVA Projects Revenue Requirement (Capital Component) ($M)

Notes:

1 The amounts in line 1 are determined as follows:

Line No.		2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	Gross Plant Opening Balance	-	211.6	512.9	1,020.5	1,820.5	2,585.8	3,263.8
1b	In-Service Additions*	211.6	301.3	507.6	800.0	765.3	678.0	311.9
1c	Gross Plant Closing Balance (line 1a + line 1b)	211.6	512.9	1,020.5	1,820.5	2,585.8	3,263.8	3,575.7
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2**	82.6	362.2	808.4	1,261.5	2,298.4	2,905.1	3,419.8
1e	Accumulated Depreciation Opening Balance	-	1.4	7.4	20.9	41.9	80.2	128.6
1f	Depreciation	1.4	6.0	13.5	21.0	38.3	48.4	57.0
1g	Accumulated Depreciation Closing Balance (line 1e + line 1f)	1.4	7.4	20.9	41.9	80.2	128.6	185.6
1h	Accumulated Depreciation Rate Base Amount (line 1d + line 1g)/2	0.7	4.4	14.2	31.4	61.1	104.4	157.1
1i	Net Plant Rate Base Amount (line 1d - line 1h)	81.9	357.8	794.3	1,230.1	2,237.3	2,800.7	3,262.6

* Proposed reference amounts for the IR term reflects revenue requirement impacts from expected in-service amounts related to eligible projects beginning January 1, 2025 - shown above in line 1b - since such amounts in the bridge years will form part of the forecast underpinning the proposed 2027-2031 revenue requirement for the account. Cascading variances in the IR term from revenue requirement differences between the forecast and actual in-service additions during the bridge years would be recorded in the account.

CRVA-eligible projects with expected in-service amounts in the 2025-2031 period which form part of the proposed 2027-2031 capital related revenue requirement are identified in Ex. D1-1-2, Tables 1, 2a, 2b, 5a and 5b.

** For years including impacts from in-service additions exceeding $50.0M, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

2 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 6
Pickering Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Pickering Refurbishment Program capital component that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	PRP Rate Base (Ex. B3-1-1, Table 2, lines 6 and 18)		166.4	172.8	168.7	164.7	6,139.3
2	Weighted Average Cost of Capital	1	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**11.6**	**12.2**	**12.0**	**11.7**	**437.5**
	Depreciation						
4	PRP (Ex. F4-1-1, Table 2, line 6)		3.8	4.1	4.1	4.1	156.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		7.9	8.2	8.0	7.8	290.8
6	Depreciation (line 4)		3.8	4.1	4.1	4.1	156.7
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(275.9)	(572.1)	(953.7)	(1,169.4)	(1,241.9)
8	**Net Decrease in Regulatory Taxable Income**		**(264.2)**	**(559.8)**	**(941.7)**	**(1,157.5)**	**(794.3)**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(88.1)**	**(186.6)**	**(313.9)**	**(385.8)**	**(264.8)**
11	**Total PRP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(72.7)**	**(170.4)**	**(297.9)**	**(370.1)**	**329.5**

Notes:
1 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 7

Darlington Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Darlington Refurbishment Program capital component, excluding D2O Storage, that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DRP Rate Base, excluding D2O Storage (Ex. B3-1-1, Table 2, lines 2 and 14)		9,906.7	9,508.2	9,109.8	8,711.6	8,313.6
2	Weighted Average Cost of Capital	1	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**687.8**	**668.7**	**645.8**	**619.9**	**592.5**
	Depreciation						
4	DRP, excluding D2O Storage (Ex. F4-1-1, Table 2, line 2)		398.5	398.5	398.4	398.0	398.0
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		469.3	450.4	431.5	412.7	393.8
6	Depreciation (line 4)		398.5	398.5	398.4	398.0	398.0
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(484.4)	(445.8)	(410.4)	(377.8)	(348.0)
8	**Net Increase in Regulatory Taxable Income**		**383.4**	**403.1**	**419.6**	**432.8**	**443.8**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**127.8**	**134.4**	**139.9**	**144.3**	**147.9**
11	**Total DRP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**1,214.1**	**1,201.5**	**1,184.0**	**1,162.2**	**1,138.4**

Notes:

1 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Attachment 8
Non-DRP/Non-PRP Nuclear CRVA Projects - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Non-DRP/Non-PRP Nuclear CRVA Projects capital component that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Non-DRP/Non-PRP Nuclear CRVA Projects Rate Base	1	220.1	677.7	785.0	1,426.6	2,287.2
2	Weighted Average Cost of Capital	2	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**15.3**	**47.7**	**55.7**	**101.5**	**163.0**
	Depreciation						
4	Non-DRP/Non-PRP Nuclear CRVA Projects	1	8.6	27.8	33.5	63.1	105.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		10.4	32.1	37.2	67.6	108.3
6	Depreciation (line 4)		8.6	27.8	33.5	63.1	105.7
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(60.5)	(89.8)	(135.2)	(164.9)	(200.2)
8	**Net Increase (Decrease) in Regulatory Taxable Income**		**(41.4)**	**(29.9)**	**(64.5)**	**(34.2)**	**13.8**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(13.8)**	**(10.0)**	**(21.5)**	**(11.4)**	**4.6**
11	**Total Non-DRP/Non-PRP Nuclear CRVA Projects Capital Revenue Requirement** (line 3 + line 4 + 10)		**10.1**	**65.5**	**67.7**	**153.2**	**273.3**

Notes: Refer to Attachment 8a.

Attachment 8a
Notes to Table 8
Non-DRP/Non-PRP Nuclear CRVA Projects - Revenue Requirement (Capital Component) ($M)

Notes:
1 The amounts in line 1 are determined as follows:

Line No.		2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	Gross Plant Opening Balance	-	108.0	209.8	399.1	785.8	1,426.2	2,211.9
1b	In-Service Additions*	108.0	101.8	189.3	386.7	640.4	785.8	536.9
1c	Gross Plant Closing Balance (line 1a + line 1b)	108.0	209.8	399.1	785.8	1,426.2	2,211.9	2,748.9
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2**	76.3	131.8	231.7	707.6	845.6	1,535.5	2,480.4
1e	Accumulated Depreciation Opening Balance	-	2.5	7.3	15.9	43.7	77.3	140.4
1f	Depreciation	2.5	4.8	8.6	27.8	33.5	63.1	105.7
1g	Accumulated Depreciation Closing Balance (line 1e + line 1f)	2.5	7.3	15.9	43.7	77.3	140.4	246.0
1h	Accumulated Depreciation Rate Base Amount (line 1e + line 1g)/2	1.3	4.9	11.6	29.8	60.5	108.8	193.2
1i	Net Plant Rate Base Amount (line 1d - line 1h)	75.1	126.9	220.1	677.7	785.0	1,426.6	2,287.2

* Proposed reference amounts for the IR term reflects revenue requirement impacts from expected in-service amounts related to eligible projects beginning January 1, 2025 - shown above in line 1b - since such amounts in the bridge years will form part of the forecast underpinning the proposed 2027-2031 revenue requirement for the account. Cascading variances in the IR term from revenue requirement differences between the forecast and actual in-service additions during the bridge years would be recorded in the account.

CRVA-eligible projects with expected in-service amounts in the 2025-2031 period which form part of the proposed 2027-2031 capital related revenue requirement for the CRVA are identified in Ex. D2-1-3, Tables 1a-1c, 2a-2g, and 5a-5d.

** All years include impacts from in-service additions exceeding $50.0M, hence the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

2 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 9
Darlington New Nuclear Program Revenue Requirement ($M)

Shown below is the derivation of amounts for the Darlington New Nuclear Program that are reflected in the proposed revenue requirements for DNNP facilities in this proceeding and proposed to form the corresponding reference amounts for the Darlington New Nuclear Project Variance Account re Development.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DNNP Rate Base (Ex. B3-1-1, Table 2, lines 12 and 24)		0.0	0.0	0.0	1,360.5	6,507.4
2	Weighted Average Cost of Capital	1	0.00%	0.00%	0.00%	9.11%	9.11%
3	**Cost of Capital** (line 1 x line 2)		**0.0**	**0.0**	**0.0**	**123.9**	**592.8**
	Depreciation						
4	DNNP (Ex. F4-1-1, Table 2, line 12)		0.0	0.0	0.0	22.6	109.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 100% x 9.11%)		0.0	0.0	0.0	123.9	592.8
6	Depreciation (line 4)		0.0	0.0	0.0	22.6	109.7
7	CCA (Ex. F4-2-1, Table 3g, line 8)		(195.5)	(311.1)	(345.0)	(365.6)	(377.3)
8	**Net Increase (Decrease) in Regulatory Taxable Income**		**(195.5)**	**(311.1)**	**(345.0)**	**(219.0)**	**325.3**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(65.2)**	**(103.7)**	**(115.0)**	**(73.0)**	**108.4**
11	**Total DNNP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(65.2)**	**(103.7)**	**(115.0)**	**73.6**	**811.0**

Notes:
1 Col. (d) is calculated as: Ex. C1-1-1, Table 14, line 4, col. (b) x col. (c)
Col. (e) is calculated as: Ex. C1-1-1, Table 13, line 4, col. (b) x col. (c)

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2022, 2023 and 2024 ($M)

Line No.	Account	Note	Actual Year End Balance 2022	Actual Year End Balance 2023	Actual Year End Balance 2024
			(a)	(b)	(c)
			Note 1	Note 2	Note 3
	Regulated Hydroelectric:				
1	**Hydroelectric Water Conditions Variance**		(172.4)	(185.6)	(172.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(34.3)	(31.5)	(22.2)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		401.8	393.3	305.6
5	**Income and Other Taxes Variance - Hydroelectric**		(13.3)	(17.3)	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**		80.4	95.7	162.1
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.0	8.8	8.6
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		2.1	1.1	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		33.0	24.8	16.5
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		14.0	7.0	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		35.3	26.5	17.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		28.1	8.4	(8.0)
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(77.0)	(83.5)	(76.3)
14	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	4	(2.0)	(4.9)	(8.5)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.1	17.3	16.7
16	**Regulated Hydroelectric Subtotal**		319.9	260.0	222.3
	Nuclear:				
17	**Nuclear Liability Deferral**		188.3	377.5	527.3
18	**Nuclear Development Variance - DNNP**		110.9	106.7	61.8
19	**Nuclear Development Variance - Non-DNNP**		0.0	7.8	23.5
20	**Ancillary Services Net Revenue Variance - Nuclear**		(13.6)	(15.1)	(13.5)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**		(47.6)	121.4	170.2
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		49.7	146.5	173.7
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(30.9)	(25.8)	(16.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		79.4	83.3	70.1
25	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		84.2	63.2	42.1
26	**Bruce Lease Net Revenues Variance - Post 2017 Additions**		17.1	(4.2)	(102.0)
27	**Income and Other Taxes Variance - Nuclear**		(18.8)	(15.6)	(9.5)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		42.9	21.5	0.0
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(122.6)	(341.3)	(411.1)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		212.8	159.6	106.4
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		88.2	44.1	0.0
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		222.5	166.9	111.3
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	164.8	131.9
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(383.4)	(342.1)	(244.4)
35	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	4	(12.3)	(26.9)	(42.1)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(74.7)	(76.5)	(61.5)
37	**Fitness for Duty Deferral**		1.6	2.0	2.5
38	**SR&ED ITC Variance**		(8.6)	(23.3)	(25.7)
39	**Rate Smoothing Deferral**		568.9	653.8	677.4
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		(57.5)	24.4	85.1
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		(45.0)	9.6	66.1
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	0.0	(2.3)
43	**Pickering Closure Costs Deferral**		2.8	6.4	7.6
44	**Clarington Corporate Campus Deferral Account**		0.0	7.3	7.7
45	**Pickering B Variance**	5	0.0	26.5	131.1
46	**Nuclear Subtotal**		1,019.1	1,322.3	1,466.8
47	**Sale of Unprescribed Kipling Site Deferral**		0.0	(15.1)	(12.6)
48	**Total** (line 16 + line 46 + line 47)	6	1,339.0	1,567.1	1,676.5

Notes:
1 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.
2 From Ex. H1-1-1, Table 1a, col. (h).
3 From Ex. H1-1-1, Table 1b, col. (g).
4 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.
5 Established by *Ontario Regulation 53/05* , effective January 1, 2023 and as amended effective July 1, 2025.
6 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2023 ($M)

Line No.	Account	Note	Actual Year End Balance 2022	EB-2023-0336 Settlement Adjustments	(a)+(b) EB-2023-0336 Year-End Balance 2022	Actual 2023 Transactions	Amortization EB-2020-0290	Interest	Transfers	(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2023
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Note 1	Note 2			Note 3	Note 4		
	Hydroelectric:									
1	**Hydroelectric Water Conditions Variance**		(172.4)	0.0	(172.4)	(41.3)	36.4	(8.3)	0.0	(185.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(34.3)	0.0	(34.3)	(6.7)	11.1	(1.6)	0.0	(31.5)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		401.8	0.0	401.8	29.7	(56.1)	17.9	0.0	393.3
5	**Income and Other Taxes Variance - Hydroelectric**		(13.3)	0.0	(13.3)	(4.2)	0.9	(0.7)	0.0	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**	5	80.4	(4.7)	75.7	16.2	0.0	3.8	0.0	95.7
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.0	0.0	8.0	1.7	(1.3)	0.4	0.0	8.8
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		2.1	0.0	2.1	0.0	(1.1)	0.0	0.0	1.1
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		33.0	0.0	33.0	0.0	(8.3)	0.0	0.0	24.8
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		14.0	0.0	14.0	0.0	(7.0)	0.0	0.0	7.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		35.3	0.0	35.3	0.0	(8.8)	0.0	0.0	26.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		28.1	0.0	28.1	(19.7)	0.0	0.0	0.0	8.4
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(77.0)	0.0	(77.0)	(15.6)	12.9	(3.7)	0.0	(83.5)
14	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	6	(2.0)	0.0	(2.0)	(2.9)	0.0	0.0	0.0	(4.9)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.1	0.0	16.1	1.6	(1.1)	0.7	0.0	17.3
16	**Regulated Hydroelectric Subtotal**		319.9	(4.7)	315.1	(41.2)	(22.4)	8.4	0.0	260.0
	Nuclear:									
17	**Nuclear Liability Deferral**	9	188.3	0.0	188.3	189.14	0.0	0.0	0.0	377.5
18	**Nuclear Development Variance - DNNP**		110.9	(0.1)	110.8	(8.1)	(1.2)	5.3	0.0	106.7
19	**Nuclear Development Variance - Non-DNNP**		0.0	0.0	0.0	7.6	0.0	0.2	0.0	7.8
20	**Ancillary Services Net Revenue Variance - Nuclear**		(13.6)	0.0	(13.6)	(2.0)	1.2	(0.7)	0.0	(15.1)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**	9	(47.6)	0.0	(47.6)	168.1	0.0	0.9	0.0	121.4
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**	9	49.7	(4.2)	45.6	64.2	32.0	4.6	0.0	146.5
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(30.9)	0.0	(30.9)	0.0	6.4	(1.3)	0.0	(25.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		79.4	0.0	79.4	0.0	(0.0)	3.9	0.0	83.3
25	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		84.2	0.0	84.2	0.0	(21.1)	0.0	0.0	63.2
26	**Bruce Lease Net Revenues Variance - Post 2017 Additions**	9	17.1	0.0	17.1	(16.9)	(7.7)	3.3	0.0	(4.2)
27	**Income and Other Taxes Variance - Nuclear**		(18.8)	0.0	(18.8)	(1.0)	4.8	(0.7)	0.0	(15.6)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		42.9	0.0	42.9	0.0	(21.5)	0.0	0.0	21.5
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(122.6)	0.0	(122.6)	(218.7)	0.0	0.0	0.0	(341.3)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		212.8	0.0	212.8	0.0	(53.2)	0.0	0.0	159.6
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		88.2	0.0	88.2	0.0	(44.1)	0.0	0.0	44.1
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		222.5	0.0	222.5	0.0	(55.6)	0.0	0.0	166.9
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	0.0	164.8	0.0	0.0	0.0	0.0	164.8
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(383.4)	0.0	(383.4)	0.0	58.1	(16.8)	0.0	(342.1)
35	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	6	(12.3)	0.0	(12.3)	(14.8)	0.2	0.0	0.0	(26.9)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(74.7)	0.0	(74.7)	(6.1)	8.4	(4.1)	0.0	(76.5)
37	**Fitness for Duty Deferral**	11	1.6	0.0	1.6	0.4	0.0	0.1	0.0	2.0
38	**SR&ED ITC Variance**		(8.6)	0.0	(8.6)	(18.0)	4.0	(0.7)	0.0	(23.3)
39	**Rate Smoothing Deferral**	10	568.9	0.0	568.9	64.0	0.0	20.9	0.0	653.8
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		(57.5)	0.0	(57.5)	0.0	81.9	0.0	0.0	24.4
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		(45.0)	0.0	(45.0)	54.6	0.0	0.0	0.0	9.6
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	**Pickering Closure Costs Deferral**	12	2.8	0.0	2.8	3.4	0.0	0.2	0.0	6.4
44	**Clarington Corporate Campus Deferral Account**		0.0	0.0	0.0	7.0	0.0	0.3	0.0	7.3
45	**Pickering B Variance**		0.0	0.0	0.0	26.2	0.0	0.3	0.0	26.5
46	**Nuclear Subtotal**		1,019.1	(4.3)	1,014.8	299.1	(7.3)	15.7	0.0	1,322.3
47	**Sale of Unprescribed Kipling Site Deferral**	7	0.0	(12.7)	(12.7)	(2.5)	0.0	0.0	0.0	(15.1)
48	**Total** (line 16 + line 46 + line 47)	8	1,339.0	(21.7)	1,317.3	255.4	(29.7)	24.1	0.0	1,567.1

Notes:

1 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.

2 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (c1) for regulated hydroelectric and Table 2, col. (c1) for nuclear.

3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (i) for Regulated Hydroelectric, and App. D, Table 1, col. (i) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The year-end 2022 balance has been updated from that presented in EB-2023-0336 to reflect changes identified in the course of preparing this application.

6 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

7 The year-end 2022 balance has been updated from that presented in EB-2023-0336 pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5. Account transactions in 2023 recorded pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5, and represent 50% of the 23% of an incremental $21.5M after-tax gain recognized by OPG in 2023 associated with the sale of the Kipling Site.

8 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

9 Includes the following adjustments, presented as part of 2023 transactions in col. (d): (i) reduction of $4.1M in line 17 and addition of $2.1M in line 26 to reflect the 2022 impact of updated calculations to the dollar per cubic metre cost rates for low and intermediate level waste ("L&ILW") based on the 2022 ONFA Reference Plan ("Reference Plan"); (ii) net addition of $0.8M in line 21, reflecting the combined impact of $1.4M reduction for updated calculations to the dollar per cubic metre cost rates for L&ILW in 2022 and $2.2M addition to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application; and (iii) reduction of $0.4M in line 22 to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application.

10 The year-end 2022 balance comprises deferral amounts recorded from 2017 to 2021 per EB-2016-0152 Payment Amounts Order, App. H, p. 1: 2017 - $0M, 2018 - $0M, 2019 - $102.2M, 2020 - $390.6M, 2021 - $0M; deferral amount of $19.0M recorded in 2022 per EB-2020-0290 Payment Amounts Order, App. B, Table 1; and interest on the account balance recorded at the following OPG long-term debt rates, compounded annually: 2019 - 4.52%, 2020 - 4.49%, 2021 - 4.48% (EB-2016-0152 Payment Amounts Order, App. H, p. 2) and 3.61% in 2022 (EB-2020-0290 Payment Amounts Order, App. E, p. 19). Transactions in 2023 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

11 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2017 - $0.1M, 2018 - $0.1M, 2019 - $0.3M, 2020 - $0.1M, 2021 - $0.5M and 2022 - $0.4M, plus interest on the account balance at the OEB's prescribed interest rate.

12 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2021 - $1.0M and 2022 - $1.8M, plus interest on the account balance at the OEB's prescribed interest.

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2024 ($M)

Line No.	Account	Note	Actual Year End Balance 2023	Actual 2024 Transactions	Actual 2024 Amortization EB-2020-0290	Actual 2024 Amortization EB-2023-0336	Actual 2024 Interest	Actual 2024 Transfers	(c)+(d)+(e)+(f)+(g) Audited Year End Balance 2024
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1		Note 2	Note 3	Note 4		
	Hydroelectric:								
1	**Hydroelectric Water Conditions Variance**		(185.6)	(35.1)	36.4	19.9	(8.2)	0.0	(172.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(31.5)	(3.0)	11.1	2.4	(1.2)	0.0	(22.2)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		393.3	10.6	(56.1)	(57.9)	15.7	0.0	305.6
5	**Income and Other Taxes Variance - Hydroelectric**		(17.3)	(2.3)	0.9	2.3	(0.8)	0.0	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**		95.7	72.0	0.0	(10.3)	4.7	0.0	162.1
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.8	1.7	(1.3)	(1.1)	0.4	0.0	8.6
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		1.1	0.0	(1.1)	0.0	0.0	0.0	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		24.8	0.0	(8.3)	0.0	0.0	0.0	16.5
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		7.0	0.0	(7.0)	0.0	0.0	0.0	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		26.5	0.0	(8.8)	0.0	0.0	0.0	17.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		8.4	(10.8)	0.0	(5.6)	0.0	0.0	(8.0)
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(83.5)	(12.1)	12.9	10.3	(3.8)	0.0	(76.3)
14	**Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	5	(4.9)	(4.0)	0.0	0.4	0.0	0.0	(8.5)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		17.3	2.6	(1.1)	(2.8)	0.7	0.0	16.7
16	**Regulated Hydroelectric Subtotal**		260.0	19.6	(22.4)	(42.5)	7.6	0.0	222.3
	Nuclear:								
17	**Nuclear Liability Deferral**		377.5	187.5	0.0	(37.7)	0.0	0.0	527.3
18	**Nuclear Development Variance - DNNP**		106.7	(26.5)	(1.2)	(21.7)	4.5	0.0	61.8
19	**Nuclear Development Variance - Non-DNNP**		7.8	15.1	0.0	0.0	0.6	0.0	23.5
20	**Ancillary Services Net Revenue Variance - Nuclear**		(15.1)	(1.1)	1.2	2.3	(0.7)	0.0	(13.5)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**		121.4	41.5	0.0	0.0	7.3	0.0	170.2
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		146.5	9.3	32.0	(22.4)	8.3	0.0	173.7
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(25.8)	0.0	6.4	3.6	(1.0)	0.0	(16.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		83.3	0.0	(0.0)	(15.9)	2.8	0.0	70.1
25	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved**		63.2	0.0	(21.1)	0.0	0.0	0.0	42.1
26	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2017 Additions**		(4.2)	(89.2)	(7.7)	(0.3)	(0.7)	0.0	(102.0)
27	**Income and Other Taxes Variance - Nuclear**		(15.6)	0.0	4.8	1.8	(0.5)	0.0	(9.5)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		21.5	0.0	(21.5)	0.0	0.0	0.0	0.0
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(341.3)	(94.4)	0.0	24.5	0.0	0.0	(411.1)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		159.6	0.0	(53.2)	0.0	0.0	0.0	106.4
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		44.1	0.0	(44.1)	0.0	0.0	0.0	0.0
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		166.9	0.0	(55.6)	0.0	0.0	0.0	111.3
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	0.0	0.0	(33.0)	0.0	0.0	131.9
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(342.1)	0.0	58.1	53.5	(13.8)	0.0	(244.4)
35	**Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	5	(26.9)	(17.8)	0.2	2.4	0.0	0.0	(42.1)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(76.5)	(1.2)	8.4	11.6	(3.7)	0.0	(61.5)
37	**Fitness for Duty Deferral**	8	2.0	0.4	0.0	0.0	0.1	0.0	2.5
38	**SR&ED ITC Variance**		(23.3)	(5.5)	4.0	0.1	(1.0)	0.0	(25.7)
39	**Rate Smoothing Deferral**	7	653.8	0.0	0.0	0.0	23.6	0.0	677.4
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		24.4	0.0	81.9	(21.3)	0.0	0.0	85.1
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		9.6	47.4	0.0	9.0	0.0	0.0	66.1
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	(2.3)	0.0	0.0	0.0	0.0	(2.3)
43	**Pickering Closure Costs Deferral**	8	6.4	0.9	0.0	0.0	0.3	0.0	7.6
44	**Clarington Corporate Campus Deferral Account**		7.3	0.0	0.0	0.0	0.4	0.0	7.7
45	**Pickering B Variance**		26.5	101.4	0.0	0.0	3.3	0.0	131.1
46	**Nuclear Subtotal**		1,322.3	165.4	(7.3)	(43.4)	29.9	0.0	1,466.8
47	**Sale of Unprescribed Kipling Site Deferral**		(15.1)	0.0	0.0	2.5	0.0	0.0	(12.6)
48	**Total** (line 16 + line 46 + line 47)	6	1,567.1	184.9	(29.7)	(83.3)	37.5	0.0	1,676.5

Notes:

1. From Ex. H-1-1-1, Table 1a, col. (h).
2. From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (j) for Regulated Hydroelectric and App. D, Table 1, col. (j) for Nuclear.
3. From EB-2023-0336 Decision and Order, App. A, Table 1, col. (g) for Regulated Hydroelectric and Table 2, col. (g) for Nuclear.
4. Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.
5. The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.
6. The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.
7. Transactions in 2024 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.
8. Account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements.

Numbers may not add due to rounding.

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Forecast Production (GWh)**	1	32,432	32,432
2	**Actual Calculated Production (GWh)**		33,898	33,650
3	**Difference (GWh)** (line 1 - line 2)		(1,466)	(1,218)
4	**Payment Amount ($/MWh)**	2	43.88	43.88
5	**Revenue Impact ($M)** (line 3 x line 4 / 1000)		(64.3)	(53.5)
6	**GRC/Water Rental Costs ($M)**		23.1	18.4
7	**Total Addition to Variance Account ($M)** (line 5 + line 6)		(41.3)	(35.1)

Notes:
1 Cols. (a) and (b) as set out in EB-2020-0290 Payment Amounts Order, App. E, pp. 3-4.
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, p. 4.

Table 3
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Forecast Revenue**	1	55.5	55.5
2	**Actual Revenue**	2	62.3	58.5
3	**Regulated Hydroelectric Addition to Variance Account** (line 1 - line 2)		(6.7)	(3.0)
	Nuclear:			
4	**Forecast Revenue**	1	6.3	6.1
5	**Actual Revenue**	2	8.3	7.3
6	**Nuclear Addition to Variance Account** (line 4 - line 5)		(2.0)	(1.1)

Notes:
1 Cols. (a) and (b) as per EB-2020-0290 Payment Amounts Order, App. E, pp. 4-5.
2 As shown in G1-1-1, Table 1, line 1, cols. (h) and (i) for regulated hydroelectric. As shown in G2-1-1, Table 1, line 6, cols. (d) and (e) for nuclear.

Numbers may not add due to rounding.

Table 4
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Total Actual Regulated Hydroelectric Incentive Mechanism Net Revenue**	1	14.8	28.4
2	**Threshold**	2	54.5	54.5
3	**Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold** (line 1 - line 2; nil if line 1 < line 2)		0.0	0.0
4	**Percentage**	2	50%	50%
5	**Total Addition to Variance Account** (line 3 x line 4)		0.0	0.0

Notes:
1 Annual values as reported in OPG's 2024 Management's Discussion & Analysis (p. 51) for 2023 and 2024.
2 Annual threshold and percentage per EB-2014-0370 Payment Amounts Order, App. B, pp. 8-9.

Numbers may not add due to rounding.

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Actual Foregone Production Due to SBG Conditions (GWh)**	1	977	350
2	**Payment Amount ($/MWh)**	2	43.88	43.88
3	**Revenue ($M)** (line 1 x line 2 / 1000)		42.9	15.3
4	**GRC/Water Rental Costs ($M)**		(13.2)	(4.7)
5	**Total Addition to Variance Account ($M)** (line 3 + line 4)		29.7	10.6

Notes:
1 Annual values are reported in OPG's 2024 Management's Discussion & Analysis (p.14) for 2023 and 2024.
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, p.5.

Table 6
Income and Other Taxes Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023 Regulated Hydroelectric	Actual 2023 Nuclear	Actual 2023 (a) + (b) Total	Actual 2024 Regulated Hydroelectric	Actual 2024 Nuclear	Actual 2024 (d) + (e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
	Entry (i): CCA Accelerated Investment Incentive Property Impact	1						
1	**2023 CCA differences**		(11.2)	0.0	(11.2)	0.0	0.0	0.0
2	**2024 CCA differences**		0.0	0.0	0.0	(6.4)	0.0	(6.4)
3	**Income Tax Impact for 2023** (line 1 x 25%)		(2.8)	0.0	(2.8)	0.0	0.0	0.0
4	**Income Tax Impact for 2024** (line 2 x 25%)		0.0	0.0	0.0	(1.6)	0.0	(1.6)
5	**Addition to Variance Account** (line 3 + line 4) / (1-25%)		(3.7)	0.0	(3.7)	(2.1)	0.0	(2.1)
	Entry (ii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017	2						
6	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		(0.7)	(2.9)	(3.7)	0.0	0.0	0.0
7	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 6 x 4/3)		(1.0)	(3.9)	(4.9)	0.0	0.0	0.0
8	**Addition to Variance Account** (line 7 - line 6)		(0.2)	(1.0)	(1.2)	0.0	0.0	0.0
	Entry (iii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	3						
9	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		(0.7)	0.0	(0.7)	0.0	0.0	0.0
10	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 9 x 4/3)		(1.0)	0.0	(1.0)	0.0	0.0	0.0
11	**Addition to Variance Account** (line 10 - line 9)		(0.2)	0.0	(0.2)	0.0	0.0	0.0
	Entry (iv) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	4						
12	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		0.0	0.0	0.0	(0.7)	0.0	(0.7)
13	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 12 x 4/3)		0.0	0.0	0.0	(1.0)	0.0	(1.0)
14	**Addition to Variance Account** (line 13 - line 12)		0.0	0.0	0.0	(0.2)	0.0	(0.2)
	Entry (v): Ontario Research and Development Tax Credit (ORDTC) Reduction from 4.5% to 3.5% Effective June 1, 2016							
15	**Addition to Variance Account - Reduction in ORDTC Rate**		0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Addition to Variance Account** (line 5 + line 8 + line 11 + line 14 + line 15)		(4.2)	(1.0)	(5.2)	(2.3)	0.0	(2.3)

Notes:

1 Recorded to reflect the impact of changes in Capital Cost Allowance (CCA) rules, whereby taxpayers can claim higher first-year CCA deductions on eligible capital assets acquired after November 20, 2018, for assets other than those subject to the Capacity Refurbishment Variance Account (CRVA) and the Nuclear Development Variance Account (NDVA). The impact of this rule change for assets subject to the CRVA and NDVA are recorded in the respective accounts as part of the total CCA variances for eligible projects. No entries have been recorded for the nuclear facilities beginning January 1, 2022 as the impact of this rule change was reflected in the EB-2020-0290 nuclear revenue requirements.

2 Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount at line 7 represents SR&ED ITCs, net of tax on ITCs, for 2017 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts. For the nuclear facilities, the amount at line 7 represents the January 1 to May 31, 2017 portion of said credit. The June 1 to December 31, 2017 portion for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

3 Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount at line 10 represents SR&ED ITCs, net of tax on ITCs, for 2018 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

4 Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount at line 13 represents SR&ED ITCs, net of tax on ITCs, for 2019 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

Numbers may not add due to rounding.

Table 7
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023 Regulated Hydroelectric	Actual 2023 Nuclear[4]	Actual 2023 (a)+(b) Total	Actual 2024 Regulated Hydroelectric	Actual 2024 Nuclear[4]	Actual 2024 (d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Pension Contributions**	1	45.1	0.0	45.1	45.1	0.0	45.1
2	**Forecast OPEB Payments**	1	12.8	0.0	12.8	12.8	0.0	12.8
3	**Total Forecast Pension and OPEB Cash Amounts** (line 1 + line 2)		58.0	0.0	58.0	58.0	0.0	58.0
4	**Actual Pension Contributions**	2	23.1	0.0	23.1	27.6	0.0	27.6
5	**Actual OPEB Payments**	2	19.2	0.0	19.2	18.2	0.0	18.2
6	**Total Actual Pension and OPEB Cash Amounts** (line 4 + line 5)		42.3	0.0	42.3	45.8	0.0	45.8
7	**Total Addition to Pension & OPEB Cash Payment Variance Account** (line 6 - line 3)		(15.6)	0.0	(15.6)	(12.1)	0.0	(12.1)
8	**Actual Pension - Registered Pension Plan (RPP) Accrual Costs**	3	(5.0)	0.0	(5.0)	8.1	0.0	8.1
9	**Actual OPEB - Non-RPP Accrual Costs**	3	27.7	0.0	27.7	27.0	0.0	27.0
10	**Total Actual Pension and OPEB Accrual** (line 8 + line 9)		22.6	0.0	22.6	35.1	0.0	35.1
11	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - RPP** (line 8 - line 4)		(28.1)	0.0	(28.1)	(19.6)	0.0	(19.6)
12	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - Non-RPP** (line 9 - line 5)		8.4	0.0	8.4	8.8	0.0	8.8
13	**Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account** (line 11 + line 12)		(19.7)	0.0	(19.7)	(10.8)	0.0	(10.8)

Notes:
1. Cols. (a) and (d) are per EB-2020-0290 Payment Amounts Order, App. E, p. 12.
2. Represents the portion of OPG's actual pension contributions and OPEB payments for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp.9-10, attributed to the regulated hydroelectric facilities.
3. Represents the portion of OPG's actual pension and OPEB costs for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the regulated hydroelectric facilities.
4. As per the EB-2020-0290 Payment Amounts Order, App. E, p. 12, no additions are recorded to the Pension & OPEB Cash Payment Variance Account or the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the nuclear facilities beginning in 2022 as the nuclear revenue requirements approved in that proceeding reflected pension and OPEB costs calculated on an accrual basis.

Table 7a

Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account - Primary, Contra and Carrying Charges Sub-Accounts

Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023 Regulated Hydroelectric	Actual 2023 Nuclear	Actual 2023 (a)+(b) Total	Actual 2024 Regulated Hydroelectric	Actual 2024 Nuclear	Actual 2024 (d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Registered Pension Plan (RPP) - EB-2018-0243 Approved**	1	8.3	53.2	61.5	8.3	53.2	61.5
2	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Non-RPP - EB-2018-0243 Approved**	1	7.0	44.1	51.1	7.0	44.1	51.1
3	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2017 Additions - EB-2020-0290 Approved**	1	8.8	55.6	64.5	8.8	55.6	64.5
4	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2019 Additions**	2	0.0	0.0	0.0	5.6	33.0	38.6
5	**Actual Pension and OPEB Accrual Costs - Nuclear**	3	0.0	125.6	125.6	0.0	205.2	205.2
6	**Actual Pension and OPEB Cash Amounts - Nuclear**	4	0.0	234.9	234.9	0.0	268.2	268.2
7	**Total Addition to Primary Sub-Account Tracking Balance** (line 1 + line 2 + line 3 + line 4 + line 5 - line 6)		24.1	43.6	67.6	29.7	122.8	152.5
8	**Total Addition to Contra Sub-Account Tracking Balance** (line 7 x -1)		(24.1)	(43.6)	(67.6)	(29.7)	(122.8)	(152.5)
9	**Net Total Addition to Primary and Contra Sub-Accounts Tracking Balances**		0.0	0.0	0.0	0.0	0.0	0.0
10	**Primary Sub-Account Tracking Credit Balance - Opening**	5	45.0	267.4	312.4	69.1	310.9	380.0
11	**Primary Sub-Account Tracking Credit Balance - Closing** (line 7 + line 10)		69.1	310.9	380.0	98.7	433.8	532.5
12	**Total Addition to Carrying Charges Sub-Account**	6	(2.9)	(14.8)	(17.6)	(4.0)	(17.8)	(21.9)

Notes:

1 Col. (a) and (d) per EB-2020-0290 Payment Amounts Order, App. C, Table 1, lines 10-12, col. (i) and (j), respectively. Cols. (b) and (e) per EB-2020-0290 Payment Amounts Order, App. D, Table 1, lines 15-17, col. (i) and (j), respectively.

2 Col. (d) per EB-2023-0336 Decision and Order, App. A, Table 1, line 12, col. (g). Col. (e) per EB-2023-0336 Decision and Order, App. A, Table 2, line 16, col. (g).

3 Cols. (b) and (e) from Ex. H1-1-1, Table 7b, line 6, cols. (a) and (b), respectively.

4 Cols. (b) and (e) represents the portion of OPG's actual pension contributions and OPEB payments for 2023 and 2024 respectively, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

5 Cols. (a) and (b) from EB-2023-0336, Ex. H1-1-1, Table 8a, line 10, cols. (g) and (h), respectively. Cols. (d) and (e) are equal to line 11 of the preceding year.

6 Carrying charges are calculated on the monthly opening cumulative balance in the Primary Sub-Account (when in a credit position) using the OEB's prescribed Construction Work in Progress rate, as follows: 2023 - 5.01% for Q1 to Q3 and 5.48% for Q4; 2024 - 5.48% for Q1, 4.98% for Q2 to Q3 and 4.55% for Q4.

Table 7b
Pension and OPEB Cost Variance Account - Nuclear
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Forecast Accrual Pension Costs**	1	134.3	111.7
2	**Forecast Accrual OPEB Costs**	1	159.9	161.0
3	**Total Forecast Accrual Pension and OPEB Costs** (line 1 + line 2)	2	294.1	272.7
4	**Actual Accrual Pension Costs**	3	(27.9)	47.2
5	**Actual Accrual OPEB Costs**	3	153.5	158.0
6	**Total Actual Accrual Pension and OPEB Costs** (line 4 + line 5)		125.6	205.2
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		(162.2)	(64.5)
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		(6.3)	(3.0)
9	**Addition to Variance Account - Income Tax Impact**	4	(50.2)	(26.8)
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		(218.7)	(94.4)

Notes:
1 From EB-2020-0290, Ex. F4-3-2, Chart 1.
2 From EB-2020-0290 Payment Amounts Order, App. E, p.10, line 27.
3 Represents the portion of OPG's actual pension and OPEB costs in 2023 and 2024, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.
4 Table to Note 4 - The income tax impact of the pension and OPEB cost additions to the account is calculated as follows ($M):

Line No.		Note	Actual 2023	Actual 2024
			(a)	(b)
1a	Forecast Income Tax Impact	*	13.7	5.8
	Actual Additions to / Deductions from Regulatory Earnings Before Tax:			
2a	Actual Accrual Pension Costs (line 4)		(27.9)	47.2
3a	Actual Accrual OPEB Costs (line 5)		153.5	158.0
4a	Less: Actual Pension Contributions	**	128.2	161.7
5a	Less: Actual OPEB Payments	**	106.8	106.5
6a	Net Additions to Regulatory Earnings Before Tax (line 2a + line 3a - line 4a - line 5a)		(109.3)	(63.0)
7a	Actual Income Tax Impact (line 6a x 25% / (1 - 25%))		(36.4)	(21.0)
8a	Addition to Variance Account - Income Tax Impact (line 7a - line 1a)		(50.2)	(26.8)

* From EB-2020-0290 Payment Amounts Order, App. E, p. 11, line 2.
** Represents the portion of OPG's actual pension contributions and OPEB payments in 2023 and 2024, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

Numbers may not add due to rounding.

Table 8
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Regulated Hydroelectric Rider ($/MWh)-EB-2020-0290**	1	1.03	1.03
2	**Regulated Hydroelectric Rider ($/MWh)-EB-2023-0336**	2		2.61
3	**Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2020-0290**	3	33.0	33.0
4	**Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2023-0336**	4		16.5
5	**Regulated Hydroelectric Actual Production (TWh)**	5	31.4	32.5
6	**Regulated Hydroelectric Actual Production (TWh) - For Six Months Beginning July 1, 2024**			15.7
7	**Production Variance for Regulated Hydroelectric Rider (TWh) EB-2020-0290** (line 3 - line 5)		1.6	0.5
8	**Production Variance for Regulated Hydroelectric Rider (TWh) EB-2023-0336** (line 4 - line 6)			0.8
9	**Addition to Variance Account ($M)** - **Regulated Hydroelectric Rider-EB-2020-0290** (line 7 x line 1)		1.6	0.5
10	**Addition to Variance Account ($M)** - **Regulated Hydroelectric Rider-EB-2023-0336** (line 8 x line 2)			2.1
11	**Addition to Variance Account ($M)** (line 9 + line 10)		1.6	2.6

Notes:
1 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 23, cols. (i) and (j).
2 From EB-2023-0336 Decision and Order, App. A, Table 1, line 21, col. (g).
3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 22, cols. (i) and (j).
4 From EB-2023-0336 Decision and Order, App. A, Table 1, line 20, col. (g).
5 From Ex. E1-1-1, Table 1, line 4, cols. (h) and (i).

Numbers may not add due to rounding.

Table 9
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
1	**Actual Net Plant Rate Base Amount**	1	19.3	19.0
2	**Weighted Average Cost of Capital**	2	6.85%	6.85%
3	**Actual Cost of Capital Amount** (line 1 x line 2)		1.3	1.3
4	**Cost of Capital Variance**		1.3	1.3
5	**Forecast Depreciation**		0.0	0.0
6	**Actual Depreciation**		0.2	0.2
7	**Depreciation Variance** (line 6 - line 5)		0.2	0.2
	Income Tax Impact:			
8	**Forecast Capital Cost Allowance Deduction**		0.0	0.0
9	**Actual Capital Cost Allowance Deduction**		0.6	0.6
10	**Difference** (line 8 - line 9)		(0.6)	(0.6)
11	**Net Increase in Regulatory Taxable Income**	3	0.4	0.5
12	**Income Tax Rate**	4	25%	25%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))		0.1	0.2
14	**Total Addition to Variance Account** (line 4 + line 7 + line 13)		1.7	1.7

Notes:

1 The continuity of the variation between the original Niagara Tunnel Project rate base disallowance of $28M and the varied disallowance of $6.4M is as follows:

	Table to Note 1 - Niagara Tunnel Project Disallowance Continuity ($M)		
Line No.		2023	2024
		(a)	(b)
1a	Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 10, line 4a, col. (c))	19.4	19.1
2a	In-Service	0.0	0.0
3a	Depreciation Expense (line 6)	(0.2)	(0.2)
4a	Closing Balance	19.1	18.9
5a	Actual Net Plant Rate Base Amount (lines 1a+ 4a)/ 2	19.3	19.0

2 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).

3 The change in regulatory taxable income is calculated as the sum of lines 7 and 10, plus the ROE component of the cost of capital variance at line 4. The ROE component of the variance is equal to line 1 multiplied by the OEB-approved equity portion (45%) of the capital structure, multiplied by the EB-2013-0321 OEB-approved ROE rate of 9.30%.

4 From EB-2013-0321 Payment Amounts Order, App. A, Table 8, line 31, col. (c).

Table 10
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Actual Total Bruce Lease Net Revenues ($M)**	1	(25.8)	42.5
2	**Forecast Bruce Lease Net Revenue**	2	(38.7)	(48.1)
3	**Forecast Nuclear Production (TWh)**	3	31.2	34.0
4	**Rate Credited to (Recovered from) Customers ($/MWh)** (line 2 / line 3)	4	(1.24)	(1.42)
5	**Actual Nuclear Production (TWh)**	5	36.1	33.0
6	**Amount Credited to (Recovered from) Customers ($M)** (line 4 x line 5)		(44.8)	(46.7)
7	**Total Addition to Variance Account ($M)** (line 6 - line 1)		(19.0)	(89.2)

Notes:
1 From Ex. G2-2-1, Table 1, line 3, cols. (d) and (e).
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
3 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 2, cols. (b) and (c), respectively.
4 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
5 From Ex. E2-1-1, Table 1, line 3, cols. (d) and (e).

Table 11
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Nuclear Rider ($/MWh)-EB-2020-0290**	1	1.25	1.15
2	**Nuclear Rider ($/MWh)-EB-2023-0336**	2		3.13
3	**Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2020-0290**	3	31.2	34.0
4	**Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2023-0336**	4		17.0
5	**Actual Nuclear Production (TWh)**	5	36.1	33.0
6	**Actual Nuclear Production (TWh) - For Six Months Beginning July 1, 2024**			17.7
7	**Production Variance for Nuclear Rider (TWh) EB 2020-0290** (line 3 - line 5)		(4.9)	1.03
8	**Production Variance for Nuclear Rider (TWh) EB 2023-0336** (line 4 - line 6)			(0.8)
9	**Addition To Variance Account - Nuclear Rider-EB-2020-0290** (line 7 x line 1)		(6.1)	1.2
10	**Addition To Variance Account - Nuclear Rider-EB-2023-0336** (line 8 x line 2)			(2.4)
11	**Addition To Variance Account** (line 9 + line 10)		(6.1)	(1.2)

Notes:
1. From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 32, cols. (i) and (j).
2. From EB-2023-0336 Decision and Order, App. A, Table 2, line 31, col. (g)
3. From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 31, cols. (i) and (j).
4. From EB-2023-0336 Decision and Order, App. A, Table 2, line 30, col. (g).
5. From Ex. E2-1-1, Table 1, line 3, cols. (d) and (e).

Table 12
SR&ED ITCs Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Entry (i): Additions Based on Current Year Tax Provision			
1	**Forecast Annual SR&ED ITCs**	1	16.3	16.4
2	**Less: Tax on Provincial Portion Taxable in Current Year**		(0.8)	(0.8)
3	**Less: Tax on Federal ITC in Prior Year**		(3.3)	(3.3)
4	**Forecast Annual SR&ED ITCs, net of Tax**		12.2	12.3
5	**Actual Annual SR&ED ITCs Recorded in the Year**		19.7	15.0
6	**Less: Tax on Provincial Portion Taxable in Current Year**		(1.0)	(0.7)
7	**Less: Tax on Federal ITC in Prior Year**		(4.0)	(4.4)
8	**Actual Annual SR&ED ITCs Recorded, net of Tax**		14.8	9.9
9	**Addition to Variance Account based on Current Year Tax Provision** ((line 4 - line 8) / (1-25%))		(3.4)	3.2
	Entry (ii): True Up Adjustments Based on Prior Year's Income Tax Return			
10	**Actual Annual SR&ED ITCs Recorded, net of Tax**	2	13.5	14.8
11	**Prior Year Actual Annual SR&ED ITCs per Income Tax Return Completed in Current Year**		19.7	21.6
12	**Less: Tax on Provincial Portion Taxable in Current Year**		(1.0)	(1.1)
13	**Less: Tax on Federal ITC in Prior Year**		(4.1)	(4.0)
14	**Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of Tax**		14.7	16.6
15	**True-Up Adjustment Based on Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of tax** (line 10 - line 14)	3	(1.2)	(1.8)
16	**Addition to Variance Account based on True-Up Adjustments based on Prior Year's Income Tax Return** (line 15 / (1-25%))		(1.6)	(2.4)
	Entry (iii): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017 from June 1 to December 31, 2017	4		
17	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		(12.1)	0.0
18	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 17 x 4/3)		(16.2)	0.0
19	**Addition to Variance Account** ((line 18 - line 17) / (1-25%))		(5.4)	0.0
	Entry (iv): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	5		
20	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		(16.9)	0.0
21	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 20 x 4/3)		(22.6)	0.0
22	**Addition to Variance Account** ((line 21 - line 20) / (1-25%))		(7.5)	0.0
	Entry (v): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	6		
23	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		0.0	(14.2)
24	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 23 x 4/3)		0.0	(18.9)
25	**Addition to Variance Account** ((line 24 - line 23) / (1-25%))		0.0	(6.3)
26	**Total Addition to Variance Account** (line 9 + line 16 + line 19 + line 22+ line 25)		(18.0)	(5.5)

Notes:
1 Cols. (a) and (b) per EB-2020-0290 Payment Amounts Order, App. E, p. 18.
2 Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 14, line 8, col (c). Col. (b) from line 8, col. (a).
3 Represents the adjustment based on the final ITC values determined in 2023 and 2024 as part of the filing of the 2022 and 2023 income tax returns and trued up as part of the 2023 and 2024 entries to the variance account, respectively.
4 Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount in line 17 represents the June 1 to December 31, 2017 portion of SR&ED ITCs, net of tax on ITCs, for the nuclear faciliites for 2017 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., 7/12 x EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (a)) . The SR&ED ITC Variance Account became effective on June 1, 2017.
5 Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount in line 20 represents the SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2018 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (b)).
6 Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount in line 23 represents actual SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2019 previously credited to ratepayers at 75% through EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB 2023-0336, Ex. H1-1-1, Table 14, line 11, col. (a)).

Table 13
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - Non DRP
Summary of Account Transactions 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Non-Capital Addition to Variance Account - Non-DRP			
	Forecast Non-Capital Costs:			
1	**Pickering Extended Operations**	1	0.0	0.0
2	**Fuel Channel Life Extension Project**	1	0.0	0.0
3	**FCLE Related Ongoing Costs**	1	18.7	1.1
4	**Darlington U3 Fuel Channel Component Retrieval Project**	1	0.0	0.0
5	**Darlington Annulus Spacer Life Management Project**		0.0	0.0
6	**Pickering B Refurbishment Feasibility Assessment**		0.0	0.0
7	**Darlington Steam Generator Primary Moisture Separators Replacement**		0.0	0.0
8	**Optimization of Pickering Shutdown**	1	4.9	18.4
9	**Fuel Channel Life Management Phase V Project**		0.0	0.0
10	**Total** (lines 1 through 9)	2	23.6	19.4
	Actual Non-Capital Costs:	3		
11	**Pickering Extended Operations**		0.4	0.0
12	**Fuel Channel Life Extension Project**		3.0	(0.1)
13	**FCLE Related Ongoing Costs**		46.8	1.9
14	**Darlington U3 Fuel Channel Component Retrieval Project**		0.1	0.0
15	**Darlington Annulus Spacer Life Management Project**		0.4	0.0
16	**Pickering B Refurbishment Feasibility Assessment**		17.8	0.0
17	**Darlington Steam Generator Primary Moisture Separators Replacement**		4.5	3.8
18	**Optimization of Pickering Shutdown**		11.6	15.0
19	**Fuel Channel Life Management Phase V Project**		1.1	5.3
20	**Total** (lines 11 through 19)		85.7	25.9
	Non-Capital Addition to Variance Account:			
21	**Pickering Extended Operations** (line 11 - line 1)		0.4	0.0
22	**Fuel Channel Life Extension Project** (line 12 - line 2)		3.0	(0.1)
23	**FCLE Related Ongoing Costs** (line 13 - line 3)		28.0	0.8
24	**Darlington U3 Fuel Channel Component Retrieval Project** (line 14 - line 4)		0.1	0.0
25	**Darlington Annulus Spacer Life Management Project** (line 15 - line 5)		0.4	0.0
26	**Pickering B Refurbishment Feasibility Assessment** (line 16 - line 6)		17.8	0.0
27	**Darlington Steam Generator Primary Moisture Separators** (line 17 - line 7)		4.5	3.8
28	**Optimization of Pickering Shutdown** (line 18 - line 8)		6.7	(3.4)
29	**Fuel Channel Life Management Phase V Project** (line 19 - line 9)		1.1	5.3
30	**Non-Capital Addition to Variance Account** (lines 21 through 29)		62.1	6.5

Notes:
1 Cols. (a) and (b) from EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 1.
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 9.
3 Details for actual non-capital costs can be found at Ex. F2-1-1, Table 1a, F2-2-1, Table 1a, F2-3-1, Table 1, and Ex. F2-4-1, Table 1.

Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
1	**Forecast Cost of Capital Amount**	1	0.8	0.3
2	**Actual Net Plant Rate Base Amount**	2	68.5	151.5
3	**Weighted Average Cost of Capital**	1	5.83%	5.90%
4	**Actual Cost of Capital Amount** (line 2 x 3)		4.0	8.9
5	**Cost of Capital Variance** (line 4 - line 1)		3.2	8.6
6	**Forecast Depreciation**	1	8.8	8.8
7	**Actual Depreciation**	2	11.5	9.9
8	**Depreciation Variance** (line 7 - line 6)		2.7	1.1
	Income Tax Impact			
9	**Forecast Capital Cost Allowance Deduction**	1	1.9	1.7
10	**Actual Capital Cost Allowance Deduction**		12.0	14.6
11	**Actual SR&ED Qualifying Capital Expenditures**		4.8	14.7
12	**Difference** (line 9 - line 10 - line 11)		(14.9)	(27.5)
13	**Net Increase (Decrease) in Regulatory Taxable Income**	3	(10.1)	(20.8)
14	**Income Tax Rate**		25.0%	25.0%
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		(3.4)	(6.9)
16	**Capital Addition to Variance Account - Non-DRP** (line 5 + line 8 +line 15)		2.5	2.7

For notes see Table 14a

Table 14a
Notes to Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP ($M)

Notes:
1 The amounts in line 1 are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for Nuclear Projects - EB-2020-0290 ($M)

Line No.		2023	2024
		(a)	(b)
1a	Forecast Net Plant Rate Base Amount*	14.4	5.6
2a	Weighted Average Cost of Capital**	5.83%	5.90%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)^	0.8	0.3
4a	ROE Component of Forecast Cost of Capital Amount	0.6	0.2
5a	Forecast Depreciation^	8.8	8.8
6a	Forecast Capital Cost Allowance Deduction^	1.9	1.7

* Represents the EB-2020-0290 forecast for the Pickering Extended Operations projects.

** Col. (a) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 12: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (b) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 13: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

^ For lines 5a and 6a, cols. (a) and (b) as shown in EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 3. The sum of the following in cols. (a) and (b) equals $12.1M and $11.6M respectively, per EB-2020-0290 Payment Amounts Order, App. E, p. 9: (i) line 3a; (ii) line 5a; and (iii) the result of the following, multiplied by 25% / (1-25%): line 4a plus line 5a minus line 6a.

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for Nuclear Projects ($M)

Line No.		2023	2024
		(a)	(b)
1b	Gross Plant Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 3b, col. (c))	38.1	121.0
2b	In-service Addition - Darlington Steam Generator Primary Moisture Separators Replacement+	82.2	87.9
2bb	In-service Addition - Pickering Extended Operations	0.6	0.0
3b	Gross Plant Closing Balance (line 1b + line 2b + line 2bb)	121.0	208.9
4b	Gross Plant Rate Base Amount (line 1b + line 3b)/2 ++	93.2	186.9
5b	Accumulated Depreciation Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 7b, col. (c))	18.9	30.5
6b	Depreciation - Darlington Steam Generator Primary Moisture Separators Replacement	2.1	5.1
6bb	Depreciation - Pickering Extended Operations	9.5	4.8
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b + line 6bb)	30.5	40.4
8b	Accumulated Depreciation Rate Base Amount (line 5b + line 7b)/2	24.7	35.4
9b	Net Plant Rate Base Amount (line 4b - line 8b)	68.5	151.5

\+ Col. (a) as shown in Ex. B3-3-1, Table 1a, Note 1 and Ex. D2-1-3, Table 4a, line 13, col. (l). Col. (b) as shown in Ex. B3-3-1 Table 1a, Note 1 and Ex. D2-1-3 Table 4a, line 38, col. (c).

++ In-service additions in 2023 and 2024 for Darlington Steam Generator Primary Moisture Separator exceed $50M, hence the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

3 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to the difference between (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2023 and 2024, and (ii) line 4a, for the corresponding year.

Table 15
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - DRP
Summary of Account Transactions 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k) Total	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Non-Capital Addition to Variance Account:															
1	**Forecast Non-Capital Costs**	1	12.4	5.2	24.2	29.4	13.8	3.5	48.4	19.7	24.2	23.6	29.3		25.0	8.4
2	**Actual Non-Capital Costs**	2	3.1	12.1	24.0	36.1	31.3	1.7	19.0	35.6	22.3	39.0	59.7		10.5	1.8
3	**Non-Capital Addition to Variance Account Before Adjustments** (line 2 - line 1)		(9.3)	6.9	(0.2)	6.7	17.6	(1.8)	(29.4)	15.8	(1.9)	15.4	30.4		(14.5)	(6.6)
4	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment - DRP**	3	1.1	0.4	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
5	**Less: EB-2016-0152 DRP L&ILW Variable Expenses Adjustment**	5	0.0	0.0	2.3	2.3	2.1	3.2	4.6	5.3	0.0	0.0	0.0		0.0	0.0
6	**Less: DRP-Related Impact Recorded in Nuclear Liability Deferral Account**	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	15.7	15.9		1.9	0.3
7	**Non-Capital Addition to Variance Account - DRP** (line 3 - line 4 - line 5 - line 6)		(10.4)	6.4	(2.5)	3.9	15.5	(5.0)	(33.9)	10.6	(6.4)	(0.3)	14.5	(11.5)	(16.4)	(6.9)

Notes:
1 The forecast amounts are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Non-Capital Amounts for the Darlington Refurbishment Program ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals col. (c) 2016	col. (d)/12*5 Jan 1 2017- May 31 2017	col. (g)/12*7 Jun 1 2017 - Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1a	EB-2013-0321 Forecast Costs*	6.6	18.2	12.4	12.4	5.2											
2a	EB-2016-0152 Forecast Costs**						24.2	41.5	13.8	3.5	48.4	19.7					
3a	EB-2020-0290 Forecasts Costs***												24.2	23.6	29.3	25.0	8.4

* Col. (a) from EB-2013-0321, Ex. F2-7-1, Table 1, line 3, col. (e) less EB-2013-0321, Ex. N2-1-1, p. 8, line 2. Col. (b) from EB-2013-0321, Ex. F2-7-1, line 3, col. (f).
** Cols. (g) to (k) from EB-2016-0152, Ex. F2-1-1, line 5, cols. (e) to (i), as per EB-2016-0152 Payment Amounts Order, App. G, p. 10, Note 12.
*** Cols. (l) to (n) from EB-2020-0290 Payment Amounts Order, App. E, p.9.

2 Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. F2-7-1, Table 1, line 4.
Cols. (g) to (k) and cols. (m) and (n) from Ex. F2-7-1, Table 1, line 4 for 2020 to 2024.

3 Col. (a) amount is from EB-2016-0152, Ex. H1-1-1, Table 11a, line 9a and col. (b) is calculated as 5/12 of that value.

4 Reflects the impact on the Darlington Refurbishment Program L&ILW variable expenses recorded in the Nuclear Liability Deferral Account as a result of the 2022 ONFA Reference Plan. This adjustment avoids duplication across the Capacity Refurbishment Variance Account and the Nuclear Liability Deferral Account.

5 Represents a credit adjustment recognized by OPG, in connection with low and intermediate level waste (L&ILW) expenses incurred by the DRP, related to the reference plan amounts against which variances in the DRP non-capital costs were being determined during the period from June 1, 2017 to December 31, 2021 pursuant to the EB-2016-0152 Payment Amounts Order. The adjustment was made to correct an error made by OPG in the draft payment amounts order submission in EB-2016-0152, which was subsequently reproduced in the final EB-2016-0152 Payment Amounts Order. In particular, such reference amounts were based on EB-2016-0152, Ex. F2-7-1, line 4, cols. (e) to (i) of OPG's pre-filed evidence and did not reflect the nuclear liability revenue requirement updates approved by the OEB on account of the 2017 ONFA Reference Plan – as summarized in EB-2016-0152, Ex. J21.2 – which included an increase to the forecast DRP L&ILW expenses. The adjustment is necessary to accurately match the reference amounts to such forecasts included in the OEB-approved revenue requirements and payment amounts in EB-2016-0152. The adjustment has the effect of lowering amounts that would otherwise be recorded as recoverable from customers in the Capacity Refurbishment Variance Account.

Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project
Summary of Account Transactions - 2016, 2017, 2018 , 2019, 2020, 2021, 2022, 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k) Total	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(j)	(k)
	Capital Addition to Variance Account:															
1	**Forecast Cost of Capital Amount**	1	10.3	4.3	23.2		38.2	37.1	301.7	330.5	293.2	280.7	419.7		484.9	524.1
2	**Actual Net Plant Rate Base Amount**	2	340.8	594.6	594.6		693.6	684.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5		8,316.2	9,620.3
3	**Weighted Average Cost of Capital**	1	6.85%	6.85%	6.65%		6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	5.90%		5.92%	5.92%
4	**Actual Cost of Capital Amount**		23.3	17.0	23.1	40.0	45.1	44.2	218.8	336.8	298.0	343.0	413.8		492.3	569.5
5	**Cost of Capital Variance** (line 4 - line 1)		13.1	12.6	(0.2)	12.4	6.9	7.1	(82.9)	6.3	4.8	62.2	(5.9)		7.4	45.4
6	**Forecast Depreciation**	1	4.0	1.7	11.1	12.7	19.2	19.3	148.5	166.9	163.4	163.4	249.8		298.9	334.6
7	**Actual Depreciation**	2	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8		311.4	373.3
8	**Depreciation Variance** (line 7 - line 6)		12.2	8.2	6.6	14.8	14.7	15.1	(25.3)	17.7	21.3	62.7	22.0		12.5	38.7
	Income Tax Impact:															
9	**Forecast Capital Cost Allowance Deduction**	1	66.8	27.8	106.8	134.6	283.7	354.4	380.8	383.2	523.6	550.7	540.3		538.9	520.2
10	**Actual Capital Cost Allowance Deduction**	6	118.7	78.8	104.3	183.1	243.6	412.4	431.6	454.0	489.5	527.3	525.5		540.7	526.5
11	**SR&ED Qualifying Capital Expenditures**		62.4	0.0	20.7	20.7	18.8	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
12	**Difference** (line 9 - line 10 - line 11)		(114.3)	(51.0)	(18.2)	(69.1)	21.3	(58.0)	(50.8)	(70.8)	34.0	23.4	14.8		(1.7)	(6.3)
13	**Net (Decrease) Increase in Regulatory Taxable Income**	3	(94.2)	(35.0)	(11.7)	(46.7)	40.2	(38.5)	(127.0)	(49.3)	58.6	127.7	32.9		15.6	62.3
14	**Income Tax Rate**		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	0.3	25.0%	25.0%	25.0%		0.3	0.3
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		(31.4)	(11.7)	(3.9)	(15.6)	13.4	(12.8)	(42.3)	(16.4)	19.5	42.6	11.0		5.2	20.8
16	**Capital Addition to Variance Account** (line 5 + line 8 + line 15)		(6.2)	9.2	2.5	11.6	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0		25.1	104.8
17	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	5	5.1	2.1		2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
18	**Addition to Variance Account-Capital Portion DRP** (line 16 - line 17)		(11.2)	7.1	2.5	9.5	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0		25.1	104.8
19	**Less: Accelerated Investment Incentive CCA - DRP**	4						(18.9)	(19.9)	3.1						
20	**Total Capital Additon to Variance Account - Capital Portion DRP** (line 18 - line 19)		(11.2)	7.1	2.5	9.5	35.0	28.3	(130.6)	4.4	45.6	167.6	27.0	175.6	25.1	104.8

For notes see Table 16a

Numbers may not add due to rounding.

Table 16a
Notes to Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project

Notes:

1 The amounts in line 1 are determinded as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for the Darlington Refurbishment Program ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals to col. (c) 2016	col. (d) / 12*5 Jan 1 2017- May 31 2017	col. (g) / 12*7 June 1 2017- Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1a	Forecast Net Plant Rate Base Amount*	116.0	184.3					598.1	587.7	572.9	4,685.3	5,140.7	4,978.0	4,815.3	7,114.2	8,191.7	8,853.7
2a	Weighted Average Cost of Capital**	6.86%	6.85%					6.65%	6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	5.90%	5.92%	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	8.0	12.6	10.3	10.3	4.3	23.2	39.8	38.2	37.1	301.7	330.5	293.2	280.7	419.7	484.9	524.1
4a	ROE Component of Forecast Cost of Capital Amount***	4.9	7.7	6.3	6.3	2.6	13.8	23.6	23.2	22.6	185.1	203.1	194.0	187.7	277.2	319.2	345.0
5a	Forecast Depreciation*	3.0	5.0	4.0	4.0	1.7	11.1	19.0	19.2	19.3	148.5	166.9	163.4	163.4	249.8	298.9	334.6
6a	Forecast Capital Cost Allowance Deduction****	39.3	94.3	66.8	66.8	27.8	106.8	183.1	283.7	354.4	380.8	383.2	523.6	550.7	540.3	538.9	520.2

* Cols. (a) and (b) from EB-2013-0321, Ex. L-4.9-1-Staff-048, Chart 1, "Total" line less "Heavy Water & Drum Handling Facility" line.
Cols. (g) to (k) from EB-2016-0152, Ex. L-2.2-1-Staff-009, Attachment 1, "Total" line less "Heavy Water Storage & Drum Handling Facility" line.
Line 1a cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 1, cols. (a) to (e). Line 5a cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 6, cols. (a) to (e).

** Cols. (a) and (b) from EB-2013-0321 Payment Amounts Order, App. A, Tables 5b and 6b: line 6, col. (c).
Cols. (g) to (k) from EB-2016-0152 Payment Amounts Order, App. A, Tables 11 to 15: line 6, col. (c).
Cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. A, Tables 11 to 15: line 4, col. (b) x col. (c), plus line 5a, col. (c) x line 5b, col. (b).

*** The ROE component of the cost of capital forecast is equal to line 1a mulitiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rates as follows: 2016 and Jan 1, 2017 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2026 - 8.66%.

**** Cols. (a) and (b) from EB-2013-0321, Ex. D2-2-1, p. 29, Note 2.
Cols. (g) to (k) from EB-2016-0152, Ex. F4-2-1, Table 3b, Note 3.
Cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 11, cols. (a) to (e).

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for the Darlington Refurbishment Program ($M)

Line No.		2016	Jan 1 2017- May 31 2017	June 1 2017- Dec 31 2017	(b) + (c) Total 2017	2018	2019	2020	2021	2022	2023	2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1b	Gross Plant Opening Balance (col. (a) from EB-2020-0290, Ex. B3-3-1, Table 1, line 2, col. (a))	280.1			444.5	750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5	9,607.1
2b	In-service Addition - Darlington Refurbishment - Unit Refurbishments	0.0			0.0	0.0	0.0	4,765.0	6.2	(2.5)	2,240.1	1,739.6	38.6	2,297.7
3b	In-service Addition - Darlington Refurbishment - Early In-Service	103.4			44.9	22.5	7.6	2.2	1.5	2.9	0.0	0.0	0.0	1.7
4b	In-service Addition - Darlington Refurbishment - Facilities & Infrastructure Projects	43.0			16.9	0.9	0.1	10.0	(1.4)	(0.9)	0.0	0.0	0.0	0.0
5b	In-service Addition - Darlington Refurbishment - Safety Improvement Opportunities	17.9			244.1	11.1	8.2	(3.0)	1.5	4.2	0.0	2.3	0.0	0.0
6b	Total In-Service Additions (line 2b + line 3b + line 4b + line 5b)[+]	164.4	241.0	64.9	305.9	34.5	16.0	4,774.1	7.8	3.7	2,240.1	1,741.9	38.6	2,299.4
7b	Gross Plant Closing Balance (line 1b + line 6b)	444.5			750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5	9,607.1	11,906.5
8b	Gross Plant Rate Base Amount (line 1b + line 7b)/2[++]	362.3			638.0	767.7	792.9	3,585.1	5,579.0	5,584.7	6,614.0	7,993.4	9,587.8	11,234.2
9b	Accumulated Depreciation Opening Balance (col. (a) from EB-2020-0290, Ex. B3-4-1, Table 1, line 2, col. (a))	13.5			29.6	57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9	1,427.3
10b	Depreciation[+]	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8	311.4	373.3
11b	Accumulated Depreciation Closing Balance (line 9b + line 10b)	29.6			57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9	1,427.3	1,800.6
12b	Accumulated Depreciation Rate Base Amount (line 9b + line 11b)/2 [+++]	21.5			43.4	74.1	108.2	187.0	341.0	525.6	731.0	980.0	1,271.6	1,614.0
13b	Net Plant Rate Base Amount (line 8b - line 12b)	340.8			594.6	693.6	684.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5	8,316.2	9,620.3

\+ In-service additions - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. D2-2-9, Table 5a, excluding the D2O Storage Project. Cols. (g) to (m) from Ex. D2-2-3, Table 5a, excluding the D2O Storage Project.
Depreciation - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. F4-1-1, Table 2, line 2, cols. (a) to (d). Cols. (g) to (m) from Ex. F4-1-1, Table 2, line 2, cols. (a) to (g).

++ Total in-service additions include the following amounts over $50M: 2016 - $88.1M for R&FR - Tooling, 2017 - $191.2 for Safety Improvement Opportunities, 2020 - $4,765.0M for Unit 2, 2023 - $2,221.8M for Unit 3, 2024 - $1,689.9M for Unit 1, and 2026 - $2,291.5M for Unit 4. For these in-service additions, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average. Amounts at line 8b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-3-1, Table 1, col. (f), lines 2, 10, 18 and 26. Cols. (g) to (m) from Ex. B3-3-1, Table 1, col. (f), lines 2, 11, 20, 29, 38, 47 and 59.

+++ Amouns at line 12b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-4-1, Table 1, col. (e), lines 2, 10, 18 and 26. Cols. (g) to (k) from Ex. B3-4-1, Table 1, col. (e), lines 2, 11, 20, 29 and 38. Cols. (l) and (m) from Ex. B3-4-1, Table 2, col. (f), lines 2 and 14.

3 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5 . The ROE component of the variance is equal to the difference between: (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the following OEB-approved ROE rates: 2016 and Jan 1 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2026 - 8.66%; and (ii) line 4a, cols. (d) to (f), (h) to (p).

4 Accelerated Investment Incentive CCA is included within the total CCA at line 10, and such amounts for Darlington Refurbishment Program recorded in the Capacity Refuribshment Variance Account have been separately approved for disposition in EB-2020-0290 Payment Amounts Order, Appendix D, Table 1, line 7, col. (f) and EB-2023-0336 Decision and Order, Attachment A, Table 2, line 6, col. (e).

5 Col. (a) amount is from EB-2016-0152 Ex. H1-1-1, Table 11, line 33 and col. (b) is calculated as 5/12 of that value.

6 Amounts are net of impacts to capital cost allowance from the permanent rate base disallowance applied to the D2O Storage Project by the OEB in the EB-2020-0290 Decision and Order.

Table 17
Nuclear Liability Deferral Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2022:					
1	**Depreciation Expense**	1	80.5	80.5	1.1	1.1
	Return on Rate Base					
2	**Average Asset Retirement Costs**	2	151.8	71.2	30.4	29.3
3	**Weighted Average Cost of Capital**	3	5.83%	5.90%	5.92%	5.92%
4	**Return on Rate Base** (line 2 x line 3)		8.8	4.2	1.8	1.7
	Variable Expenses					
5	**Used Fuel Storage and Disposal Variable Expenses**	5	0.3	0.7	1.0	1.5
6	**Low & Intermediate Level Waste Management Variable Expenses**	5	28.8	29.4	12.3	7.9
7	**Total Variable Expenses** (line 5 + line 6)		29.1	30.1	13.3	9.4
	Income Tax Impact					
8	**Forecast Contributions to Segregated Funds**	6	100.6	100.6	0.0	0.0
9	**Contributions to Segregated Funds based on Current Approved ONFA Reference Plan**	7	200.1	200.1	116.4	39.2
10	**Increase in Contributions to Segregated Funds** (line 8 - line 9)		(99.5)	(99.5)	(116.4)	(39.2)
11	**Return on Rate Base - ROE Component** (line 2 x 45% x 8.66%)		5.9	2.8	1.2	1.1
12	**Net Increase in Regulatory Taxable Income** (line 1 + line 7 + line 10 + line 11)		16.1	14.0	(100.8)	(27.6)
13	**Income Tax Rate**		25.0%	25.0%	25.0%	25.0%
14	**Income Tax Impact** (line 12 x line 13 / (1 - line 13))		5.4	4.7	(33.6)	(9.2)
15	**Addition to Deferral Account - Year-End 2021 ARO / ARC Adjustment** (lines 1 + 4 + 7 + 14)		123.9	119.5	(17.4)	3.0
16	**Addition to Deferral Account - Change in Pickering Station End-of-Life Dates (December 31, 2020 End-of-Life Extension)**	4	69.4	67.9	19.6	19.6
17	**Total Addition to Deferral Account** (line 15 + line 16)		193.3	187.5	2.2	22.6

Notes:

1 The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 1 - Change in Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5 - 8	Darlington	(a) + (b) + (c) Total
		(a)	(b)	(c)	(d)
	Incremental Asset Retirement Cost ("ARC") Continuity:				
1a	ARC Adjustment at December 31, 2021 (EB-2023-0336, Ex. H1-1-1, Table 18a, line 7b, cols. (a) to (d))**	254.8	(16.5)	34.2	272.6
2a	Remaining Useful Life as at December 31, 2021 (years)*	3.0	3.0	31.0	
3a	2022 Annual Incremental Depreciation (line 1a / line 2a)	84.9	(5.5)	1.1	80.5
4a	Incremental ARC at December 31, 2022 (EB-2023-0336, Ex. H1-1-1, Table 18, Note 1, line 4a)	169.9	(11.0)	33.1	192.0
5a	Remaining Useful Life as at December 31, 2022 (years)*	2.0	2.0	30.0	
6a	2023 Annual Incremental Depreciation (line 4a / line 5a)	84.9	(5.5)	1.1	80.5
7a	Incremental ARC at December 31, 2023 (line 4a - line 6a)	84.9	(5.5)	32.0	111.5
8a	Remaining Useful Life as at December 31, 2023 (years)*	1.0	1.0	29.0	
9a	2024 Annual Incremental Depreciation (line 7a / line 8a)	84.9	(5.5)	1.1	80.5
10a	Incremental ARC at December 31, 2024 (line 7a - line 9a)	0.0	0.0	30.9	30.9
11a	Remaining Useful Life as at December 31, 2024 (years)*	0.0	0.0	28.0	
12a	2025 Annual Incremental Depreciation (line 10a / line 11a)	0.0	0.0	1.1	1.1
13a	Incremental ARC at December 31, 2025 (line 10a - line 12a)	0.0	0.0	29.8	29.8
14a	Remaining Useful Life as at December 31, 2025 (years)*	0.0	0.0	27.0	
15a	2026 Annual Incremental Depreciation (line 13a / line 14a)	0.0	0.0	1.1	1.1
16a	Incremental ARC at December 31, 2026 (line 13a - line 15a)	0.0	0.0	28.7	28.7

* A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.

** Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 14, cols. (a) through (d), respectively.

2 Col. (a) calculated as (line 4a, col. (d) + line 7a, col. (d)) / 2. Col. (b) calculated as (line 7a, col.(d) + line 10a, col. (d)) / 2. Col. (c) calculated as (line 10a, col.(d) + line 13a, col. (d)) / 2. Col. (d) calculated as (line 13a, col.(d) + line 16a, col. (d)) / 2.

3 Col. (a) WAAC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WAAC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (d) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

4 From Ex. H1-1-1, Table 18, line 22, cols. (a) through (d). Represents the nuclear liabilities component of the revenue requirement impacts arising from the extension of station end-of-life dates for Pickering Units 1 and 4 to December 31, 2024, effective December 31, 2020. As the current approved ONFA Reference Plan reflects this change effective January 1, 2022, this impact is recorded in the Nuclear Liability Deferral Account beginning in 2022. Prior to 2022, the impact was recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account as this change in end-of-life dates was not yet reflected in the current approved ONFA Reference Plan.

5 Values are calculated as the difference between: (A) the product of (i) corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding year in the EB-2020-0290 nuclear revenue requirements, and (B) the product of (i) the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs applicable following the changes in nuclear liabilities as a result of the extension of station end-of-life dates for Pickering Units 1 and 4 effective December 31, 2020, and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding years in the EB-2020-0290 nuclear revenue requirements.

6 Per EB-2020-0290, Ex. C2-1-1, Table 2, line 15, cols. (h) through (k).

7 Cols (a) through (d) from Ex. C2-1-1, Table 2, line 14, cols. (d) through (f), respectively.

Table 18

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension[1]
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Description	Note	Actual 2023	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Cost of Capital					
1	**Asset Retirement Cost ("ARC") Rate Base** (Note 4, line 4h)		2.3	0.6	(0.3)	(0.2)
2	**Non-ARC Rate Base** (Note 5, line 5f)		3.1	1.0	0.0	0.0
3	**Total Return on Rate Base Impact** (line 1 + line 2)		5.5	1.6	(0.3)	(0.2)
	Depreciation Expense:					
4	**Asset Retirement Costs** (Note 2, col. (f))		29.7	29.7	(0.2)	(0.2)
5	**Non-Asset Retirement Costs** (Note 3, line 3c)		38.1	34.6	0.0	0.0
6	**Total Depreciation Expense Impact** (line 4 + line 5)		67.8	64.3	(0.2)	(0.2)
	Other Expenses:					
7	**Used Fuel Storage and Disposal Variable Expenses**	6	19.4	19.9	14.5	14.6
8	**Low & Intermediate Level Waste Management Variable Expenses**	6, 7	0.8	0.8	0.6	0.4
9	**Total Variable Expenses Impact** (line 7 + line 8)		20.2	20.7	15.1	15.1
	Income Taxes:					
10	**Return on Rate Base - Non-ARC Impact - ROE Component** (Note 5, line 5g x (25%/75%))		0.7	0.2	0.0	0.0
11	**Depreciation Expense on Non-Asset Retirement Costs** (line 5 x (25%/75%))		12.7	11.5	0.0	0.0
12	**Total Non-ARC Income Tax Impact** (line 10 + line 11)		13.4	11.8	0.0	0.0
13	**Return on Rate Base - ARC Impact** (Note 4, line 4k x (25%/75%))		0.5	0.1	(0.1)	(0.1)
14	**Depreciation Expense on Asset Retirement Costs** (line 4 x (25%/75%))		9.9	9.9	(0.1)	(0.1)
15	**Used Fuel Storage and Disposal Variable Expenses** (line 7 x (25%/75%))		6.5	6.6	4.8	4.9
16	**Low & Intermediate Level Waste Management Variable Expenses** (line 8 x (25%/75%))		0.3	0.3	0.2	0.1
17	**Total Nuclear Liabilities Income Tax Impact** (line 13 + line 14 + line 15 + line 16)		17.2	16.9	4.9	4.9
18	**Total Income Tax Impact** (line 12 + line 17)		30.5	28.7	4.9	4.9
19	**Revenue Requirement Impact - Nuclear Liabilities** (line 1 + line 4 + line 9 + line 17)		69.4	67.9	19.6	19.6
20	**Revenue Requirement Impact - Non-ARC** (line 2 + line 5 + line 12)		54.6	47.4	0.0	0.0
21	**Total Revenue Requirement Impact** (line 19 + line 20)		124.0	115.4	19.6	19.6
22	**Less: Revenue Requirement Impact Recorded in Nuclear Liability Deferral Account Beginning Jan. 1, 2022** (line 19)	8	69.4	67.9	19.6	19.6
23	**Total Addition to Deferral Account** (line 21 - line 22)		54.6	47.4	0.0	0.0

For notes see Tables 18a and 18b.

Table 18a

Notes to Table 18

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension ($M)

1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p.1. Amounts are as set out in EB-2020-0290 Ex. L-F-01-Staff-271, Att. 1, Table 2, other than those that reflect changes between the EB-2020-0290 proposed and OEB approved revenue requirement for the corresponding year, subject to rounding differences.

2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	(a)+(b)+(c) Total	ARC Depreciation per EB-2020-0290***	(d) - (e) Impact of Year-End 2020 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)
2a	Asset Retirement Cost as at December 31, 2020 Before Pickering Units 1 & 4 End-of-Life Adjustment*	63.3	187.8	113.9	365.2		
2b	Asset Retirement Cost Adjustment as at December 31, 2020 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 7, cols. (a) through (d).)	50.4	5.6	(4.8)	51.1		
2c	Unamortized Asset Retirement Cost as at December 31, 2020 (line 2a + line 2b)	113.6	193.4	109.1	416.2		
2d	Remaining Useful Life as at December 31, 2020 (years)**	4.0	4.0	32.0			
2e	Annual Depreciation (line 2c / line 2d)	28.4	48.3	3.4	80.2	82.2	(2.0)
2f	Unamortized Asset Retirement Cost as at December 31, 2021 (line 2c - line 2e)	85.2	145.0	105.7	336.0		
2g	Remaining Useful Life as at December 31, 2021 (years)**	3.0	3.0	31.0			
2h	2022 Annual Depreciation (line 2f / line 2g)	28.4	48.3	3.4	80.2	82.2	(2.0)
2i	Unamortized Asset Retirement Cost as at December 31, 2022* (line 2f - line 2h)	56.8	96.7	102.3	255.8		
2j	Remaining Useful Life as at December 31, 2022 (years)**	2.0	2.0	30.0			
2k	2023 Annual Depreciation (line 2i / line 2j)	28.4	48.3	3.4	80.2	50.5	29.7
2l	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2i - line 2k)	28.4	48.3	98.9	175.7		
2m	Remaining Useful Life as at December 31, 2023 (years)**	1.0	1.0	29.0			
2n	2024 Annual Depreciation (line 2l / line 2m)	28.4	48.3	3.4	80.2	50.5	29.7
2o	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2l - line 2n)	0.0	0.0	95.5	95.5		
2p	Remaining Useful Life as at December 31, 2024 (years)**	0.0	0.0	28.0			
2q	2025 Annual Depreciation (line 2o / line 2p)	0.0	0.0	3.4	3.4	3.6	(0.2)
2r	Unamortized Asset Retirement Cost as at December 31, 2025 (line 2o - line 2q)	0.0	0.0	92.1	92.1		
2s	Remaining Useful Life as at December 31, 2025 (years)**	0.0	0.0	27.0			
2t	2026 Annual Depreciation (line 2r / line 2s)	0.0	0.0	3.4	3.4	3.6	(0.2)
2u	Unamortized Asset Retirement Cost as at December 31, 2026 (line 2r - line 2t)	0.0	0.0	88.7	88.7		

* From EB-2023-0336, Ex. H1-1-1, Table 19a, line 2a, cols. (a) to (d) (differences due to rounding).

** A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.

*** Per EB-2018-0002 OEB Staff Interrogatory #1, Schedule 1-Staff-1, Att. 1, Table 1a, line 1n, col. (d) for 2021 and EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 8, 17, 26, 35 and 44 for 2023 to 2026, respectively.

3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
3a	Unadjusted Non-ARC Depreciation and Amortization Expense - December 31, 2022 Pickering Units 1 & 4 End-of-Life[+]	421.0	528.2	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 1 & 4 End-of-Life[#]	459.1	562.9	0.4	0.0
3c	Impact of Pickering Units 1 & 4 End-of-Life Extension (line 3b less line 3a)	38.1	34.6	0.0	0.0

\+ EB-2020-0290, Ex. B3-4-1: Table 2, cols. (b) to (d), line 30 for 2023 and line 38 for 2024; Table 3, cols. (b) to (d), line 4 for 2025 and line 12 for 2026.

\# Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2023 to 2026) and holding all other variables constant, effective January 1, 2022 onwards.

4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	215.7	135.6	93.8	90.4
4b	Average UNL[++++]	(107.0)	(290.8)	(452.1)	(547.2)
4c	Weighted Average Accretion Rate[+]	4.86%	4.86%	4.86%	4.86%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)[++]	0.0	0.0	0.0	0.0
4e	Return on Rate Base at Weighted Average Cost of Capital (line 4a x WACC, as line 4b < 0)[+++]	12.6	8.0	5.6	5.4
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate^	0.0	0.0	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital^^	10.2	7.4	5.8	5.6
4h	Impact of Pickering Units 1 & 4 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g))	2.3	0.6	(0.3)	(0.2)
4i	ROE Component of Line 4e Cost of Capital ((line 4a x 45% x 8.66%), as line 4b < 0)	8.4	5.3	3.7	3.5
4j	ROE Component of Line 4g Cost of Capital^^^	6.8	4.9	3.8	3.7
4k	Impact of Pickering Units 1 & 4 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4i - line 4j))	1.6	0.4	(0.2)	(0.2)

\+ From EB-2020-0290, Ex. L-A1-2-Staff-002, Att. 1, Table 5, line 7, col. (c).

\++ When UNL is a negative value, no return on rate base at weighted average accretion is recorded and the return at rate base is limited to average ARC at line 4a multiplied by the OEB-approved weighted average cost of capital (WACC), as shown in line 4e.

\+++ Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (d) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

\++++ From EB-2020-0290, Ex. L-F-01-Staff-271, Att. 1, Table 2b, line 4b, cols. (b)-(e) for the corresponding years.

^ EB-2020-0290 Payment Amounts Order, App. A: Table 12, line 7, col. (d) for 2023, Table 13, line 7, col. (d) for 2024, Table 14, line 7, col. (d) for 2025 and Table 15, line 7, col. (d) for 2026.

^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) multiplied by WACC (see note +++).
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) multiplied by WACC (see note +++).
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) multiplied by WACC (see note +++).
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) multiplied by WACC (see note +++).

^^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.

Table 18b

Notes to Table 18 - Continued

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension ($M)

5 Cost of Capital for Non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
5a	Opening Non-ARC Net Plant Balance Impact##	72.7	34.6	0.0	0.0
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	(38.1)	(34.6)	0.0	0.0
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	34.6	0.0	0.0	0.0
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	53.7	17.3	0.0	0.0
5e	Weighted Average Cost of Capital###	5.83%	5.90%	5.92%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	3.1	1.0	0.0	0.0
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	2.1	0.7	0.0	0.0

Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 19b, line 5c., col. (b).

See Ex. H1-1-1, Table 18a, Note +++.

6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirements for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 2.01% discount rate used to determine the year-end 2020 ARO adjustment reflecting the Pickering Units 1 and 4 end-of-life extension, and (ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses included in the EB-2020-0290 nuclear revenue requirements.

7 Actual 2023 and 2024 amounts exclude $1.3M and $1.1M of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2025 and 2026 amounts of $0.4M and $0.1M, respectively, are excluded for the same reason.

8 Refer to Ex. H1-1-1, Table 17, Note 4.

Table 19

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension[1]

Summary of Account Transactions - 2024 ($M)

Line No.	Description	Note	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)
	Cost of Capital:				
1	**Asset Retirement Cost ("ARC") Rate Base** (Note 4, line 4j)		18.5	17.4	17.1
2	**Non-ARC Rate Base** (Note 5, line 5f)		1.9	3.6	3.1
3	**Total Return on Rate Base Impact** (line 1 + line 2)		20.5	21.0	20.2
	Depreciation Expense:				
4	**Asset Retirement Costs** (Note 2, col. (h))		78.1	6.8	6.8
5	**Non-Asset Retirement Costs** (Note 3, line 3c)		(65.5)	8.9	8.7
6	**Total Depreciation Expense Impact** (line 4 + line 5)		12.6	15.7	15.6
	Other Expenses:				
7	**Used Fuel Storage and Disposal Variable Expenses**	6	(29.9)	(21.9)	(21.8)
8	**Low & Intermediate Level Waste Management Variable Expenses**	6,7	(5.8)	(4.4)	(3.1)
9	**Total Variable Expenses Impact** (line 7 + line 8)		(35.7)	(26.2)	(24.9)
	Income Taxes:				
10	**Return on Rate Base - Non-ARC Impact - ROE Component** (Note 5, line 5g x (25%/75%))		0.4	0.8	0.7
11	**Depreciation Expense on Non-Asset Retirement Costs** (line 5 x (25%/75%))		(21.8)	3.0	2.9
12	**Total Non-ARC Income Tax Impact** (line 10 + line 11)		(21.4)	3.7	3.6
13	**Return on Rate Base - ARC Impact** (Note 4, line 4o x (25%/75%))		7.6	6.6	6.5
14	**Depreciation Expense on Asset Retirement Costs** (line 4 x (25%/75%))		26.0	2.3	2.3
15	**Used Fuel Storage and Disposal Variable Expenses** (line 7 x (25%/75%))		(10.0)	(7.3)	(7.3)
16	**Low & Intermediate Level Waste Management Variable Expenses** (line 8 x (25%/75%))		(1.9)	(1.5)	(1.0)
17	**Total Nuclear Liabilities Income Tax Impact** (line 13 + line 14 + line 15 + line 16)		21.7	0.2	0.5
18	**Total Income Tax Impact** (line 12 + line 17)		0.3	3.9	4.1
19	**Revenue Requirement Impact - Nuclear Liabiilties** (line 1 + line 4 + line 9 + line 17)		82.6	(1.9)	(0.4)
20	**Revenue Requirement Impact - Non-ARC** (line 2 + line 5 + line 12)		(84.9)	16.2	15.4
21	**Total Addition to Deferral Account** (line 19 + line 20)		(2.3)	14.4	15.0

For notes see Tables 19a and 19b.

Table 19a
Notes to Table 19
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension ($M)

1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p.1.
2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	(a)+(b)+(c) Total	ARC Depreciation per EB-2020-0290 *	Impact of Year-End 2020 Adjustment**	Impact of 2022 ONFA Reference Plan (Year-End 2021) Adjustment***	(d) - (e) - (f) - (g) Impact of Year-End 2023 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2a	Asset Retirement Cost as at December 31, 2023 Before Pickering Units 5-8 End-of-Life Adjustment (Col. (d) from Ex. C2-1-1, Table 2, line 23, col. (d).)	113.1	42.7	130.9	286.7				
2b	Asset Retirement Cost Adjustment as at December 31, 2023 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 22, cols. (a) through (d).)	114.3	490.7	(130.9)	474.1				
2c	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2a + line 2b)	227.4	533.4	0.0	760.8				
2d	Remaining Useful Life as at December 31, 2023 (years) #	1.0	47.0	29.0					
2e	2024 Annual Depreciation (line 2c / line 2d) (Col. (d) from Ex. C2-1-1, Table 2, line 22, col. (e) and from Ex. F4-1-1, Table 2, line 9, col. (e).)	227.4	11.3	0.0	238.8	50.5	29.7	80.5	78.1
2f	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2c - line 2e)	0.0	522.0	0.0	522.0				
2g	Remaining Useful Life as at December 31, 2024 (years) #	0.0	46.0	28.0					
2h	2025 Annual Depreciation (line 2f / line 2g)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2i	Unamortized 2025 Asset Retirement Cost as at December 31, 2025 (line 2f - line 2h)	0.0	510.7	0.0	510.7				
2j	Remaining Useful Life as at December 31, 2025 (years) #	0.0	45.0	27.0					
2k	2026 Annual Depreciation (line 2i / line 2j)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2l	Unamortized 2026 Asset Retirement Cost as at December 31, 2026 (line 2i - line 2k)	0.0	499.3	0.0	499.3				

* Per EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 26, 35 and 44 for 2024 to 2026, respectively.
** From Ex. H1-1-1, Table 18, line 4, cols. (b) through (d) for 2024 to 2026, respectively.
*** Ex. H1-1-1, Table 17, line 1, cols. (b) through (d) for 2024 to 2026, respectively.
\# A common end of life date of December 31, 2024 is used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations. An end of life date of December 31, 2070 is used to depreciate ARC for Pickering Units 5-8.

3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
3a	Unadjusted non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 5-8 End of Life+	562.9	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2070 Pickering Units 5-8 End-of Life++	497.4	9.2	8.7
3c	Impact of Pickering End-of-Life Extension (line 3b less line 3a)	(65.5)	8.9	8.7

\+ Cols. (a) through (c) from Ex. H1-1-1, Table 18a, line 3b, cols. (b) through (d), respectively.
\++ Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2024-2026) and holding all other variables constant, effective January 1, 2022.

Table 19b

Notes to Table 19 - Continued

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account (December 31, 2023 End-of-Life Extension) ($M)

4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	641.4	516.4	505.0
4b	Average UNL	774.0	640.3	567.0
4c	Weighted Average Accretion Rate (Ex. C1-1-1, Table 9, line 7, col. (c))	4.79%	4.79%	4.79%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)	30.7	24.7	24.2
4e	Return on Rate Base at Weighted Average Cost of Capital ((line 4a - line 4b) x WACC), if line 4a > line 4b)#	0.0	0.0	0.0
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate (from Ex. H1-1-1, Table 18a, line 4f)	0.0	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital (from Ex. H1-1-1, Table 18a, line 4g)	7.4	5.8	5.6
4h	Impact of Year-End 2020 ARO Adjustment (from Ex. H1-1-1, Table 18a, line 4h, cols. (b) to (d))	0.6	(0.3)	(0.2)
4i	Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment (from Ex. H1-1-1, Table 17, line 4, cold. (b) to (d))	4.2	1.8	1.7
4j	Impact of Pickering Units 5-8 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g) - (line 4h + line 4i))	18.5	17.4	17.1
4k	ROE Component of Line 4e Cost of Capital (((line 4a-4b) x 45% x 8.66%), if line 4a > line 4b)	0.0	0.0	0.0
4l	ROE Component of Line 4g Cost of Capital (from Ex. H1-1-1, Table 18a, line 4j, cols. (b) to (d))	4.9	3.8	3.7
4m	ROE Component of Impact of Year-End 2020 ARO Adjustment (from Ex. H1-1-1, Table 18a, line 4k, cols. (b) to (d))	0.4	(0.2)	(0.2)
4n	ROE Component of Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment^	2.8	1.2	1.1
4o	Impact of Pickering Units 5-8 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4k - line 4l) - line 4m - line 4n)	22.7	19.9	19.5

\# Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

^ Col. (a) Ex. H1-1-1, Table 17, line 2, col. (b) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (b) Ex. H1-1-1, Table 17, line 2, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (c) Ex. H1-1-1, Table 17, line 2, col. (d) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.

5 Cost of Capital for non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
5a	Opening Non-ARC Net Plant Balance Impact	0.0	65.5	56.6
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	65.5	(8.9)	(8.7)
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	65.5	56.6	47.9
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	32.7	61.0	52.2
5e	Weighted Average Cost of Capital+	5.90%	5.92%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	1.9	3.6	3.1
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	1.3	2.4	2.0

\+ For calculation of WACC, see note ##

6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirement for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 3.93% discount rate used to determine the year-end 2023 ARO adjustment reflecting the Pickering Units 5-8 end-of-life extension, and(ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses reflecting the 2.45% discount rate used to record variable expenses during 2022 and 2023, following the year-end 2021 ARO adjustment reflecting the impact of the 2022 ONFA Reference Plan.

7 Actual 2024 amount excludes $7.5M of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2025 and 2026 amounts of $1.7M and $0.2M, respectively, are excluded for the same reason.

Table 20
Nuclear Development Variance Account - Darlington New Nuclear Program
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
	Income Tax Impact:			
1	**Forecast Capital Cost Allowance Deduction**		0.0	0.0
2	**Actual Capital Cost Allowance Deduction**		0.0	23.9
3	**Actual SR&ED Qualifying Expenditures**		21.1	56.0
4	**Difference** (line 1 - line 2 - line 3)		(21.1)	(79.9)
5	**Net Decrease in Regulatory Taxable Income** (line 4)		(21.1)	(79.9)
6	**Income Tax Rate**		25%	25%
7	**Income Tax Impact** (line 5 x line 6 / (1 - line 6))		(7.0)	(26.6)
8	**Capital Addition to Variance Account** (line 7)		(7.0)	(26.6)
	Non-Capital Addition to Variance Account:			
9	**Forecast Costs**	2	2.2	2.3
10	**Actual Costs**	3	1.1	2.3
11	**Difference** (line 10 - line 9)		(1.1)	0.1
12	**Non-Capital Addition to Variance Account** (line 11)		(1.1)	0.1
13	**Total Addition to Variance Account** (line 8 + line 12)		(8.1)	(26.5)

Notes:

1 From EB-2020-0290 Payment Amounts Order, App. E, p.16.

2 From Ex. F2-1-1, Table 1a, line 8, cols. (d) and (e).

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes the proposed approach for clearing the audited December 31, 2024 balances in OPG's deferral and variance accounts ("D&V accounts").

2.0 SUMMARY

OPG is requesting recovery of the audited December 31, 2024 balances in the D&V accounts, less amortization amounts previously approved by the OEB in EB-2020-0290 (for 2025-2026) and EB-2023-0336 (for 2025-2026), together with the income tax impacts associated with the recovery of the Pension & Other Post-Employment Benefits ("OPEB") Cash Versus Accrual Differential Deferral Account,[1] through payment amount riders effective from January 1, 2027-December 31, 2031. As outlined in Ex. H1-1-1, OPG is not seeking clearance of balances in the following accounts: the hydroelectric components of the Capacity Refurbishment Variance Account, the components of the Nuclear Development Variance Account not related to the Darlington New Nuclear Program ("DNNP"), and the Pickering B Variance Account. Audited balances at December 31, 2024 are presented at Ex. H1-1-1, Table 1, and discussed at Ex. H1-1-1.

Section 3.0 describes the methodology for the proposed recovery of the balances in the D&V accounts and the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Section 4.0 describes the proposed recovery periods for the regulated hydroelectric and nuclear D&V account balances. Section 5.0 describes the payment riders proposed for the recovery of these balances.

3.0 METHODOLOGY

The Application proposes to calculate separate hydroelectric and nuclear payment riders for the period from January 1, 2027-December 31, 2031 in the form of $/MWh rates consistent

[1] The recovery or repayment of the income tax impacts associated with the recovery or repayment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account is consistent with the approach reflected in EB-2020-0290 and EB-2023-0336. Further details can be found in EB-2020-0290 (Ex. H1-2-1) and EB-2018-0243 (Ex. F1-1-1).

with the form of payment riders approved in decisions and payment amounts orders in prior OPG proceedings.

The approach that has been used to calculate the proposed hydroelectric and nuclear payment riders is consistent with the methodology previously approved by the OEB.[2] Under this approach, each rider is calculated separately using the following three steps. First, a recovery or repayment period is determined for each account to be cleared. Second, based on each account's recovery or repayment period and the audited balance in the account less any amortization already approved, the amount to be amortized in each year of the period is determined. Finally, the total amount to be amortized each year for all balances is divided by a forecast of annual energy production volumes to determine the payment riders in each year.

OPG proposes to calculate the hydroelectric payment amount rider using the 2027 hydroelectric production forecast approved in this application. Consistent with direction in O. Reg. 53/05, s. 14(2)7, OPG proposes to calculate the nuclear payment amount rider according to the following formula: (E + F) / (C+D), where

> "E" is the sum of the balances proposed for clearance in deferral and variance accounts for OPG's regulated nuclear facilities,
> "F" is the sum of the balances proposed for clearance in deferral and variance accounts for the DNNP facilities,[3]
> "C" is the OEB-approved production forecast for OPG's regulated nuclear facilities,
> "D" is the OEB-approved production forecast for the DNNP facilities.

Any differences between the production amounts used to set the payment amount riders and actual production will continue to be addressed by entries into the Hydroelectric Deferral and

[2] The approach for calculating the nuclear payment rider is also consistent with direction in O. Reg. 53/05, s. 14(2)7.
[3] The amount in "F" is equal to zero as the Application is not proposing clearance of any deferral and variance accounts for the DNNP facilities.

Variance Over/Under Recovery Variance Account and Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG).

4.0 RECOVERY PERIODS

With the exception of the Rate Smoothing Deferral Account, OPG proposes to recover the D&V account balances on a straight-line basis, over the three-year period from January 1, 2027-December 31, 2029. As discussed below, OPG proposes to recover the Rate Smoothing Deferral Account on a straight-line basis over the ten-year period from January 1, 2027-December 31, 2036.

A three-year recovery or repayment period for the majority of the D&V account balances in this Application is consistent with the recovery or repayment periods for the majority of D&V account balances approved in prior OPG proceedings.[4] The Application proposes the maximum permissible period for recovery of the Rate Smoothing Deferral Account due to its larger size, which will help to mitigate customer bill impacts.

As discussed in Ex. H1-1-1, Section 5.18, Section 6(2)12(iv) of O. Reg. 53/05 stipulates that OPG is to recover the balance recorded in the Rate Smoothing Deferral Account on a straight-line basis over a period not to exceed ten years commencing when the Darlington Refurbishment Program ends. With the Darlington Refurbishment Program expected to be completed during 2026, OPG proposes to recover the balance in this account as of December 31, 2024 over the ten-year period permitted beginning January 1, 2027 such that balances in the account can be recovered in their entirety prior to the ten year period ending December 31, 2036.

5.0 PAYMENT RIDERS

The calculation of the Hydroelectric Payment Rider is shown in Ex. H1-2-1, Table 1, while the Nuclear Payment Rider calculation is shown in Ex. H1-2-1, Table 2. In both tables, the 2024 audited D&V account balances (col. a) less the 2025-2026 amortization approved in EB-2020-

[4] For example: EB 2023-0336 – majority of balances cleared over a 30 month period. EB-2020-0290 – majority of balances cleared over 36 month period. EB-2018-0243 – majority of balances cleared over 36 month period.

0290 (col. b) and EB 2023-0336 (col. c) results in the balance available for recovery or repayment (col. d). Amounts proposed to be deferred to future applications are removed from this balance (col. e), resulting in the amounts proposed for recovery or repayment in this application (col. f). The proposed recovery or repayment terms described in Section 4.0 (col. g) are used to determine the amount to be amortized in each year of the 2027-2031 period for which D&V account riders are proposed, as discussed in Section 3.0. Remaining unamortized balances as at December 31, 2031 are also provided (col. n) to illustrate full disposition of balances available for recovery or repayment.

The proposed Hydroelectric Payment Rider is calculated using the amounts available for recovery or repayment in each year, comprising the total of hydroelectric D&V account amortizations in the year and the income tax impacts associated with the recovery of the hydroelectric component of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, divided by the proposed production forecast for the hydroelectric facilities, as set out in Section 3.0. The resulting rider in effect would be a repayment of $1.17/MWh in 2027, 2028, and 2029.

The proposed Nuclear Payment Rider is calculated using the amounts available for recovery or repayment in each year comprising the total of nuclear D&V account amortizations in the year, divided by the proposed production forecast for the combined OPG nuclear facilities and the DNNP facilities, as set out in Section 3.0. The resulting riders in effect would be $7.19/MWh in 2027, $5.04/MWh in 2028, $5.36/MWh in 2029, $2.48/MWh in 2030, and $2.19/MWh in 2031.

Table 1
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Note	Audited Year End Balance 2024	EB-2020-0290 OEB-Approved Amortization (2025-2026)	EB-2023-0336 OEB-Approved Amortization (2025-2026)	(a)-(b)-(c) 2024 Balance Less Approved Amortization	Amounts Deferred to Future Applications	(d)-(e) Amounts Recoverable (Refundable) in Current Application	Disposition Period (months)	Amortization Jan - Dec 2027	Amortization Jan - Dec 2028	Amortization Jan - Dec 2029	Amortization Jan - Dec 2030	Amortization Jan - Dec 2031	(h)+(i)+(j)+(k)+(l) Amortization	(d)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3											
1	**Hydroelectric Water Conditions Variance**		(172.6)	0.0	(79.7)	(92.9)	0.0	(92.9)	36	(31.0)	(31.0)	(31.0)	0.0	0.0	(92.9)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(22.2)	0.0	(9.7)	(12.5)	0.0	(12.5)	36	(4.2)	(4.2)	(4.2)	0.0	0.0	(12.5)	0.0
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		305.6	0.0	231.7	73.9	0.0	73.9	36	24.6	24.6	24.6	0.0	0.0	73.9	0.0
5	**Income and Other Taxes Variance - Hydroelectric**		(17.3)	0.0	(9.2)	(8.1)	0.0	(8.1)	36	(2.7)	(2.7)	(2.7)	0.0	0.0	(8.1)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**	4	162.1	0.0	41.4	120.7	120.7	0.0		0.0	0.0	0.0	0.0	0.0	0.0	120.7
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account**		8.6	0.0	4.4	4.2	0.0	4.2	36	1.4	1.4	1.4	0.0	0.0	4.2	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		0.0	0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		16.5	16.5	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		0.0	0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		17.7	17.7	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		(8.0)	0.0	22.5	(30.5)	0.0	(30.5)	36	(10.2)	(10.2)	(10.2)	0.0	0.0	(30.5)	0.0
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(76.3)	0.0	(41.0)	(35.2)	0.0	(35.2)	36	(11.7)	(11.7)	(11.7)	0.0	0.0	(35.2)	0.0
14	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**		(8.5)	0.0	(1.6)	(6.9)	0.0	(6.9)	36	(2.3)	(2.3)	(2.3)	0.0	0.0	(6.9)	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.7	0.0	11.0	5.6	0.0	5.6	36	1.9	1.9	1.9	0.0	0.0	5.6	0.0
16	**Total**		222.3	34.2	169.8	18.3	120.7	(102.4)		(34.1)	(34.1)	(34.1)	0.0	0.0	(102.4)	120.7
17	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**	5				(10.2)	0.0	(10.2)	36	(3.4)	(3.4)	(3.4)	0.0	0.0	(10.2)	0.0
18	**Sale of Unprescribed Kipling Site Deferral**	6	(6.3)	0.0	(5.1)	(1.2)	0.0	(1.2)	36	(0.4)	(0.4)	(0.4)	0.0	0.0	(1.2)	0.0
19	**Total Recoverable (Refundable) Amount**					6.9	120.7	(113.8)		(37.9)	(37.9)	(37.9)	0.0	0.0	(113.8)	120.7
20	**Forecast Production (TWh)**	7								32.5	32.5	32.5				
21	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 19 / line 20)									(1.17)	(1.17)	(1.17)				

Notes:
1 From Ex. H1-1-1 Table 1, col (c).
2 From EB-2020-0290 Payments Amounts Order, App. C, Table 1, sum of cols. (k), (l).
3 From EB-2023-0336 Decision and Order, App. A, Table 1, sum of cols. (h), (i).
4 Clearance of the balance is proposed to be deferred to a future application.
5 Calculated as: line 12 * tax rate / (1 - tax rate). Tax rate from Ex. F4-2-1, Table 3b, line 27.
6 The balance is split evenly across Regulated Hydroelectric and Nuclear, consistent with the OEB-approved settlement proposal in EB-2023-0336 (EB-2023-0336 Decision and Order, June 13, 2024, App. B, p. 17).
7 From Ex. E1-1-1, Table 1, line 4, col. (l).

Numbers may not add due to rounding.

Table 2
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Note	Audited Year End Balance 2024	EB-2020-0290 OEB-Approved Amortization (2025-2026)	EB-2023-0336 OEB-Approved Amortization (2025-2026)	(a)-(b)-(c) 2024 Balance Less Approved Amortization	Amounts Deferred to Future Applications	(d)-(e) Amounts Recoverable (Refundable) in Current Application	Disposition Period (months)	Amortization Jan - Dec 2027	Amortization Jan - Dec 2028	Amortization Jan - Dec 2029	Amortization Jan - Dec 2030	Amortization Jan - Dec 2031	(h)+(i)+(j)+(k)+(l) Amortization	(d)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3											
1	**Nuclear Liability Deferral**		527.3	0.0	150.7	376.6	0.0	376.6	36	125.5	125.5	125.5	0.0	0.0	376.6	0.0
2	**Nuclear Development Variance - DNNP**		61.8	0.0	86.6	(24.9)	0.0	(24.9)	36	(8.3)	(8.3)	(8.3)	0.0	0.0	(24.9)	0.0
3	**Nuclear Development Variance - Non DNNP**	4	23.5	0.0	0.0	23.5	23.5	0.0		0.0	0.0	0.0	0.0	0.0	0.0	23.5
4	**Ancillary Services Net Revenue Variance - Nuclear**		(13.5)	0.0	(9.0)	(4.5)	0.0	(4.5)	36	(1.5)	(1.5)	(1.5)	0.0	0.0	(4.5)	0.0
5	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**		170.2	0.0	0.0	170.2	0.0	170.2	36	56.7	56.7	56.7	0.0	0.0	170.2	0.0
6	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		173.7	0.0	89.4	84.3	0.0	84.3	36	28.1	28.1	28.1	0.0	0.0	84.3	0.0
7	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(16.8)	0.0	(14.5)	(2.3)	0.0	(2.3)	36	(0.8)	(0.8)	(0.8)	0.0	0.0	(2.3)	0.0
8	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		70.1	0.0	63.5	6.7	0.0	6.7	36	2.2	2.2	2.2	0.0	0.0	6.7	0.0
9	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		42.1	42.1	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Bruce Lease Net Revenues Variance - Post-2017 Additions**		(102.0)	0.0	1.4	(103.4)	0.0	(103.4)	36	(34.5)	(34.5)	(34.5)	0.0	0.0	(103.4)	0.0
11	**Income and Other Taxes Variance - Nuclear**		(9.5)	0.0	(7.3)	(2.1)	0.0	(2.1)	36	(0.7)	(0.7)	(0.7)	0.0	0.0	(2.1)	0.0
12	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		0.0	0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(411.1)	0.0	(98.0)	(313.1)	0.0	(313.1)	36	(104.4)	(104.4)	(104.4)	0.0	0.0	(313.1)	0.0
14	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		106.4	106.4	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		0.0	0.0	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		111.3	111.3	0.0	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		131.9	0.0	131.9	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(244.4)	0.0	(213.8)	(30.6)	0.0	(30.6)	36	(10.2)	(10.2)	(10.2)	0.0	0.0	(30.6)	0.0
19	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**		(42.1)	0.0	(9.5)	(32.6)	0.0	(32.6)	36	(10.9)	(10.9)	(10.9)	0.0	0.0	(32.6)	0.0
20	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(61.5)	0.0	(46.4)	(15.1)	0.0	(15.1)	36	(5.0)	(5.0)	(5.0)	0.0	0.0	(15.1)	0.0
21	**Fitness for Duty Deferral**		2.5	0.0	0.0	2.5	0.0	2.5	36	0.8	0.8	0.8	0.0	0.0	2.5	0.0
22	**SR&ED ITC Variance**		(25.7)	0.0	(0.4)	(25.2)	0.0	(25.2)	36	(8.4)	(8.4)	(8.4)	0.0	0.0	(25.2)	0.0
23	**Rate Smoothing Deferral**		677.4	0.0	0.0	677.4	0.0	677.4	120	67.7	67.7	67.7	67.7	67.7	338.7	338.7
24	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		85.1	0.0	85.1	0.0	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		66.1	0.0	(36.0)	102.1	0.0	102.1	36	34.0	34.0	34.0	0.0	0.0	102.1	0.0
26	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		(2.3)	0.0	0.0	(2.3)	0.0	(2.3)	36	(0.8)	(0.8)	(0.8)	0.0	0.0	(2.3)	0.0
27	**Pickering Closure Costs Deferral**		7.6	0.0	0.0	7.6	0.0	7.6	36	2.5	2.5	2.5	0.0	0.0	7.6	0.0
28	**Clarington Corporate Campus Deferral**		7.7	0.0	0.0	7.7	0.0	7.7	36	2.6	2.6	2.6	0.0	0.0	7.7	0.0
29	**Pickering B Variance**	4	131.1	0.0	0.0	131.1	131.1	0.0		0.0	0.0	0.0	0.0	0.0	0.0	131.1
30	**Total**		1,466.8	259.8	173.6	1,033.4	154.6	878.8		134.9	134.9	134.9	67.7	67.7	540.1	493.3
31	**Sale of Unprescribed Kipling Site Deferral**	5	(6.3)	0.0	(5.1)	(1.2)	0.0	(1.2)	36	(0.4)	(0.4)	(0.4)	0.0	0.0	(1.2)	0.0
32	**Total Recoverable (Refundable) Amount**					1,032.2	154.6	877.6		134.5	134.5	134.5	67.7	67.7	538.9	493.3
33	**Forecast Production (TWh)**	6								18.7	26.7	25.1	27.3	30.9		
34	**Nuclear Payment Rider ($/MWh)** (line 32 / line 33)									7.19	5.04	5.36	2.48	2.19		

Notes:
1 From Ex. H1-1-1 Table 1, col (c).
2 From EB-2020-0290 Payments Amounts Order, App. D, Table 1, sum of cols. (k), (l).
3 From EB-2023-0336 Decision and Order, App. A, Table 2, sum of cols. (h), (i).
4 Clearance of the balance is proposed to be deferred to a future application.
5 The balance is split evenly across Regulated Hydroelectric and Nuclear, consistent with the OEB-approved settlement proposal in EB-2023-0336 (EB-2023-0336 Decision and Order, June 13, 2024, App. B, p. 17).
6 From Ex. E2-1-1, Table 1, cols. (h) to (l), line 5.

SUMMARY OF REVENUE REQUIREMENT AND REVENUE DEFICIENCY

1.0 PURPOSE

This evidence provides a summary of the 2027-2031 revenue requirements for:

- OPG's nuclear facilities;
- OPG's regulated hydroelectric facilities; and
- DNNP LP's facility.

This evidence also includes the revenue deficiency amounts for the same period for OPG's nuclear and regulated hydroelectric facilities.

2.0 REVENUE REQUIREMENT

For OPG's regulated hydroelectric facilities, this Application is seeking approval of a proposed 2027 revenue requirement of $1,668.3M, as presented in Ex. I1-1-1, Table 1.

For OPG's nuclear facilities, this Application is seeking approval of proposed revenue requirements, net of the stretch factor, of $4,062.8M for 2027, $4,257.4M for 2028, $4,677.0M for 2029, $4,882.4M for 2030, and $5,737.6M for 2031, as presented in Ex. I1-1-1, Table 2.

For the DNNP facilities, this Application is seeking approval of proposed revenue requirements of $301.0M for 2027, $378.8M for 2028, $404.9M for 2029, $559.3M for 2030, and $1,042.0M for 2031, as presented in Ex. I1-1-1, Table 2a.

The revenue requirement amounts above do not include the recovery of deferral and variance account balances. OPG is seeking to clear certain deferral and variance accounts using a hydroelectric payment rider and a nuclear payment rider as discussed in Ex. H1-2-1.

3.0 REVENUE DEFICIENCY

Exhibit I1-1-1, Table 3a compares:

a) OPG's forecast revenues determined using the 2026 regulated hydroelectric payment amount set in EB-2020-0290 (i.e., 2026 regulated hydroelectric payment amount multiplied by the regulated hydroelectric production forecast for 2027 proposed in this Application); and
b) the regulated hydroelectric revenue requirement for 2027 proposed in this Application.

OPG's revenue deficiency for the regulated hydroelectric facilities is $243.9M for 2027.

Exhibit I1-1-1, Table 3b compares:

a) Forecast revenues determined using the 2026 nuclear payment amount approved in EB-2020-0290 (i.e., 2026 nuclear payment amount multiplied by the production forecast for 2027-2031 for the OPG nuclear facilities); and
b) the OPG nuclear revenue requirements net of stretch factor proposed in this Application.

The revenue deficiency for the nuclear facilities is $1,981.8M for 2027, $1,285.8M for 2028, $1,886.3M for 2029, $1,896.1M for 2030, and $2,515.3M for 2031.

Exhibit I1-1-1, Tables 4 and 5 present the determination of OPG's 2025 and 2026 forecast regulated return on equity ("ROE") at current payment amounts. Chart 1 below provides these forecast ROE for 2025 and 2026, along with the actual ROE for 2022-2024 as well as the expected average ROE for the 2022-2026 period.

Chart 1 - Actual and Forecast ROE

	2022	**2023**	**2024**	**2025**	**2026**	**Average**
OPG ROE	12.4%	13.7%	5.9%	12.5%	5.6%	10.0%
OEB-approved[1]	8.97%	8.97%	8.93%	8.92%	8.91%	8.94%

[1] OEB-approved is a rate-base-weighted average of the 8.66% ROE approved for the nuclear business in EB-2020-0290 and 9.33% ROE approved for the hydroelectric business in EB-2013-0321.

4.0 REVENUE REQUIREMENT WORK FORM

A Revenue Requirement Work Form ("RRWF") is attached as Attachment 1 to this exhibit and has also been filed in MS Excel worksheet format. The OEB provides a proprietary RRWF model as a filing requirement for transmission and distribution applications, intended to support the calculation of revenue deficiency or sufficiency. The Application includes a RRWF customized to OPG and DNNP LP's circumstances in order to provide a mechanism to support the Application for 2027-2031 payment amounts for the prescribed nuclear facilities and the 2027 payment amount for the prescribed hydroelectric facilities. This is consistent with the approach taken in EB-2020-0290.

Similar to the OEB RRWF, adjustments are entered in a single worksheet with the effect of these adjustments presented in subsequent worksheets.

LIST OF ATTACHMENTS

Attachment 1: Revenue Requirement Work Form

Numbers may not add due to rounding.

Table 1
Summary of Revenue Requirement - Regulated Hydroelectric ($M)
Year Ending December 31, 2027

Line No.	Description	Note	2027
			(a)
	Rate Base		
1	**Net Fixed Assets**	1	9,115.6
2	**Working Capital**	1	0.3
3	**Cash Working Capital**	1	19.3
4	**Total Rate Base**		9,135.1
	Capitalization		
5	**Short-Term Debt**	2	152.4
6	**Long-Term Debt**	2	4,232.4
7	**Common Equity**	2	4,750.3
8	**Total Capital**		9,135.1
	Cost of Capital		
9	**Short-Term Debt**	3	7.7
10	**Long-Term Debt**	3	193.8
11	**Common Equity**	3	432.8
12	**Total Cost of Capital**		634.2
	Expenses:		
13	**OM&A**	4	499.3
14	**GRC**	5	352.2
15	**Depreciation & Amortization**	6	215.4
16	**Property Tax**	7	2.1
17	**Total Expenses**		1,069.0
	Less:		
	Other Revenues		
18	**Ancillary and Other Revenue**	8	62.2
19	**Total Other Revenues**		62.2
20	**Income Tax**	9	27.3
21	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20)		1,668.3
22	**Amortization of Variance & Deferral Account Amounts**	10	(37.9)
23	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 21 + line 22)		1,630.4

Notes:

1 Per Ex. B1-1-1 Table 1.
2 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
3 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
4 Per Ex. F1-1-1, Table 1, line 6.
5 Per Ex. F1-1-1, Table 1, line 7.
6 Per Ex. F4-1-1, Table 1, line 10.
7 Per Ex. F4-2-1, Table 1, line 5.
8 Per Ex. G1-1-1, Table 1, line 7.
9 Per Ex. F4-2-1, Table 1, line 1.
10 Per Ex. H1-2-1 Table 1, col. (h), line 19.

Table 2
Summary of Revenue Requirement - OPG Nuclear Facilities ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	14,920.0	15,375.4	15,247.3	15,769.2	22,435.9
2	**Working Capital**	1	897.1	975.3	1,040.2	1,120.8	1,174.5
3	**Cash Working Capital**	1	(22.5)	(22.4)	(22.5)	(22.5)	(22.5)
4	**Total Rate Base**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Capitalization						
5	**Short-Term Debt**	2	261.9	259.9	248.9	246.6	274.6
6	**Long-Term Debt**	2	7,271.5	7,566.6	7,558.3	7,849.8	11,047.6
7	**Common Equity**	2	8,087.3	8,412.7	8,398.2	8,717.2	12,216.1
7a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	73.9	66.1	59.6	53.9	49.6
8	**Adjustment for Lesser of UNL or ARC**	2	100.1	23.0	0.0	0.0	0.0
9	**Total Capital**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Cost of Capital						
10	**Short-Term Debt**	3	13.3	12.2	12.0	11.4	13.2
11	**Long-Term Debt**	3	332.9	362.0	370.4	389.9	550.5
12	**Common Equity**	3	736.8	766.4	765.1	794.1	1,112.9
12a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	3.4	3.2	2.9	2.7	2.5
13	**Adjustment for Lesser of UNL or ARC**	3	4.7	1.1	0.0	0.0	0.0
14	**Total Cost of Capital**		1,091.0	1,144.9	1,150.5	1,198.1	1,679.0
	Expenses:						
15	**OM&A**	4	1,863.7	1,756.0	1,917.4	1,856.3	2,153.5
16	**Fuel**	5	150.9	221.7	223.6	261.2	306.1
17	**Depreciation & Amortization**	6	663.3	708.5	730.3	779.8	992.6
18	**Property Tax**	7	14.0	14.2	14.5	14.8	15.0
19	**Total Expenses**		2,691.9	2,700.5	2,885.7	2,912.1	3,467.2
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**	8	(5.2)	11.5	(18.1)	7.3	(17.1)
21	**Ancillary and Other Revenue**	9	6.3	32.7	13.8	13.5	23.6
22	**Total Other Revenues**		1.1	44.2	(4.3)	20.8	6.5
22a	**Concurrent Cost Recovery - Pickering Refurbishment Program**	14	297.6	479.9	667.7	832.0	646.2
23	**Income Tax**	10	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
24	**Revenue Requirement Before Stretch Factor** (line 14 + line 19 - line 22 + Line 22a + line 23)		4,062.8	4,264.4	4,691.6	4,904.8	5,769.3
25	**Cumulative Nuclear Stretch Dollars**	11	0.0	7.0	14.6	22.5	31.7
26	**Revenue Requirement Net of Stretch Factor** (line 24 - line 25)		4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
27	**Amortization of Variance & Deferral Account Amounts**	12	134.5	134.5	134.5	67.7	67.7
28	**Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts** (line 26 + line 27)		4,197.3	4,391.9	4,811.5	4,950.1	5,805.3

Notes:
1 Per Ex. B1-1-1 Table 2.
2 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
3 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
4 Per Ex. F2-1-1, Table 1a, line 16.
5 Per Ex. F2-1-1, Table 1a, line 17.
6 Per Ex. F4-1-1, Table 2, line 11.
7 Per Ex. F4-2-1, Table 2, line 4.
8 Per Ex. G2-2-1, Table 1, line 3.
9 Per Ex. G2-1-1, Table 1, line 7.
10 Per Ex. F4-2-1, Table 2, line 1.
11 Per Ex. I1-3-1, Table 2, line 23.
12 Per Ex. H1-2-1 Table 2, col. (h)-(l), line 32.
13 Per Ex. C1-1-1, Tables 1-5, line 5. Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB-approved settlement proposal in EB-2020-0290 (Settlement Proposal, p. 23).
14 Per Ex. I1-1-1, Table 7, line 7.

Table 2a
Summary of Revenue Requirement - DNNP Facilities ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	0.0	0.0	0.0	1,360.5	6,507.4
2	**Working Capital**	1	0.0	0.0	2.1	11.1	25.0
3	**Cash Working Capital**	1	0.0	0.0	0.0	(0.6)	(2.4)
4	**Total Rate Base**		0.0	0.0	2.1	1,371.1	6,530.0
	Capitalization						
5	**Short-term Debt**	2	0.0	0.0	0.0	0.0	0.0
6	**Long-Term Debt**	2	0.0	0.0	0.0	0.0	0.0
7	**Common Equity**	2	0.0	0.0	2.1	1,371.1	6,530.0
8	**Total Capital**		0.0	0.0	2.1	1,371.1	6,530.0
	Cost of Capital						
9	**Short-term Debt**	3	0.0	0.0	0.0	0.0	0.0
10	**Long-Term Debt**	3	0.0	0.0	0.0	0.0	0.0
11	**Common Equity**	3	0.0	0.0	0.2	124.9	594.9
12	**Total Cost of Capital**		0.0	0.0	0.2	124.9	594.9
	Expenses:						
13	**OM&A**	4	77.0	80.1	70.8	118.7	259.3
14	**Fuel**		9.1	13.8	12.7	18.1	49.8
15	**Depreciation & Amortization**	5	0.0	0.0	0.0	22.6	109.7
16	**Property Tax**	6	0.0	0.0	0.0	0.8	3.7
17	**Total Expenses**		86.1	93.9	83.5	160.2	422.5
	Less:						
	Other Revenues						
18	**Ancillary and Other Revenue**		0.0	0.0	0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0	0.0	0.0
20	**Concurrent Cost Recovery - DNNP**	7	214.9	284.8	321.2	274.2	24.6
21	**Income Tax**	8	0.0	0.0	0.0	0.0	0.0
22	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20 + line 21)		301.0	378.8	404.9	559.3	1,042.0
23	**Amortization of Variance & Deferral Account Amounts**		n/a	n/a	n/a	n/a	n/a
24	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 22)		301.0	378.8	404.9	559.3	1,042.0

Notes:
1 Per Ex. B1-1-1 Table 3.
2 Per Ex. C1-1-1 Tables 14 through 18 (col. (a)).
3 Per Ex. C1-1-1 Tables 14 through 18 (col. (d)).
4 Per Ex. F2-1-1, Table 1b, line 9.
5 Per Ex. F4-1-1, Table 2, line 12.
6 Per Ex. F4-2-1, Table 2a, line 2.
7 Per Ex. I1-1-1, Table 6, line 7.
8 Per Ex. F4-2-1, Table 2a, line 1.

Table 3a
Summary of Revenue Deficiency - Regulated Hydroelectric
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027
			(a)
1	**Forecast Production (TWh)**	1	32.5
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	43.88
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,424.4
4	**Revenue Requirement ($M)**	3	**1,668.3**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**243.9**

Notes:
1 Ex. E1-1-1, Table 1, line 4.
2 EB-2020-0290 Payment Amounts Order, p. 4.
3 Ex. I1-1-1, Table 1, line 21.

Numbers may not add due to rounding.

Table 3b
Summary of Revenue Deficiency - OPG Nuclear Facilities
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	18.7	26.7	25.1	26.8	28.9
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	111.33	111.33	111.33	111.33	111.33
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		2,081.0	2,971.6	2,790.6	2,986.3	3,222.2
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	**4,062.8**	**4,257.4**	**4,677.0**	**4,882.4**	**5,737.6**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**1,981.8**	**1,285.8**	**1,886.3**	**1,896.1**	**2,515.3**

Notes:
1 Ex. E2-1-1, Table 1, line 3.
2 EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 3, col. (e).
3 Ex. I1-1-1, Table 2, line 26.

Numbers may not add due to rounding.

Table 4
Determination of 2025 Forecast Return on Equity ($M)

Line No.	Description	Note	2025 Forecast Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	33.0	36.9	69.9
2	**Payment Amount ($/MWh)**	2	47.18	111.61	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,556.2	4,119.0	5,675.2
	Expenses:				
4	**OM&A**	3	427.9	2,044.5	2,472.4
5	**Fuel and GRC**	4	357.2	255.1	612.3
6	**Depreciation**	5	190.8	540.3	731.0
7	**Property Taxes**	6	1.1	12.2	13.3
8	**Total Expenses**		977.0	2,852.1	3,829.0
9	**Ancillary and Other Revenue**	7	70.9	46.6	117.5
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	4.7	7.3	12.0
11	**Long-Term Debt**	9	180.6	279.0	459.6
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	15.5	15.5
13	**Cost of Capital Excluding Return on Equity**		185.3	301.8	487.1
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components**	12	46.6	261.3	307.9
16	**Total Deferral and Variance Account Adjustments**		(52.9)	47.2	(5.7)
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components** (line 8 - line 9 + line 13 - line 16)		1,144.3	3,060.1	4,204.3
18	**2025 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		411.9	1,059.0	1,470.9
19	**Income Tax**	13	68.1	171.4	239.5
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	14.3	37.8	52.1
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(6.0)	(6.0)
22	**Total Income Tax** (line 19 + line 20 + line 21)		82.4	203.2	285.6
23	**2025 Forecast Return on Equity** (line 18 - line 22)		329.5	855.8	1,185.2
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 7, col. (a), line 5)**				12.46%

Notes:
Refer to Table 4a

Table 4a

Notes to Ex. I1-1-1 Table 4

Notes:

1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (j). Col. (b) from Ex. E2-1-1, Table 1, line 3, col. (f).

2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (k), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (h), line 21.
Col. (b) is the sum of the nuclear payment amount of $102.85/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $5.34/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (k), line 32 and nuclear payment rider of $3.42/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (h), line 31.

3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (f).

4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (f).

5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (f).

6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (f).

7 Col. (a) from Ex. G1-1-1, Table 1, col. (j), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (f), line 7.

8 Col. (c) from Ex. C1-1-1, Table 7, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

9 Col. (c) from Ex. C1-1-1, Table 7, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

10 From Ex. C1-1-1, Table 7, col. (d), line 7.

11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (k) and EB-2023-0336 PAO, App. A, Table 1, col. (h), line 16.

12 Forecast 2025 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	45.4
12b	Less: Tax Gross-up Components of Transactions in:	13.1
12c	Less: Tax Variance Components of Transactions in:	(14.3)
12d	Transactions Excluding Income Tax Components	46.6
	Nuclear :	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	217.7
12f	Less: Tax Gross-up Components of Transactions in:	(5.8)
12g	Less: Tax Variance Components of Transactions in:	(37.8)
12h	Transactions Excluding Income Tax Components	261.3

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (j). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (f).

14 Regulated Hydroelectric: line 12c. Nuclear: line 12g.

15 EB-2020-0290 PAO, Table 22, col. (d) (line 2 + line 3) x 25%

Numbers may not add due to rounding.

Table 5
Determination of 2026 Forecast Return on Equity ($M)

Line No.	Description	Note	2026 Forecast Regulated Hydroelectric	2026 Forecast Nuclear	2026 Forecast Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	32.8	32.5	65.2
2	**Payment Amount ($/MWh)**	2	47.18	123.76	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,545.8	4,016.8	5,562.6
	Expenses:				
4	**OM&A**	3	439.4	2,118.2	2,557.6
5	**Fuel and GRC**	4	354.3	239.2	593.5
6	**Depreciation**	5	194.8	617.7	812.4
7	**Property Taxes**	6	1.0	13.5	14.5
8	**Total Expenses**		989.5	2,988.6	3,978.0
9	**Ancillary and Other Revenue**	7	76.0	39.4	115.4
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	6.0	10.2	16.1
11	**Long-Term Debt**	9	202.5	344.6	547.1
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	9.6	9.6
13	**Cost of Capital Excluding Return on Equity**		208.4	364.3	572.7
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components and Concurrent Cost Recovery**	12	84.8	(309.4)	(224.6)
16	**Total Deferral and Variance Account Adjustments**		(14.7)	(523.5)	(538.2)
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components and Concurrent Cost Recovery** (line 8 - line 9 + line 13 - line 16)		1,136.6	3,836.9	4,973.6
18	**2026 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		409.2	179.8	589.0
19	**Income Tax**	13	(3.3)	(37.1)	(40.4)
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	37.1	27.2	64.3
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(24.7)	(24.7)
22	**Total Income Tax** (line 19 + line 20 + line 21)		33.8	(34.6)	(0.8)
23	**2026 Forecast Return on Equity** (line 18 - line 22)		375.3	214.5	589.8
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 6, col. (a), line 5)**				5.59%

Notes:
Refer to Table 5a

Table 5a
Notes to Ex. I1-1-1 Table 5

Notes:
1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (k). Col. (b) from Ex. E2-1-1, Table 1, line 5, col. (g).
2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (l), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (i), line 21.
Col. (b) is the sum of the nuclear payment amount of $111.33/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $7.58/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (l), line 32 and nuclear payment rider of $4.85/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (i), line 31.
3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (g).
4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (g).
5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (g).
6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (g).
7 Col. (a) from Ex. G1-1-1, Table 1, col. (k), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (g), line 7.
8 Col. (c) from Ex. C1-1-1, Table 6, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).
9 Col. (c) from Ex. C1-1-1, Table 6, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).
10 From Ex. C1-1-1, Table 6, col. (d), line 7.
11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (l) and EB-2023-0336 PAO, App. A, Table 1, col. (i), line 16.
12 Forecast 2026 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	57.8
12b	Less: Tax Gross-up Components of Transactions:	10.2
12c	Less: Tax Variance Components of Transactions:	(37.1)
12d	Transactions Excluding Income Tax Components	84.8
	Nuclear:	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	(290.3)
12f	Less: Tax Gross-up Components of Transactions:	46.2
12g	Less: Tax Variance Components of Transactions:	(27.2)
12h	Transactions Excluding Income Tax Components	(309.4)

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (k). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (g).
14 Regulated Hydroelectric: line 12c. Nuclear: line 12g.
15 EB-2020-0290 PAO, Table 22, col. (e) (line 2 + line 3) x 25%

Table 6
Calculation of Forecast Concurrent Cost Recovery - Darlington New Nuclear Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	2,250.5	3,884.0	5,504.7	6,401.4	6,706.1	494.3
2	**Capital Expenditures**	1	1,633.5	1,620.7	896.7	304.7	373.2	0.0
3	**In-Service**	2	0.0	0.0	0.0	0.0	6,584.9	0.0
4	**Closing Balance** (line 1 + line 2 - line 3)		3,884.0	5,504.7	6,401.4	6,706.1	494.3	494.3
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,067.2	4,694.3	5,953.0	6,553.7	5,520.8	494.3
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery** (line 5 x line 6)	4	112.0	214.9	284.8	321.2	274.2	24.6

Notes

1 Per Ex. D2-4-8, Table 1, line 3. Opening balance in col. (a) per Ex. D2-4-8, Table 1, sum of line 3, col. (a) through col. (f).

2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). 2030 in-service is weighted 2.5/12 months based on in-service date of October 17, 2030. Per Ex. B3-3-1, Table 2a, Note 1.

3 Per Ex. C1-1-1, Tables 1-5: line 2, col. (c).

4 Over the 2027-2031 period, concurrent cost recovery amounts of $1,004.9M relate to Unit 1 and $114.9M relate to Units 2 through 4.

Table 7
Calculation of Forecast Concurrent Cost Recovery - Pickering Refurbishment Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	1,887.0	4,773.3	8,225.9	11,833.5	15,411.7	18,093.2
2	**Capital Expenditures**	1	3,045.6	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5
3	**In-Service**	2	159.3	20.6	0.0	0.0	0.0	9,688.0
4	**Closing Balance** (line 1 + line 2 - line 3)		4,773.3	8,225.9	11,833.5	15,411.7	18,093.2	10,265.7
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,303.6	6,499.6	10,029.7	13,622.6	16,752.5	12,968.4
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery**		120.6	297.6	479.9	667.7	832.0	646.2

Notes
1 Per Ex. D2-3-8, Table 1, line 4. Opening balance in col. (a) per Ex. D2-3-10, Table 1, sum of line 4: col. (a) through col. (f).
2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). The 2031 in-service is weighted 7.5/12 based on in-service date of May 15, 2031. See Ex. B3-3-1 Table 2a, Note 1 for further details.
3 Per EB-2020-0290, PAO, Appendix A, Table 15, line 2, col. (c) for 2026 and Ex. C1-1-1, Tables 1-5: line 2, col. (c) for 2027-2031.

CONSUMER IMPACT

1.0 PURPOSE

This evidence describes the estimated impact of the proposed payment amounts and payment rider changes on a residential electricity consumer consuming at the 750 kWh per month level (the "typical consumer").

2.0 CONSUMER IMPACT

The Application has calculated the weighted average of regulated hydroelectric and shaped nuclear payment amounts and payment amount riders, weighted by forecast production to be \$110.03/MWh for 2027, \$118.62/MWh for 2028, \$123.42/MWh for 2029, \$125.83/MWh for 2030, and \$141.02/MWh for 2031.[1,2]

The annual change in weighted average payment amounts and riders is applied to the typical consumer's usage of OPG's regulated hydroelectric and regulated nuclear facilities and the DNNP facilities, after adjusting for line losses and accounting for these facilities' share of the province's generation. Typical consumer data is based on the average electricity distributor bill information provided on the OEB's website at:
https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator

The estimated monthly consumer bill impacts associated with the revenue requirements and clearance of deferral and variance accounts are reflected in Chart 1, as calculated in Ex. I1-1-2, Table 1.

Chart 1 - Annualized Residential Consumer Impact

	2027	2028	2029	2030	2031
Typical Bill (\$/Month)	\$142.10	\$142.10	\$142.10	\$142.10	\$142.10
Typical Bill Impact (\$/Month)	\$7.93	\$2.44	\$1.33	\$0.69	\$4.62
Typical Bill Impact (%)	5.6%	1.7%	0.9%	0.5%	3.3%

[1] Includes shaped 2027-2031 nuclear payment amounts applicable to OPG's nuclear facilities and the DNNP facilities, as illustrated in Ex. I1-3-1, Table 1. An illustrative regulated hydroelectric payment amount is used for the 2028-2031 period, using the proposed ratemaking methodology, as per Ex. I1-2-1.
[2] Determination of weighted average payment amounts per Ex. I-1-2, Table 2.

Table 1
Annualized Residential Consumer Impact
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	2027 Amount	2028 Amount	2029 Amount	2030 Amount	2031 Amount	2027-2031 Average
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)	246	284	276	287	304	280
3	**Typical Bill[1] ($/Month)**	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	7.93	2.44	1.33	0.69	4.62	3.40
5	**Typical Bill Impact (%)** (line 4 / line 3)	5.6%	1.7%	0.9%	0.5%	3.3%	2.4%
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	77.75	110.03	118.62	123.42	125.83	
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	110.03	118.62	123.42	125.83	141.02	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	32.28	8.59	4.80	2.41	15.19	
9	Total Regulated Production[4] (TWh)	51.2	59.2	57.5	59.8	63.3	
10	Forecast of 2027 Provincial Demand[5] (TWh)	163.9	163.9	163.9	163.9	163.9	
11	OPG and DNNP LP Proportion of Consumer Usage (line 9 / line 10)	31.2%	36.1%	35.1%	36.5%	38.6%	

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: https://www.oeb.ca/consumer-information-and-protection/bill-calculator, accessed November 20, 2025. Typical Consumption includes line losses (Average loss factor of utility rate zones = 1.04996)

2 From Ex. I1-1-2 Table 2, line 9.

3 Per Ex. I1-3-1 Table 1.

4 From Ex. I1-1-2 Table 2, line 3 + line 6.

5 Based on forecast demand for 2027 (163.9 TWh) from Figure 2 of IESO Annual Planning Outlook, released April 2025.

Numbers may not add due to rounding.

Table 2
Computation of Percent Change in Payment Amounts
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 2	Note 2	Note 2	Note 2	Note 2
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	3	43.88	51.39	54.97	59.20	62.02	64.21
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	4	3.30	(1.17)	(1.17)	(1.17)	0.00	0.00
3	**Hydroelectric Production Forecast (HPF) TWh**	5	33.0	32.5	32.5	32.5	32.5	32.5
4	**Nuclear Payment Amount (NPA) ($/MWh)**	6	111.33	206.70	192.42	202.74	199.16	219.60
5	**Nuclear Payment Rider (NPR) ($/MWh)**	7	12.43	7.19	5.04	5.36	2.48	2.19
6	**Nuclear Production Forecast (NPF) TWh**	8	21.9	18.7	26.7	25.1	27.3	30.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.87	29.52	32.75	33.68	32.91
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	78.16	89.10	90.67	92.15	108.11
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	110.03	118.62	123.42	125.83	141.02
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			41.5%	7.8%	4.0%	2.0%	12.1%

Notes:
1 Payment amounts, riders and production forecasts approved in EB-2020-0290 Payment Amounts Order plus payment riders approved in EB-2023-0336.
2 Payment amounts and payment riders proposed in this application.
3 Per Ex. I1-2-1, Table 1. Cols. (c) to (f) are illustrative only.
4 Per Ex. H1-2-1, Table 1, line 21.
5 For 2027: Per Ex. E1-1-1, Table 1, col. (l), line 4.
6 Per Ex. I1-3-1, Table 1, line 9. Shaped payment amounts are based on the combined revenue requirements of the OPG nuclear facilities and the DNNP facilities.
7 Per Ex. H1-2-1, Table 2, line 34.
8 For 2027-2031: Per Ex. E2-1-1, Table 1, line 5. Includes production forecasts of the OPG nuclear facilities and DNNP facilities.

Table 1
Annualized Residential Consumer Impact
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	2027 Amount	2028 Amount	2029 Amount	2030 Amount	2031 Amount	2027-2031 Average
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)	246	284	276	287	304	280
3	**Typical Bill[1] ($/Month)**	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	7.93	2.44	1.33	0.69	4.62	3.40
5	**Typical Bill Impact (%)** (line 4 / line 3)	5.6%	1.7%	0.9%	0.5%	3.3%	2.4%
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	77.75	110.03	118.62	123.42	125.83	
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	110.03	118.62	123.42	125.83	141.02	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	32.28	8.59	4.80	2.41	15.19	
9	Total Regulated Production[4] (TWh)	51.2	59.2	57.5	59.8	63.3	
10	Forecast of 2027 Provincial Demand[5] (TWh)	163.9	163.9	163.9	163.9	163.9	
11	OPG and DNNP LP Proportion of Consumer Usage (line 9 / line 10)	31.2%	36.1%	35.1%	36.5%	38.6%	

Notes:
1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: https://www.oeb.ca/consumer-information-and-protection/bill-calculator, accessed November 20, 2025. Typical Consumption includes line losses (Average loss factor of utility rate zones = 1.04996)
2 From Ex. I1-1-2 Table 2, line 9.
3 Per Ex. I1-3-1 Table 1.
4 From Ex. I1-1-2 Table 2, line 3 + line 6.
5 Based on forecast demand for 2027 (163.9 TWh) from Figure 2 of IESO Annual Planning Outlook, released April 2025.

Numbers may not add due to rounding.

Table 2
Computation of Percent Change in Payment Amounts
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 2	Note 2	Note 2	Note 2	Note 2
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	3	43.88	51.39	54.97	59.20	62.02	64.21
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	4	3.30	(1.17)	(1.17)	(1.17)	0.00	0.00
3	**Hydroelectric Production Forecast (HPF) TWh**	5	33.0	32.5	32.5	32.5	32.5	32.5
4	**Nuclear Payment Amount (NPA) ($/MWh)**	6	111.33	206.70	192.42	202.74	199.16	219.60
5	**Nuclear Payment Rider (NPR) ($/MWh)**	7	12.43	7.19	5.04	5.36	2.48	2.19
6	**Nuclear Production Forecast (NPF) TWh**	8	21.9	18.7	26.7	25.1	27.3	30.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.87	29.52	32.75	33.68	32.91
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	78.16	89.10	90.67	92.15	108.11
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	110.03	118.62	123.42	125.83	141.02
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			41.5%	7.8%	4.0%	2.0%	12.1%

Notes:
1 Payment amounts, riders and production forecasts approved in EB-2020-0290 Payment Amounts Order plus payment riders approved in EB-2023-0336.
2 Payment amounts and payment riders proposed in this application.
3 Per Ex. I1-2-1, Table 1. Cols. (c) to (f) are illustrative only.
4 Per Ex. H1-2-1, Table 1, line 21.
5 For 2027: Per Ex. E1-1-1, Table 1, col. (l), line 4.
6 Per Ex. I1-3-1, Table 1, line 9. Shaped payment amounts are based on the combined revenue requirements of the OPG nuclear facilities and the DNNP facilities.
7 Per Ex. H1-2-1, Table 2, line 34.
8 For 2027-2031: Per Ex. E2-1-1, Table 1, line 5. Includes production forecasts of the OPG nuclear facilities and DNNP facilities.

CONCURRENT COST RECOVERY

1.0 PURPOSE

This evidence provides a description of the framework for recovery of interest amounts associated with the Pickering Refurbishment Program ("PRP") and the Darlington New Nuclear Program ("DNNP") prior to such assets being placed in service as prescribed by Ontario Regulation 53/05 ("O. Reg. 53/05") ("concurrent cost recovery" or "CCR") and presents such forecast interest amounts sought for recovery in this Application.

2.0 OVERVIEW

Pursuant to the requirements of O. Reg. 53/05, the Application seeks approval to include:

- In DNNP LP's revenue requirements, an amount calculated by multiplying the forecast cumulative capital costs incurred in respect of the DNNP by OPG's long-term cost of debt rate;[1] and
- In OPG's revenue requirements, an amount calculated by multiplying the forecast cumulative capital costs incurred in respect of the PRP by OPG's long-term cost of debt rate.

Additionally, O. Reg. 53/05 establishes variance accounts related to CCR interest amounts:

- For DNNP LP, an account that records the difference between the forecast DNNP CCR amount included in DNNP LP's revenue requirement (as determined above) and an amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term cost of debt rate;[2] and
- For OPG, an account that records the difference between the forecast PRP CCR amount included in OPG's revenue requirement (as determined above) and an amount calculated

[1] O. Reg. 53/05 also requires DNNP CCR amounts in OPG's revenue requirement prior to certain conditions being met in establishing DNNP LP as a prescribed generator. Since the Application assumes that DNNP LP will meet these requirements before January 1, 2026, this evidence focuses on the DNNP LP provisions.

[2] O. Reg. 53/05 also establishes a CCR-related variance account for OPG, to be effective up until certain conditions are met in establishing DNNP LP as a prescribed generator. Since the Application assumes that DNNP LP will meet these requirements before January 1, 2026, this evidence focuses on the DNNP LP provisions.

by multiplying the actual cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term cost of debt rate.

Additional information on the PRP is provided in Ex. D2-3-1 through Ex. D2-3-11. Additional information on the DNNP is provided in Ex. D2-4-1 through Ex. D2-4-10. The two variance accounts are identified in Ex. H1-1-1.

Section 3.0 summarizes the CCR requirements set out in O. Reg. 53/05. Section 4.0 presents the calculation of the CCR interest amounts, in respect of the DNNP, for inclusion in DNNP LP's revenue requirements. Section 5.0 presents the calculation of the CCR interest amounts, in respect of the PRP, for inclusion in OPG's nuclear revenue requirements. Section 6.0 presents the Application's implementation proposal for the requirement to disposition annually the balances in the CCR variance accounts pursuant to O. Reg. 53/05, including amounts that will be recorded in 2026 and must be recovered during 2027.

3.0 REQUIREMENTS OF O. REG. 53/05

O. Reg. 53/05, as amended in December 2025, requires the OEB to provide for the recovery of CCR interest amounts in respect of the DNNP and the PRP prior to the underlying assets being placed in service.

Darlington New Nuclear Program

The applicable amendments to O. Reg. 53/05 appear in Part II and Part III of the regulation, with Part III only applying after DNNP LP is recognized as a prescribed generator for purposes of section 78.1 of the *Ontario Energy Board Act, 1998*.[3] Prior to Part III of the regulation taking effect, the rules governing the determination of payment amounts under section 6(2)11.1 and the variance account established under section 5.4.1 apply to OPG as the prescribed generator. Following Part III of the regulation taking effect, the rules governing the

[3] Section 8 of O. Reg. 53/05 requires the OEB to issue an order specifying satisfaction with certain conditions relating to DNNP LP before Part III takes effect. The Application expects that these requirements will be met by the end of 2025.

determination of payment amounts under section 14(2)5 and the variance account established under section 12 apply to DNNP LP as the prescribed generator.

As set out below, the sections outlining rules governing the determination of payment amounts are the same under Part II and Part III, with the only exception being the prescribed generator to which the rules apply. Similarly, the variance accounts established under Part II and Part III are the same, with the only exception being the prescribed generator to which the accounts apply.

For the DNNP facilities, Section 14(2)5 requires CCR interest amounts to be included in the DNNP LP revenue requirement as follows:

> In setting payment amounts for the DNNP Nuclear Generating Station, the Board shall,
>
> i. include in the Board-approved revenue requirement of the DNNP generator for each year the amount calculated by multiplying the forecast cumulative capital costs incurred by the DNNP generator in respect of the Darlington New Nuclear Project, other than capital costs incurred in respect of any small modular reactor that has come into service or been abandoned, by Ontario Power Generation Inc.'s long-term debt rate,
>
> ii. ensure that the balance recorded in the variance account established under subsection 12 (1) is recovered on an annual basis in the year following the year in which the balance was recorded, to the extent that the Board is satisfied that the amounts are accurately recorded in the account, and

Under Section 12, a Darlington New Nuclear Project Variance Account re Capital Cost Amounts (herein referred to as "DNNP CCR variance account") is established as follows:[4]

[4] Section 8 of O. Reg. 53/05 requires the OEB issue an order specifying satisfaction with certain conditions relating to DNNP LP before section 12 takes effect. Section 12(3) and 14(2)1 add that the account shall include amounts after the effective date of the lease between OPG and DNNP LP. The Application expects that these requirements, including the lease between OPG and DNNP LP, will be met by the end of 2025.

Darlington New Nuclear Project variance account re capital cost amounts

12. (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that records differences between,

(a) the amount calculated by multiplying the actual cumulative capital costs incurred by the DNNP generator in respect of the Darlington New Nuclear Project by Ontario Power Generation Inc.'s long-term debt rate; and

(b) the amount included in payments made under section 78.1 of the Act in accordance with subparagraph 5 i of subsection 14(2).

(2) The account shall not include,

(a) amounts respecting capital costs in respect of any small modular reactor that has come into service or been abandoned; or

(b) amounts already included in a variance account established under subsection 5.4.1 (1) or 11 (1).

(3) The account shall include any amounts referred to in clause (1) (a) that arose on or after the effective date of the lease referred to in paragraph 2 of section 8 and before the DNNP transition date.

(4) The DNNP generator shall record interest on the balance of the account at Ontario Power Generation Inc.'s long-term debt rate, compounded annually.

Pickering Refurbishment Program

The requirements of Section 6(2)12.1 of O. Reg. 53/05 are as follows:

12.1 In setting payment amounts for the nuclear facilities, the Board shall,

i. include in the Board-approved revenue requirement for the nuclear facilities for each year the amount calculated by multiplying the forecast cumulative capital costs incurred by Ontario Power Generation Inc. in respect of the Pickering B

Refurbishment Project, other than the capital costs referred to in clauses 5.8 (2) (a) and (b), by Ontario Power Generation Inc.'s long-term debt rate,

ii. ensure that the balance recorded in the variance account established under subsection 5.8 (1) is recovered on an annual basis in the year following the year in which any amount was recorded, to the extent that the Board is satisfied that the amounts are accurately recorded in the account, and

iii. ensure that any duplication of amounts accepted by the Board as capital costs under subparagraph 2 i of subsection 14 (2) is avoided.

Under Section 5.8 of O. Reg. 53/05, a PRP CCR variance account is established as follows:

Pickering B Refurbishment Project variance account

5.8 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records the difference between,

(a) the amount calculated by multiplying the actual cumulative capital costs incurred by Ontario Power Generation Inc. in respect of the Pickering B Refurbishment Project by Ontario Power Generation Inc.'s long-term debt rate; and

(b) the amount included in payments made under section 78.1 of the Act in accordance with subparagraph 12.1 i of subsection 6 (2).

(2) The account shall not include,

(a) amounts respecting capital costs related to a generating unit that has been refurbished and returned to service as part of the Pickering B Refurbishment Project;

(b) amounts respecting capital costs related to the refurbishment, construction or acquisition of a structure, equipment or other thing that is part of the Pickering B Refurbishment Project and that has been returned to or come into service; or

(c) amounts included in the variance account established under section 5.7.

(3) Ontario Power Generation Inc. shall record interest on the balance of the account at its long-term debt rate, compounded annually.

4.0 CONCURRENT COST RECOVERY INTEREST AMOUNTS – DNNP

Pursuant to the requirements identified in Section 3.0 above, the Application seeks to include CCR interest amounts of $214.9M in 2027, $284.8M in 2028, $321.2M in 2029, $274.2M in 2030, and $24.6M in 2031 in respect of the DNNP in the DNNP LP's revenue requirements. The calculations supporting these forecast amounts can be found at Ex. I1-1-1, Table 6. In accordance with Section 14(2)5 of O. Reg. 53/05, there are three inputs into the calculation of these interest amounts:

1) **Forecast of DNNP cumulative capital costs**. Interest is calculated on the forecast of cumulative capital costs to be expended. DNNP capital expenditures are discussed in Ex. D2-4-8, and the amounts used in the CCR calculation can be found in Ex. D2-4-8, Table 1. As discussed in Ex. D2-4-8, these amounts do not include capitalization of interest effective January 1, 2026.
2) **In-service amounts**. Per section 14(2)5 of O. Reg. 53/05, interest is not calculated on capital costs in respect of facilities that have come into service or been abandoned. In-service amounts therefore reduce the cumulative capital costs on which interest is applied. The DNNP in-service amount in 2030 is discussed in Ex. D2-4-8, and the amount used in the calculation can be found in Ex. D2-4-8, Table 3.
3) **OPG cost of long-term borrowing**. Per section 14(2)5 of O. Reg. 53/05, in conjunction with the definition of "long-term debt" in subsection 0.1(1), interest is to be calculated using OPG's long-term debt rate as approved by the OEB. The long-term debt rates proposed for the IR term can be found in Ex. C1-1-1, Tables 1-6 and are discussed in Ex. C1-1-2.

As further discussed in Ex. H1-1-1, Section 6.3, O. Reg. 53/05 Section 12 establishes a DNNP CCR variance account to record the difference between: (i) the amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's OEB-approved long-term debt rate; and (ii) the CCR interest amount included in DNNP LP revenue requirement as determined above. O. Reg. 53/05 Section 14(2)5(ii) requires the balance of this account to be recovered on an annual basis in the year following the year in which any amount was recorded. This includes amounts to be recorded in the account for 2026, which must be recovered during 2027. Exhibit I1-1-1, Table 6 presents the forecast 2026 CCR interest amount of $112.0M in respect of the DNNP.

As shown in Ex. I1-1-1, Table 6, the forecast CCR interest amounts sought in the Application are calculated on an annual basis using a mid-year average methodology, with in-service additions over $50M weighted using the month in which they are reflected to improve accuracy. The actual CCR interest amounts will be derived in the same manner as the forecast amounts, but will be based on the actual capital expenditures and in-service amounts and will be calculated on a monthly basis to provide greater precision and facilitate monthly entry-making into the DNNP CCR Variance Account.

5.0 CONCURRENT COST RECOVERY INTEREST AMOUNTS – PRP

Pursuant to the requirements identified in Section 3.0 above, the Application seeks to include CCR interest amounts of $297.6M in 2027, $479.9M in 2028, $667.7M in 2029, $832.0M in 2030, and $646.2M in 2031 in respect of the PRP in OPG's revenue requirements. The calculations supporting these forecast amounts can be found at Ex. I1-1-1, Table 7. In accordance with Section 6(2)12.1 of O. Reg. 53/05, there are three inputs into the calculation of these interest amounts:

1) **Forecast of PRP cumulative capital costs**. Interest is calculated on the forecast of cumulative capital costs to be expended. PRP capital expenditures are discussed in Ex. D2-3-8, and the amounts used in the CCR calculation can be found in Ex. D2-3-8, Table 1. As discussed in Ex. D2-3-8, these amounts do not include capitalization of interest effective January 1, 2026.
2) **In-service amounts.** Per section 6(2)12.1 and section 5.8(2) of O. Reg. 53/05, interest is not calculated on capital costs related to facilities once that facility has been returned to or come into service. In-service amounts therefore reduce the cumulative capital costs on

which interest is applied. PRP in-service amounts are discussed in Ex. D2-3-8, and the amounts used in the calculation can be found in Ex. D2-3-8, Table 2.

3) **OPG cost of long-term borrowing.** Per Section 6(2)12.1 of O. Reg. 53/05, in conjunction with the definition of "long-term debt" in subsection 0.1(1), interest is to be calculated using OPG's long-term debt rate as approved by the OEB. These long-term debt rates proposed for the IR term can be found in Ex. C1-1-1, Tables 1-6, and are discussed in Ex. C1-1-2.

As discussed in Ex. H1-1-1, Section 5.30, O. Reg. 53/05 Section 5.8 establishes a PRP CCR variance account to record the difference between: (i) the amount calculated by multiplying the actual cumulative capital costs incurred by OPG in respect of the PRP by OPG's OEB-approved long-term debt rate; and (ii) the CCR interest amount included in OPG's revenue requirement as determined above. O. Reg. 53/05 section 6(2)12.1 requires the balance of this account to be recovered on an annual basis in the year following the year in which any amount was recorded. This includes amounts to be recorded in the account for 2026, which must be recovered during 2027. Exhibit I1-1-1, Table 7 presents the forecast 2026 CCR interest amount of $120.6M in respect of the PRP.

As shown in Ex. I1-1-1, Table 7, the forecast CCR interest amounts sought in the Application are calculated on an annual basis using a mid-year average methodology, with in-service additions over $50M weighted using the month in which they are reflected to improve accuracy. The actual CCR interest amounts will be derived in the same manner as the forecast amounts, but will be based on the actual capital expenditures and in-service amounts and will be calculated on a monthly basis to provide greater precision and facilitate monthly entry-making into the PRP CCR variance account.

6.0 PROPOSED PROCESS FOR CCR VARIANCE ACCOUNT ANNUAL CLEARANCE

As noted above, O. Reg. 53/05 requires the balances of the DNNP CCR variance account and the PRP CCR variance account to be recovered in the year following which they are recorded. The Application expects this to begin with recovering the 2026 balances during 2027.

The Application proposes to file a CCR annual clearance application in the first quarter of each year of the IR term, starting with Q1 2027. In each annual CCR clearance application, the balances of the DNNP CCR variance account and the PRP CCR variance account will be provided with supporting calculations comparing the CCR interest on actual capital expenditures (taking into account actual in-service amounts), to the CCR interest on the forecast capital expenditures underpinning CCR interest amounts included in OEB-approved payment amounts.

It is expected that the annual CCR clearance application will propose to recover the sum of the balances in the two accounts through a rate rider, over a forecast combined nuclear production (i.e., OPG nuclear facilities and the DNNP facilities)[5], over the remaining months of the year. For example, if the annual CCR clearance application is filed and adjudicated before the end of February, the application could propose recovering the balance over the period from March 1-December 31. If more time is required and a decision is issued in April, for example, the balance could be recovered over the period from May 1-December 31.

[5] Recovering the sum of the DNNP CCR variance account and PRP CCR variance account balances over the sum of production from the DNNP facilities and OPG nuclear facilities is consistent with O. Reg. 53/05, Section 14(2)8, which requires the OEB to determine a blended payment amount rider for OPG and the DNNP LP.

REGULATED HYDROELECTRIC PAYMENT AMOUNT

1.0 PURPOSE

This evidence presents OPG's requested 2027 payment amount for its regulated hydroelectric facilities.

2.0 REGULATED HYDROELECTRIC PAYMENT AMOUNT

OPG is seeking approval of a payment amount for its regulated hydroelectric facilities of $51.39/MWh, effective January 1, 2027, for the average hourly net energy production ("MWh") from the regulated hydroelectric facilities in any given month for each hour of that month.

OPG's revenues from the hydroelectric payment amount shall be adjusted by the following hydroelectric incentive mechanism, in any given month for each hour of that month:

- For the resource(s) at regulated hydroelectric facilities, for each hour where the IESO day-ahead market energy schedule (the "Day-Ahead Energy Schedule") differs from the average hourly energy schedule from the IESO's day-ahead market for that day (the "Average Day-Ahead Energy Schedule"), OPG's revenues will be adjusted by the difference between the Day-Ahead Energy Schedule and the Average Day-Ahead Energy Schedule, multiplied by the day-ahead locational marginal price for the resource for that hour. For the resource(s) at regulated hydroelectric facilities, for each hour where (1) the difference between the net energy production supplied to the IESO's real-time market and the Day-Ahead Energy Schedule ("Real-Time Energy Difference") differs from (2) the difference between the average hourly net energy production over that day and the Average Day-Ahead Energy Schedule for that day ("Average Real-Time Energy Difference"), OPG's revenues will be adjusted by the difference between the Real-Time Energy Difference and the Average Real-Time Energy Difference, multiplied by the real-time locational marginal price for the resource for that hour, calculated on a five-minute basis.

The requested payment amount is calculated in Ex. I1-2-1, Table 1. This table also presents the proposed regulated hydroelectric payment rider of $(1.17)/MWh effective January 1, 2027-December 31, 2029, as calculated in Ex. H1-2-1, Table 1.

Payment amounts for 2028-2031, determined using the ratemaking methodology proposed in Ex. A1-3-2, are included in the table for illustrative purposes.

Numbers may not add due to rounding.

Table 1
Payment Amounts and Riders – Regulated Hydroelectric Facilities
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027	Illustrative Payment Amounts[1] 2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Price Escalator (I-Factor)**	2	**3.49%**	**3.49%**	**3.49%**	**3.49%**	**3.49%**
2	Labour: Average Weekly Earnings - Ontario	2	4.85%	4.85%	4.85%	4.85%	4.85%
3	Non-Labour: Canadian Gross Domestic Product Implicit Price Index - Final Domestic Demand	2	3.24%	3.24%	3.24%	3.24%	3.24%
4	**Productivity Factor**	3	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
5	**Stretch Factor**	4	**0.15%**	**0.15%**	**0.15%**	**0.15%**	**0.15%**
6	**"I-X"** (line 1 - line 4 - line 5)		**3.34%**	**3.34%**	**3.34%**	**3.34%**	**3.34%**
7	**Custom Capital Factor** (Ex. I1-2-1 Table 2, line 10)	5		**4.33%**	**5.02%**	**2.04%**	**0.77%**
8	**GRC Adjustment** (Ex. I1-2-1 Table 2, Note 3, line 3c)	6		**-0.70%**	**-0.66%**	**-0.61%**	**-0.58%**
9	**Price Cap Index**			**6.96%**	**7.70%**	**4.76%**	**3.53%**
10	**Prior Year Hydroelectric Payment Amount ($/MWh)**			51.39	54.97	59.20	62.02
11	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	7	51.39	54.97	59.20	62.02	64.21
12	**Hydroelectric Payment Rider ($/MWh)**	8	(1.17)	(1.17)	(1.17)	0.00	0.00
14	**Total of Hydroelectric Payment Amounts Plus Riders** (line 11 + line 12 + line 13)		50.22	53.80	58.03	62.02	64.21

Notes:

1 Payment amounts for 2028-2031 are illustrative only - final payment amounts to be determined annually using I-factor values.
2 2027 inflation factor per 2026 inflation parameters published by the OEB in June 2025, and weightings per Ex. A1-3-2 Chart 2: 15.3% labour cost (line 2), 9.3% non-labour cost (line 3) and 75.4% capital cost (line 3).
3 Per Ex. A1-3-2, Section 2.3.2.1.
4 Per Ex. A1-3-2, Section 2.3.2.2.
5 Per Ex. A1-3-2, Section 2.3.3.
6 Per Ex. A1-3-2, Section 2.3.4.
7 2027 is cost of service amount. Subsequent years escalated by the Price Cap Index (line 9).
8 Per Ex. H1-2-1, Table 1, line 21.

Table 2
Calculation of Capital Factor for Regulated Hydroelectric Facilities
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation**	Ex. F4-1-1 Table 1, line 10	215.4	228.4	249.6	263.6	271.7
2	**Cost of Debt**	Note 2	201.5	222.3	254.3	272.9	286.9
3	**Return on Equity**	Note 2	432.8	458.9	512.3	543.4	568.8
4	**Income Taxes**	Ex. F4-2-1 Table 3b, line 24	27.3	70.3	87.6	101.6	110.7
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	876.9	979.9	1,103.8	1,181.5	1,238.1
6	**Regulated Hydroelectric Stretch Factor Capital Related Revenue Requirement Adjustment**	0.15% * line 5 (cumulative)		1.5	3.1	4.9	6.8
7	**Capital Related Revenue Requirement after Stretch**	line 5 - line 6	876.9	978.5	1,100.7	1,176.6	1,231.4
8	**Capital Afforded through (I-X) Adjustment** (assuming Custom Capital Factor in preceding years)	(line 8_{t-1} + line 9_{t-1}) x (I-X)	876.9	906.2	1,011.1	1,137.5	1,215.9
9	**Capital Related Revenue Requirement Shortfall**	line 7 - line 8	-	72.2	89.6	39.1	15.5
10	**Custom Capital Factor (C-Factor)**	line 9_t / line 14_{t-1}		4.3%	5.0%	2.0%	0.8%
11	**OM&A (excluding GRC)**	2028-2031: escalated by (I - X)	501.4	518.2	535.5	553.3	571.8
12	**GRC**	Note 3	352.2	352.2	352.2	352.2	352.2
13	**Other Revenues**	2028-2031: escalated by (I - X)	(62.2)	(64.3)	(66.5)	(68.7)	(71.0)
14	**Total Revenue Requirement**	line 7 + (lines 11 to 13)	1,668.3	1,784.5	1,921.9	2,013.5	2,084.4

Notes:

1 Per Ex. I1-1-1, Table 1.

2 Determination of cost of capital amounts included in the C-factor is based on the following:

Line No.	Description	Reference	2027	2028	2029	2030	2031
2a	Rate Base	Ex. B1-1-1, Table 1	9,135.1	9,687.1	10,814.1	11,471.1	12,007.4
2b	Short-Term Debt	Ex. C1-1-1 Tables 1-4	7.7	7.3	8.0	7.8	6.7
2c	Long-Term Debt	Ex. C1-1-1 Tables 1-4	193.8	215.1	246.3	265.1	280.2
2d	Common Equity	Ex. C1-1-1 Tables 1-4	432.8	458.9	512.3	543.4	568.8

3 The GRC Factor calculated below effectively fixes the underlying GRC amount recovered through payment amounts at the 2027 amount:

Line No.	Description	Reference	2027	2028	2029	2030	2031
3a	GRC Escalated by (I-X)	line 12 x (1+(I-X))	352.2	364.0	364.0	364.0	364.0
3b	Variance to Fixed GRC	line 12 less line 3a	-	(11.8)	(11.8)	(11.8)	(11.8)
3c	Variance as Percentage of Prior Year Revenue Requirement	line 3b, col. b / line 14, col. a	-	-0.7%	-0.7%	-0.6%	-0.6%

NUCLEAR PAYMENT AMOUNTS

1.0 PURPOSE

This evidence presents the blended payment amounts requested by OPG and DNNP LP for OPG's nuclear facilities and the DNNP facilities for 2027, 2028, 2029, 2030, and 2031.

2.0 PAYMENT AMOUNT

The Application is seeking approval of the following shaped payment amounts:

- $206.70/MWh for the nuclear facilities effective January 1, 2027;
- $192.42/MWh for the nuclear facilities effective January 1, 2028;
- $202.74/MWh for the nuclear facilities effective January 1, 2029;
- $199.16/MWh for the nuclear facilities effective January 1, 2030; and
- $219.60/MWh for the nuclear facilities effective January 1, 2031.

The basis for the requested payment amounts is presented in Ex. I1-3-1, Table 1.

Table 1
Payment Amounts - Combined Nuclear
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	Revenue Requirement - OPG Nuclear Facilities	1	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
2	Revenue Requirement - DNNP Facilities	2	301.0	378.8	404.9	559.3	1,042.0
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,363.8	4,636.2	5,081.9	5,441.7	6,779.6
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(500.0)	500.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement After Shaping Adjustment ($M)** (line 3 + line 4)		3,863.8	5,136.2	5,081.9	5,441.7	6,779.6
6	Production Forecast - OPG Nuclear Facilities	4	18.7	26.7	25.1	26.8	28.9
7	Production Forecast - DNNP Facilities	5	0.0	0.0	0.0	0.5	1.9
8	**Combined Nuclear Forecast Production (TWh)**		18.7	26.7	25.1	27.3	30.9
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)	6	206.70	192.42	202.74	199.16	219.60

Notes:
1 From Ex. I1-1-1 Table 2, line 26.
2 From Ex. I1-1-1, Table 2a, line 22.
3 The Application's payment amount shaping proposal is discussed in Ex. I1-3-2.
4 From Ex. E2-1-1 Table 1, line 3.
5 From Ex. E2-1-1 Table 1, line 4.
6 From Ex. I1-1-2 Table 2, line 4.

Table 2
Calculation of OPG Nuclear Facilities Stretch Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
	Darlington Nuclear OM&A Expenses						
1	Base OM&A	1		709.8	745.1	750.8	765.8
2	Project OM&A	2		54.2	53.9	51.6	54.3
3	Outage OM&A	3		112.7	219.1	121.6	115.8
4	Allocation of Corporate Costs	4		205.8	214.9	214.6	222.4
5	**Darlington Total OM&A Expenses Subject to Stretch Factor** (line 1 through line 4)			1,082.5	1,232.9	1,138.7	1,158.2
	Pickering Total Nuclear OM&A Expenses						
6	Base OM&A	5		140.9	153.4	166.0	459.7
7	Project OM&A	6		16.5	19.6	23.0	22.5
8	Outage OM&A	7		-	-	-	26.5
9	Pickering Cyclical Maintenance OM&A	8		160.9	168.9	169.9	106.6
10	Allocation of Corporate Costs	9		206.4	217.8	230.1	249.1
11	**Pickering Total OM&A Expenses Subject to Stretch Factor** (line 6 through line 10)			524.7	559.7	589.0	864.4
12	Asset Service Fees			73.9	89.5	99.0	99.4
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington and Operations & Project Support Capital Related Revenue Requirement						
13	Cost of Capital	10		318.8	337.9	391.3	457.1
14	Depreciation Expense	10		256.0	277.6	320.0	372.9
15	Income Tax Expense on Cost of Capital and Depreciation Expense	10		156.6	167.5	193.3	225.4
16	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 13 + line 14 + line 15)			731.4	783.1	904.6	1,055.4
	Pickering Capital Related Revenue Requirement						
17	Cost of Capital	11		24.1	29.3	45.0	59.4
18	Depreciation Expense	11		26.6	26.8	34.4	41.6
19	Income Tax Expense on Cost of Capital and Depreciation Expense	11		14.3	15.5	21.5	27.0
20	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 18 + line 19 + line 20)			65.0	71.6	100.9	128.1
21	Income Tax Expense- Capital Cost Allowance	13		(159.4)	(193.6)	(207.4)	(226.2)
22	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 12 + line 16 + line 20 + line 21)			2,318.1	2,543.1	2,624.8	3,079.4
23	OPG Nuclear Facilities Stretch Factor	12		0.30%	0.30%	0.30%	0.30%
24	**OPG Nuclear Facilities Stretch Factor Revenue Requirement Adjustment ($M)** (line 22_t * line 23_t) + line 24_{t-1}	14		**7.0**	**14.6**	**22.5**	**31.7**

Notes:

Refer to Table 2a

Table 2a
Notes to Ex. I1-3-1 Table 2

Notes:

1 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(a); Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(a); Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(a); Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(a).

2 From Ex. F2-3-1, Table 1: line 1 + line 3a + line 3d.
3 From Ex. F2-4-1,Table 1, line 3.
4 From Ex. F3-1-1, Table 3a, line 10.

5 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(b). Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(b). Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(b). Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(b).

6 From Ex. F2-3-1, Table 1: line 2 + line 3b + line 3e.
7 From Ex. F2-4-1_Table 1, line 6.
8 From Ex. F2-4-1, Table 1, line 14.
9 From Ex. F3-1-1, Table 3b, line 10.
10 Cost of capital component of Darlington and Operations & Project Support Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
10a	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), lines 13 and 20 less Ex. B3-4-1 Table 2, col. (f), lines 37 and 44. Less line 10b. 2029: Ex. B3-3-1, Table 2, col. (f), lines 25 and 32 less Ex. B3-4-1 Table 2, col. (f), lines 49 and 56. Less line 10b. 2030: Ex. B3-3-1, Table 2, col. (f), lines 37 and 44 less Ex. B3-4-1 Table 2, col. (f), lines 61 and 68. Less line 10b. 2031: Ex. B3-3-1, Table 2, col. (f), lines 49 and 56 less Ex. B3-4-1 Table 2, col. (f), lines 73 and 80. Less line 10b.		4,447.4	4,687.9	5,426.9	6,347.4
10b	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which common equity is subject to return at long-term debt rate.		127.1	114.6	103.7	95.5
10c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		210.7	222.1	257.1	300.7
10d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		3.2	2.9	2.7	2.5
10e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		105.0	112.9	131.6	154.0
10f	Total Cost of Capital (lines 10c + 10d + 10e)		**318.8**	**337.9**	**391.3**	**457.1**
10g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 37 & 44; lines 49 & 56; lines 61 & 68; lines 73 & 80)		256.0	277.6	320.0	372.9
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		469.8	502.6	579.8	676.1
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**156.6**	**167.5**	**193.3**	**225.4**

11 Cost of capital component of Pickering Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

11a	Pickering GS Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), line 17 less Ex. B3-4-1 Table 2, col. (f), line 41. Less line 11b. 2029: Ex. B3-3-1, Table 2, col. (f), line 29 less Ex. B3-4-1 Table 2, col. (f), line 53. Less line 11b. 2030: Ex. B3-3-1, Table 2, col. (f), line 41 less Ex. B3-4-1 Table 2, col. (f), line 65. Less line 11b. 2031: Ex. B3-3-1, Table 2, col. (f), line 53 less Ex. B3-4-1 Table 2, col. (f), line 77. Less line 11b.		343.2	412.9	632.4	833.5
11b	Pickering GS Net Fixed Asset Rate Base for which Common Equity is Subject to Return at Long-Term Debt Rate.		-	-	-	-
11c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		16.3	19.6	30.0	39.5
11d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		-	-	-	-
11e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		7.9	9.7	15.0	19.9
11f	Total Cost of Capital (lines 10c + 10d + 10e)		**24.1**	**29.3**	**45.0**	**59.4**
11g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 41, 53, 65, 77)		**26.6**	**26.8**	**34.4**	**41.6**
11h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		42.8	46.4	64.4	81.1
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**14.3**	**15.5**	**21.5**	**27.0**

12 Per Ex. A1-3-2, Section 3.2.1.

13 Income tax component of CCA-related revenue requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
(a)	Capital Cost Allowance (Ex. F4-2-1 Table 3d, line 15 less DRP and PRP amounts per Ex. F4-2-1 Table 3f Note 3)		(478.2)	(580.9)	(622.3)	(678.5)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))		**(159.4)**	**(193.6)**	**(207.4)**	**(226.2)**

14 The nuclear stretch factor revenue requirement adjustment can be further broken down as follows:

		2027	2028	2029	2030	2031
14a	OM&A Stretch Factor Adjustment ((line 5 + line 11 + line 12) * line 23)		5.0	10.7	16.2	22.5
14b	Capital-related Stretch Factor Adjustment (line 16 + line 20 + line 21) * line 23)		1.9	3.9	6.3	9.2
14c	Total Nuclear Stretch Factor Revenue Requirement Adjustment (line 14a + line 14b)		7.0	14.6	22.5	31.7

Table 1
Payment Amounts - Combined Nuclear
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	Revenue Requirement - OPG Nuclear Facilities	1	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
2	Revenue Requirement - DNNP Facilities	2	301.0	378.8	404.9	559.3	1,042.0
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,363.8	4,636.2	5,081.9	5,441.7	6,779.6
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(500.0)	500.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement After Shaping Adjustment ($M)** (line 3 + line 4)		3,863.8	5,136.2	5,081.9	5,441.7	6,779.6
6	Production Forecast - OPG Nuclear Facilities	4	18.7	26.7	25.1	26.8	28.9
7	Production Forecast - DNNP Facilities	5	0.0	0.0	0.0	0.5	1.9
8	**Combined Nuclear Forecast Production (TWh)**		18.7	26.7	25.1	27.3	30.9
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)	6	206.70	192.42	202.74	199.16	219.60

Notes:
1 From Ex. I1-1-1 Table 2, line 26.
2 From Ex. I1-1-1, Table 2a, line 22.
3 The Application's payment amount shaping proposal is discussed in Ex. I1-3-2.
4 From Ex. E2-1-1 Table 1, line 3.
5 From Ex. E2-1-1 Table 1, line 4.
6 From Ex. I1-1-2 Table 2, line 4.

Numbers may not add due to rounding.

Table 2
Calculation of OPG Nuclear Facilities Stretch Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
	Darlington Nuclear OM&A Expenses						
1	Base OM&A	1		709.8	745.1	750.8	765.8
2	Project OM&A	2		54.2	53.9	51.6	54.3
3	Outage OM&A	3		112.7	219.1	121.6	115.8
4	Allocation of Corporate Costs	4		205.8	214.9	214.6	222.4
5	**Darlington Total OM&A Expenses Subject to Stretch Factor** (line 1 through line 4)			1,082.5	1,232.9	1,138.7	1,158.2
	Pickering Total Nuclear OM&A Expenses						
6	Base OM&A	5		140.9	153.4	166.0	459.7
7	Project OM&A	6		16.5	19.6	23.0	22.5
8	Outage OM&A	7		-	-	-	26.5
9	Pickering Cyclical Maintenance OM&A	8		160.9	168.9	169.9	106.6
10	Allocation of Corporate Costs	9		206.4	217.8	230.1	249.1
11	**Pickering Total OM&A Expenses Subject to Stretch Factor** (line 6 through line 10)			524.7	559.7	589.0	864.4
12	Asset Service Fees			73.9	89.5	99.0	99.4
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington and Operations & Project Support Capital Related Revenue Requirement						
13	Cost of Capital	10		318.8	337.9	391.3	457.1
14	Depreciation Expense	10		256.0	277.6	320.0	372.9
15	Income Tax Expense on Cost of Capital and Depreciation Expense	10		156.6	167.5	193.3	225.4
16	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 13 + line 14 + line 15)			731.4	783.1	904.6	1,055.4
	Pickering Capital Related Revenue Requirement						
17	Cost of Capital	11		24.1	29.3	45.0	59.4
18	Depreciation Expense	11		26.6	26.8	34.4	41.6
19	Income Tax Expense on Cost of Capital and Depreciation Expense	11		14.3	15.5	21.5	27.0
20	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 18 + line 19 + line 20)			65.0	71.6	100.9	128.1
21	Income Tax Expense- Capital Cost Allowance	13		(159.4)	(193.6)	(207.4)	(226.2)
22	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 12 + line 16 + line 20 + line 21)			2,318.1	2,543.1	2,624.8	3,079.4
23	OPG Nuclear Facilities Stretch Factor	12		0.30%	0.30%	0.30%	0.30%
24	**OPG Nuclear Facilities Stretch Factor Revenue Requirement Adjustment ($M)** (line 22_t * line 23_t) + line 24_{t-1}	14		**7.0**	**14.6**	**22.5**	**31.7**

Notes:

Refer to Table 2a

Table 2a
Notes to Ex. I1-3-1 Table 2

Notes:
1 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(a); Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(a); Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(a); Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(a).
2 From Ex. F2-3-1, Table 1: line 1 + line 3a + line 3d.
3 From Ex. F2-4-1,Table 1, line 3.
4 From Ex. F3-1-1, Table 3a, line 10.
5 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(b). Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(b). Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(b). Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(b).
6 From Ex. F2-3-1, Table 1: line 2 + line 3b + line 3e.
7 From Ex. F2-4-1_Table 1, line 6.
8 From Ex. F2-4-1, Table 1, line 14.
9 From Ex. F3-1-1, Table 3b, line 10.
10 Cost of capital component of Darlington and Operations & Project Support Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
10a	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), lines 13 and 20 less Ex. B3-4-1 Table 2, col. (f), lines 37 and 44. Less line 10b. 2029: Ex. B3-3-1, Table 2, col. (f), lines 25 and 32 less Ex. B3-4-1 Table 2, col. (f), lines 49 and 56. Less line 10b. 2030: Ex. B3-3-1, Table 2, col. (f), lines 37 and 44 less Ex. B3-4-1 Table 2, col. (f), lines 61 and 68. Less line 10b. 2031: Ex. B3-3-1, Table 2, col. (f), lines 49 and 56 less Ex. B3-4-1 Table 2, col. (f), lines 73 and 80. Less line 10b.		4,447.4	4,687.9	5,426.9	6,347.4
10b	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which common equity is subject to return at long-term debt rate.		127.1	114.6	103.7	95.5
10c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		210.7	222.1	257.1	300.7
10d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		3.2	2.9	2.7	2.5
10e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		105.0	112.9	131.6	154.0
10f	Total Cost of Capital (lines 10c + 10d + 10e)		**318.8**	**337.9**	**391.3**	**457.1**
10g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 37 & 44; lines 49 & 56; lines 61 & 68; lines 73 & 80)		256.0	277.6	320.0	372.9
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		469.8	502.6	579.8	676.1
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**156.6**	**167.5**	**193.3**	**225.4**

11 Cost of capital component of Pickering Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
11a	Pickering GS Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), line 17 less Ex. B3-4-1 Table 2, col. (f), line 41. Less line 11b. 2029: Ex. B3-3-1, Table 2, col. (f), line 29 less Ex. B3-4-1 Table 2, col. (f), line 53. Less line 11b. 2030: Ex. B3-3-1, Table 2, col. (f), line 41 less Ex. B3-4-1 Table 2, col. (f), line 65. Less line 11b. 2031: Ex. B3-3-1, Table 2, col. (f), line 53 less Ex. B3-4-1 Table 2, col. (f), line 77. Less line 11b.		343.2	412.9	632.4	833.5
11b	Pickering GS Net Fixed Asset Rate Base for which Common Equity is Subject to Return at Long-Term Debt Rate.		-	-	-	-
11c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		16.3	19.6	30.0	39.5
11d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		-	-	-	-
11e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		7.9	9.7	15.0	19.9
11f	Total Cost of Capital (lines 10c + 10d + 10e)		**24.1**	**29.3**	**45.0**	**59.4**
11g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 41, 53, 65, 77)		**26.6**	**26.8**	**34.4**	**41.6**
11h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		42.8	46.4	64.4	81.1
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**14.3**	**15.5**	**21.5**	**27.0**

12 Per Ex. A1-3-2, Section 3.2.1.

13 Income tax component of CCA-related revenue requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
(a)	Capital Cost Allowance (Ex. F4-2-1 Table 3d, line 15 less DRP and PRP amounts per Ex. F4-2-1 Table 3f Note 3)		(478.2)	(580.9)	(622.3)	(678.5)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))		**(159.4)**	**(193.6)**	**(207.4)**	**(226.2)**

14 The nuclear stretch factor revenue requirement adjustment can be further broken down as follows:

		2027	2028	2029	2030	2031
14a	OM&A Stretch Factor Adjustment ((line 5 + line 11 + line 12) * line 23)		5.0	10.7	16.2	22.5
14b	Capital-related Stretch Factor Adjustment (line 16 + line 20 + line 21) * line 23)		1.9	3.9	6.3	9.2
14c	Total Nuclear Stretch Factor Revenue Requirement Adjustment (line 14a + line 14b)		7.0	14.6	22.5	31.7

PAYMENT AMOUNT SHAPING

1.0 PURPOSE

This evidence sets out the Application's proposal for shaping payment amounts during the 2027-2031 IR term.

2.0 OVERVIEW

OPG proposes a payment amount shaping approach intended to help manage the 2027 ratepayer impacts, while balancing the company's financing needs over the 2027-2031 period. To enable payment amount shaping, the Application proposes to establish a Payment Amount Shaping Deferral Account ("PASDA") to record the difference between: (1) OPG's total annual nuclear revenue requirement approved by the OEB; and (2) the portion of that revenue requirement in (1) that is used in connection with setting the nuclear payment amounts in each year.[1]

For the 2027-2031 IR term, OPG proposes to defer $500M of its proposed 2027 nuclear revenue requirement to 2028, with resulting PASDA entries[2] of $500M in 2027, $(500)M in 2028, $0M in 2029, $0M in 2030, and $0M in 2031 and resulting weighted average payment amounts ("WAPA")[3] of $110.03/MWh in 2027, $118.62/MWh in 2028, $123.42/MWh in 2029, $125.83/MWh in 2030, and $141.02/MWh in 2031. This proposal is consistent with customer feedback received during OPG's customer engagement (See Attachment 1).

The estimated average residential customer bill impact of the weighted average payment amounts proposed in this Application inclusive of the payment amount shaping proposal is 2.4% annually or approximately $3.40 on a typical monthly residential customer bill each year.[4]

[1] Ex. H1-1-1 Section 7.4.
[2] Ex. I1-3-1 Table 1, line 2.
[3] Ex. I1-1-2 Table 2, line 9.
[4] Ex. I1-1-2 Table 1, lines 4 and 5, col. (f).

Section 3.0 describes the calculation of the WAPA and the resulting WAPA and bill impacts in this Application, before rate shaping. Section 4.0 sets out the Application's rate shaping proposal and OPG's customer engagement efforts.

3.0 WEIGHTED AVERAGE PAYMENT AMOUNTS AND BILL IMPACTS

3.1 Calculation of the Weighted Average Payment Amount

OPG determines WAPA for a year through the following formula:

$$\frac{((BNPA + BNPR) \times TNPF) + ((HPA + HPR) \times HPF)}{(TNPF + HPF)}$$

BNPA (**Blended Nuclear Payment Amount**) is the pre-shaping blended payment amount for the year in respect of the OPG nuclear facilities and the DNNP facilities[5]

BNPR (**Blended Nuclear Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances recorded in the deferral accounts and variance accounts established for the OPG nuclear facilities and the DNNP facilities

TNPF (**Total Nuclear Production Forecast**) is the sum of the production forecasts for the year for the OPG nuclear facilities and the DNNP nuclear facilities

HPA (**Hydroelectric Payment Amount**) is the payment amount for the year in respect of OPG's prescribed hydroelectric facilities

HPR (**Hydroelectric Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances

[5] Further description of the blended payment amount can be found in Ex. A1-3-2, Section 3.1.

recorded in the deferral accounts and variance accounts established for OPG's prescribed hydroelectric facilities

HPF (**Hydroelectric Production Forecast**) is the production forecast for OPG's prescribed hydroelectric facilities for the year

3.2 WAPA and Bill Impacts without Shaping

This section lays out the WAPA and estimated customer bill impacts resulting from the revenue requirements and production forecasts proposed in this Application.

Blended Nuclear Payment Amount ("BNPA"):

The nuclear revenue requirements for OPG's nuclear facilities and the DNNP facilities proposed in this application are summarized in Chart 1 below and the production forecasts for OPG's nuclear facilities and the DNNP facilities are summarized in Chart 2 below.

Chart 1 - Nuclear Revenue Requirements Before Shaping[6]

	2027	**2028**	**2029**	**2030**	**2031**
OPG Nuclear Revenue Requirement Net of Stretch Factor ($M)	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
DNNP Revenue Requirement ($M)	301.0	378.8	404.9	559.3	1,042.0

Chart 2 - Nuclear Production Forecasts[7]

	2027	**2028**	**2029**	**2030**	**2031**
OPG Nuclear Production Forecast (TWh)	18.7	26.7	25.1	26.8	28.9
DNNP Production Forecast (TWh)	0.0	0.0	0.0	0.5	1.9

Based on the information provided in Chart 1 and Chart 2, the proposed pre-shaping BNPA amounts are $233.45/MWh in 2027, $173.69/MWh in 2028, $202.74/MWh in 2029, $199.16/MWh in 2030, and $219.60/MWh in 2031.

[6] Ex. I1-3-1 Table 1, lines 1 and 2.
[7] Ex. E2-1-1 Table 1, line 3 and line 4.

Hydroelectric Payment Amount (“HPA”): Per Ex. I1-2-1 Table 1, line 11, the proposed HPA is $51.39/MWh in 2027. Final payment amounts beyond 2027 will be determined annually using the approved ratemaking methodology, proposed in Ex. A1-3-2. The illustrative hydroelectric payment amounts calculated using the proposed methodology and included in Ex. I1-2-1 Table 1 are $54.97/MWh in 2028, $59.20/MWh in 2029, $62.02/MWh in 2030, and $64.21/MWh in 2031. These illustrative HPAs are based on the proposed Gross Revenue Charge Factor, Custom Capital Factor, Stretch Factor, and the most recently published I Factor, to be updated annually.

Blended Nuclear Payment Rider (“BNPR”) and Hydroelectric Payment Rider (“HPR”): Per Ex. H1-2-1, OPG is requesting recovery or repayment of certain audited December 31, 2024 balances in the deferral and variance accounts, adjusted for 2025-2026 amortization amounts approved in EB-2020-0290 and EB-2023-0336, through nuclear payment riders and hydroelectric payment riders over the January 1, 2027 to December 31, 2031 period. The proposed blended nuclear payment rider[8] is $7.19/MWh in 2027, $5.04/MWh in 2028, $5.36/MWh in 2029, $2.48/MWh in 2030, and $2.19/MWh in 2031. The proposed hydroelectric payment rider[9] is $(1.17)/MWh in 2027, $(1.17)/MWh in 2028, $(1.17)/MWh in 2029, $0.00/MWh in 2030, and $0.00/MWh in 2031.

Determination of WAPA: Chart 3 lays out the calculation of WAPA absent payment amount shaping, based on the proposals in this Application.

[8] Ex. H1-2-1, Table 2, Line 34
[9] Ex. H1-2-1, Table 1, Line 21.

Chart 3 – Determination of WAPA

Line No.	Description	2027	2028	2029	2030	2031
1.	**BNPA ($/MWh)**	$233.45/MWh	$173.69/MWh	$202.74/MWh	$199.16/MWh	$219.60/MWh
2.	**BNPR ($/MWh)**	$7.19/MWh	$5.04/MWh	$5.36/MWh	$2.48/MWh	$2.19/MWh
3.	**TNPF (TWh)**	18.7TWh	26.7TWh	25.1TWh	27.3TWh	30.9TWh
4.	**HPA ($/MWh)**[10]	$51.39/MWh	$54.97/MWh	$59.20/MWh	$62.02/MWh	$64.21/MWh
5.	**HPR ($/MWh)**	$(1.17)/MWh	$(1.17)/MWh	$(1.17)/MWh	$0.00/MWh	$0.00/MWh
6.	**HPF (TWh)**	32.5TWh	32.5TWh	32.5TWh	32.5TWh	32.5TWh
7.	**WAPA ($/MWh)** Pre-shaping	$119.80/MWh	$110.17/MWh	$123.42/MWh	$125.83/MWh	$141.02/MWh
8.	**WAPA (% y/y change)**	54.1%	-8.0%	12.0%	2.0%	12.1%
9.	**Typical Residential Monthly Bill Impact (%)**[11]	7.3%	-1.9%	2.6%	0.5%	3.3%

The year-over-changes in WAPA (line 8) and typical residential consumer residential monthly bills (line 9) show that the highest increase is in 2027, followed by a decrease in 2028 and increases in 2029, 2030, and 2031.

4.0 PAYMENT AMOUNT SHAPING PROPOSAL AND CUSTOMER ENGAGEMENT

To help manage the 2027 customer bill impacts and the associated volatility in year-over-year changes, OPG proposes to defer recovery of a portion of its 2027 nuclear revenue requirement to subsequent years in the IR term.

[10] Regulated hydroelectric payment amounts beyond 2027 are for illustrative purposes only.
[11] Further discussion on OPG's methodology for determining the impact of proposed payment amounts and payment riders on a typical residential electricity consumer monthly bill is found in Ex. I1-1-2.

4.1 Payment Amount Shaping Criteria

In determining the shaping amounts in each year, the Application was guided by two principles: customer bill impact and financial viability.

Customer Bill Impact: The primary objective of the payment amount shaping approach is to reduce the 2027 customer bill impact, and this is accomplished by deferring recovery of $500M of OPG's proposed nuclear revenue requirement from 2027. As a secondary objective, the analysis considered the trajectory of bill impacts over the remaining four years in the 2027-2031 period. This is addressed by varying how the $500M deferred from 2027 is recovered over the remaining years in the IR term.

Financial Viability: As discussed in Ex. A2-2-1 Section 3.3, OPG closely monitors credit metrics used by rating agencies (S&P, Moody's and DBRS), as these metrics significantly influence assigned credit ratings, which in turn affect the cost and availability of debt financing. As OPG undertakes substantial capital investments in support of Ontario's energy needs, all three rating agencies' reports have identified increasing pressure on the credit metrics as a risk.

In considering payment amount shaping options, OPG determined that deferring recovery of more than approximately $500M from 2027 could adversely affect its key credit metrics. Maintaining the current credit ratings is important to OPG's ability to access effective debt financing and, thus, OPG did not consider payment amount shaping options that deferred recovery of more than $500M from 2027.[12]

4.2 Payment Amount Shaping Options

OPG considered three options for payment amount shaping, as summarized in Chart 4, below. Approach A is a status quo scenario with no shaping of proposed payment amounts. Approach B reduces recovery by $500M in 2027 and increases recovery by $500M in 2028. Approach C reduces recovery by $500M in 2027 and increases recovery by $250M in 2028, $50M in 2029,

[12] See Ex. A2-2-1, Section 3.3 for further discussion OPG's credit metrics and credit ratings.

and $200M in 2030. The figures are stated before interest costs that would be associated with the deferral.

Chart 4 – Estimated Residential Monthly Bill Impacts Under Payment Amount Shaping Options

Line No.	Scenario	2027	2028	2029	2030	2031
1	**Approach A**	$10.33 7.3%	$(2.74) -1.9%	$3.66 2.6%	$0.69 0.5%	$4.62 3.3%
2	**Approach B**	$7.93 5.6%	$2.44 1.7%	$1.33 0.9%	$0.69 0.5%	$4.62 3.3%
3	**Approach C**	$7.93 5.6%	$1.24 0.9%	$2.73 1.9%	$1.40 1.0%	$3.61 2.5%

OPG presented these scenarios to customers as part of a customer engagement process conducted by Innovative Research Group Inc. (“INNOVATIVE”), as discussed below in Section 4.3.[13]

4.3 Customer Engagement Feedback

OPG engaged INNOVATIVE to conduct a customer engagement process that included seeking feedback on OPG’s approach to payment amount shaping.

INNOVATIVE sought customer input on the value proposition that different payment amount shaping options present for customers. INNOVATIVE presented payment amount shaping as “[smoothing] out the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years’ rates”. The workbook presented customers with three illustrative scenarios with varying degrees of shaping. These scenarios were generally aligned with those presented in Chart 4 above.

[13] In the customer engagement process, these payment amount shaping scenarios were presented in terms of the portion of a monthly bill paid to OPG over the period rather than in terms of the bill impact dollars and percentages shown in Chart 4.

The results of the customer engagement survey show that a plurality of customers supported at least some degree of rate shaping, with a combined 48% of panellists preferring Approach B or C.[14] Managing the volatility present in the pre-shaping payment amounts comes at a cost. In providing additional feedback in the customer engagement survey, the two most common types of responses related to concerns about future interest costs, and increases in costs more generally.[15] Customer preferences are discussed further in the INNOVATIVE report, filed as Attachment 1 to this schedule.

The Application's payment amount shaping proposal considered these customer preferences, while also balancing the Customer Bill Impact and Financial Viability criteria outlined in Section 4.1.

4.4 Payment Amount Shaping Proposal

The Application proposes Approach B, as it best reflects customer preferences collected through the customer engagement process as summarized above. This proposal helps to manage the 2027 increase and results in a lower amount of interest recorded to the PASDA as compared to Approach C.

Based on this analysis, the proposed nuclear payment amounts presented in Ex. I1-3-1 have been determined based on Approach B. The Application therefore proposes to defer the collection of $500M in OPG's nuclear revenue requirement from 2027 to 2028, as shown in Ex. I-1-3-1, Table 1 and reproduced in Chart 5, below.

[14] Attachment 1, p. 20.
[15] *Ibid.*, p. 21.

Chart 5 - Proposed Combined Nuclear Revenue Requirement and Payment Amounts[16]

	2027	2028	2029	2030	2031
Proposed Combined Revenue Requirement Before Shaping ($M)	$4,363.8	$4,636.2	$5,081.9	$5,441.7	$6,779.6
OPG Revenue Requirement Shaping Adjustment ($M)	$(500.0)	$500.0	$0.0	$0.0	$0.0
Proposed Shaped Combined Revenue Requirement ($M)	$3,863.8	$5,136.2	$5,081.9	$5,441.7	$6,779.6
Total Nuclear Production Forecast (TWh)	18.7	26.7	25.1	27.3	30.9
Blended Nuclear Payment Amount After Shaping ($/MWh)	$206.70	$192.42	$202.74	$199.16	$219.60

[16] Includes OPG nuclear facilities and DNNP facilities.

LIST OF ATTACHMENTS

Attachment 1: *2025 Customer Engagement Report*, Innovative Research Group Inc.

INNOVATIVE
RESEARCH GROUP

Online Survey
2025 Customer Engagement Report

ONTARIO POWER GENERATION

November 2025

Introduction & Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client Ontario Power Generation Inc. (Ontario Power Generation or OPG) to help design, execute and document the results of OPG's customer engagement in support of its 2027 to 2031 rate application.

Unlike other utility rate applications in Ontario, much of OPG's plan and are determined as a matter of system planning and cannot be influenced by customer preferences. As such, this customer engagement survey focuses on 3 key principles:

1. Focus on customer, not company outcomes
2. Do not expect customers to be subject-matter experts
3. Provide customers with the necessary background/context to make informed decisions

Method: A random sample of online panellists were invited to complete the survey from a set of partner panels based on the Lucid exchange platform. These partners are typically double opt-in survey panels, blended to manage potential skews in the data from a single source.

Sample Size: This survey was conducted online among a representative sample of n=2,524 (weighted to n=2,500) Ontarians, 18 years or older who at least share responsibility for paying their household electricity bill.

Field Dates: **November 12th to November 18th, 2025**

Weighting: Results are weighted by age, gender, region, and education to ensure that the overall sample's composition reflects that of the actual population according to Census data; in order to provide results that are intended to approximate a probability sample.

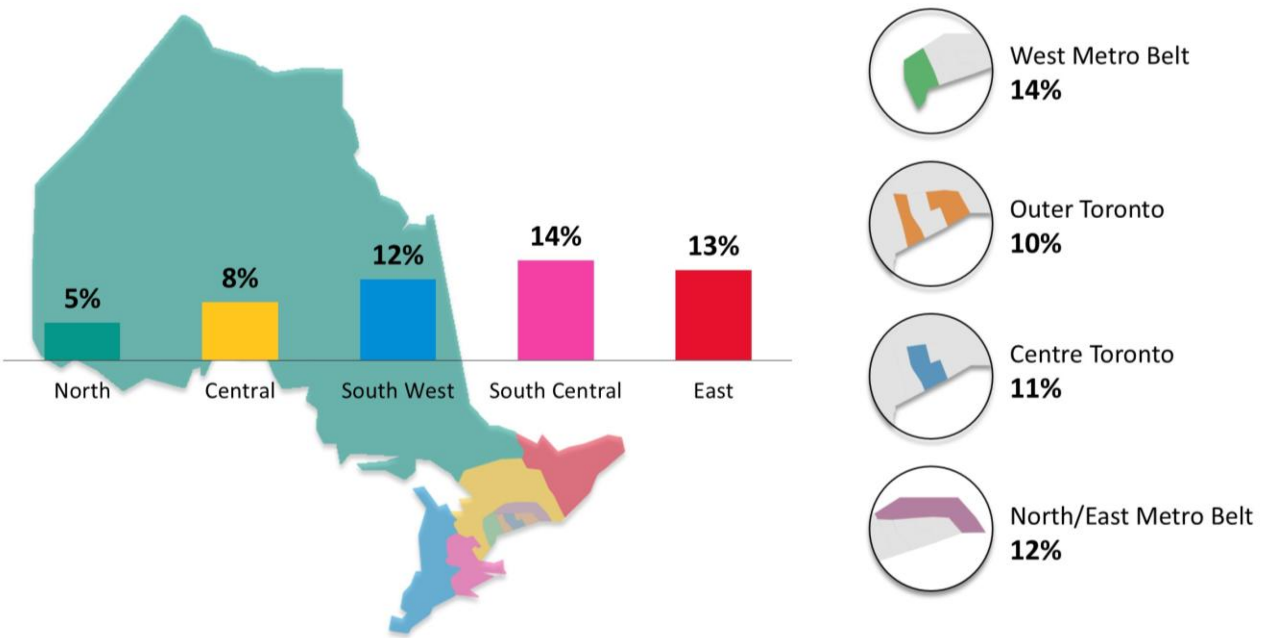
Margin of Error: This is a representative sample. However, since the online survey was not a random probability-based sample, a margin of error cannot be calculated. Statements about margins of sampling error or population estimates do not apply to most online panels.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Regional Segmentation

To ensure that the survey results are regionally representative of the Ontario population, respondents are categorized into 9 Ontario regions based on the first three characters of their postal code.

As shown below, the 9 regions are then further combined into 4 regions: **Toronto** (Outer Toronto + Centre Toronto), **Rest of GTA** (the Metro Belts), **South/West** (South West + South Central), and **North/East** (East + Central + North).



The table below summarizes the unweighted and weighted (in brackets) sample breakdown by age, gender, and region. Totals may not correspond with cell values as some respondents prefer to self-describe their gender. Weights are calculated based on all available information for a given respondent.

Region	Age-Gender						Total
	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+	
Toronto	70 (69)	100 (90)	109 (79)	99 (86)	75 (98)	75 (89)	528 (510)
Rest of GTA	87 (84)	135 (117)	140 (115)	92 (82)	98 (138)	101 (124)	653 (660)
South/West	114 (80)	117 (113)	162 (129)	66 (82)	86 (109)	118 (142)	665 (656)
North/East	83 (65)	113 (111)	175 (152)	76 (72)	100 (122)	131 (151)	678 (673)
Total	354 (298)	465 (430)	586 (475)	333 (321)	359 (467)	425 (505)	2,524 (2,500)

Understanding Segmentation

In addition to segmenting electricity customers based on where they reside in Ontario, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within and what is outside of OPG's influence or control.

Segmentation has been used throughout this report to look beyond the topline numbers to analyze the results for key segments:

Region: As mentioned earlier, the first three characters of a respondent's postal code are used to split Ontario ratepayers into one of four regions for analysis.

Bill Impact on Finances: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

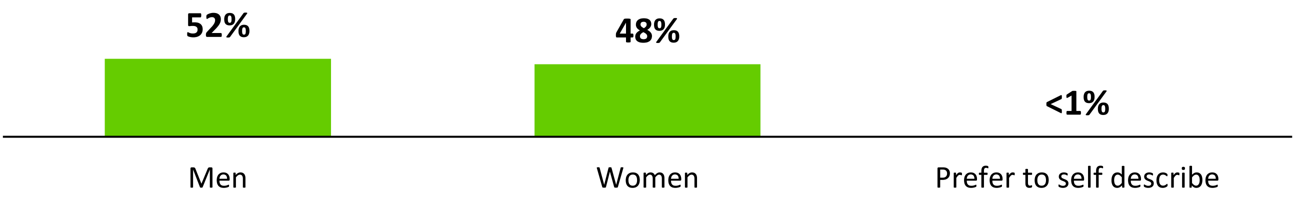
Vulnerable Consumers: Using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's Ontario Electricity Support Program (OESP) criteria.

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and digging deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know, overall, how many Ontarians are satisfied with OPG, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the OPG's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

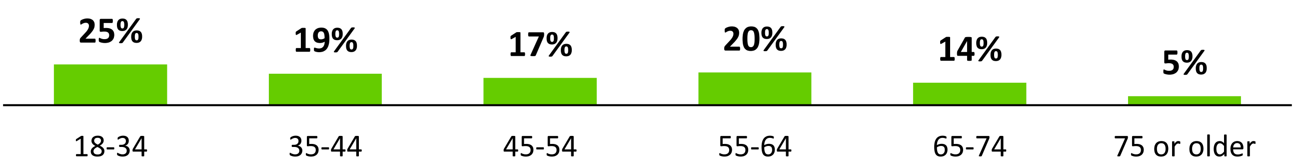
Demographic Breakdown

Q Gender



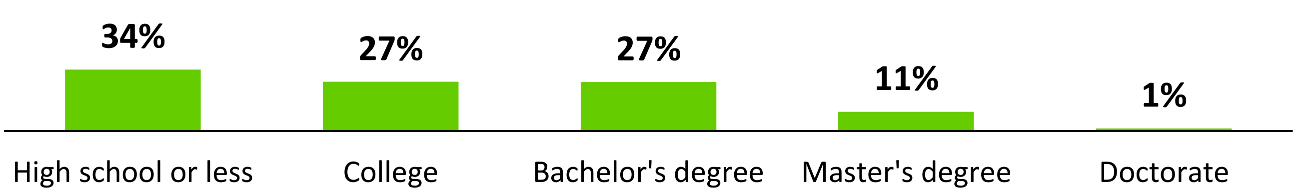
n=2,500

Q Age



n=2,500

Q Education



“Other” (1%) and “Prefer not to say” (<1%) not shown.

n=2,500

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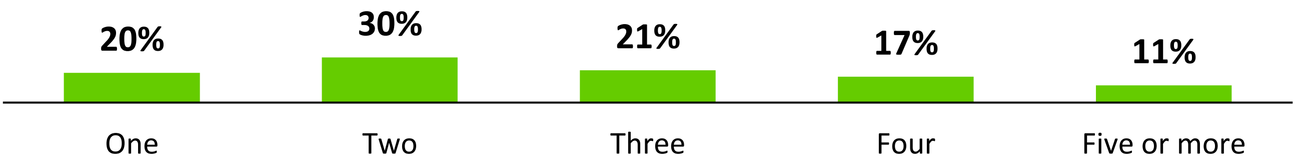
Demographic Breakdown

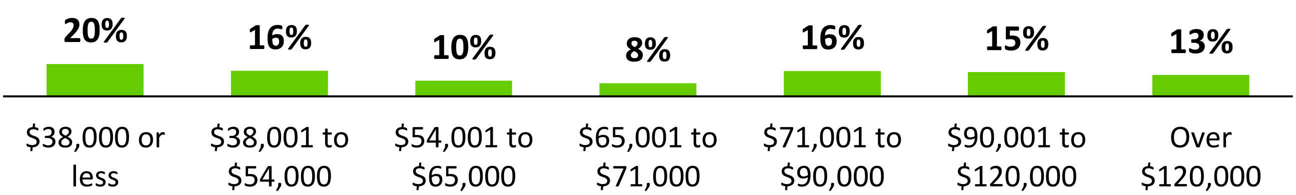
Q Household Size



“Prefer not to say” (<1%) not shown.

n=2,500

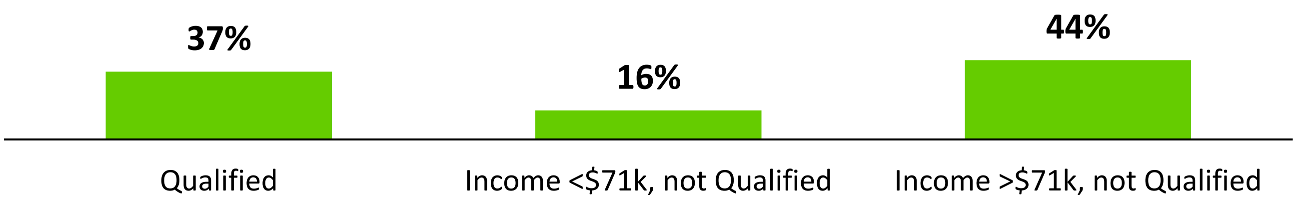
Q After Tax Household Income



“Prefer not to say” (3%) not shown.

n=2,500

Q **LEAP/OESP Qualification** (based on household size and income)



“Prefer not to say” (3%) not shown.

n=2,500

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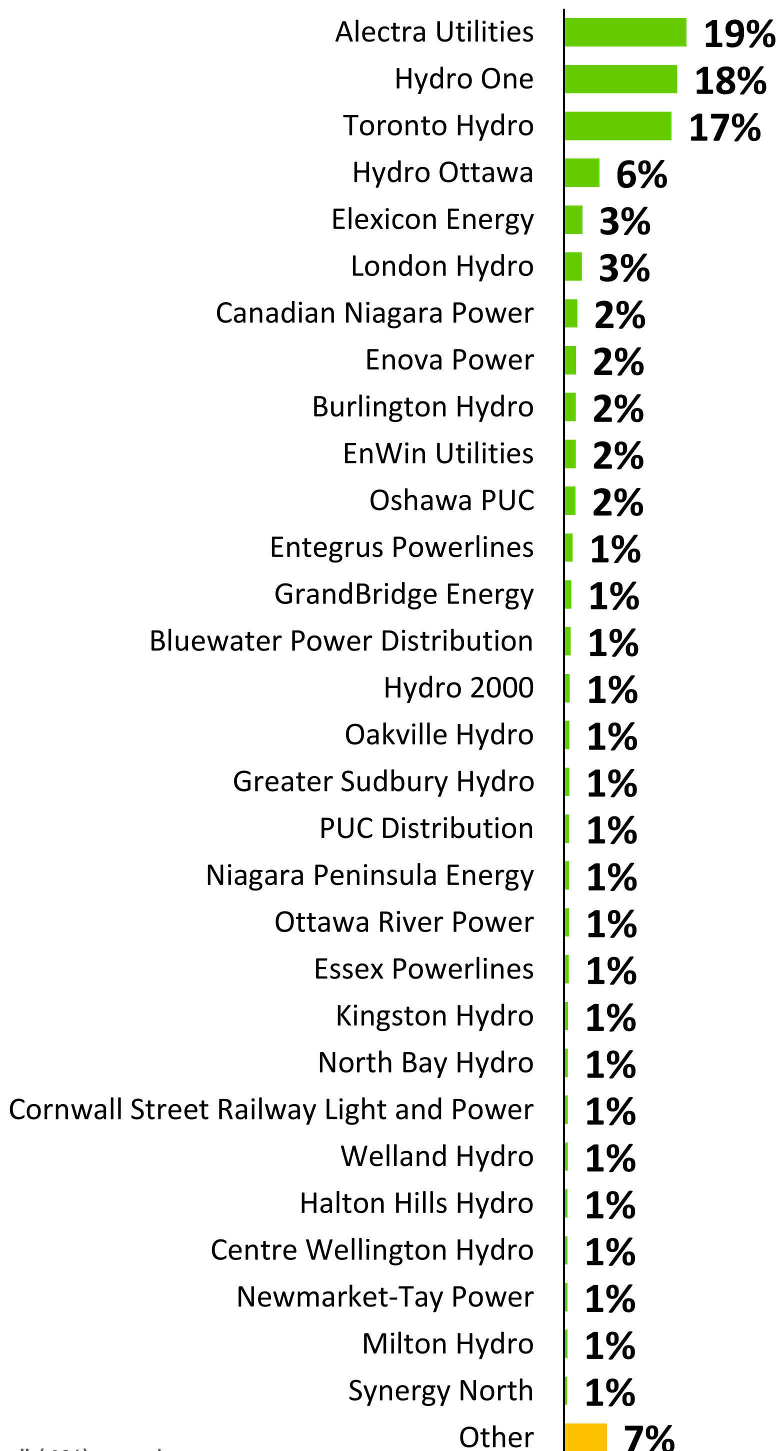
Demographic Breakdown

Q Electricity Provider



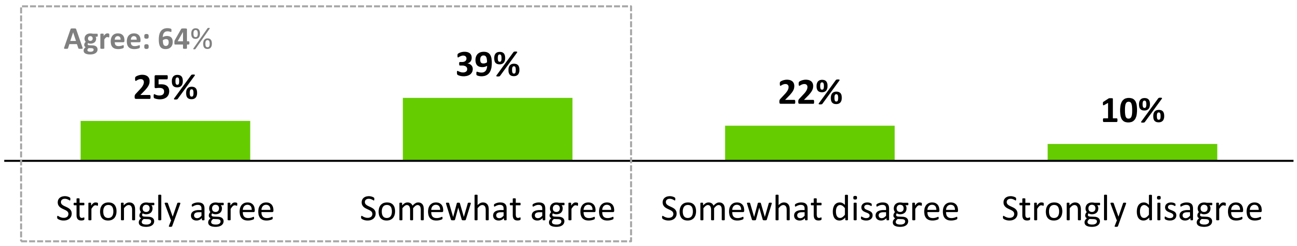
“Don’t know” (4%) not shown.

n=2,500

Environmental Controls

To what extent do you agree or disagree with the following statements?

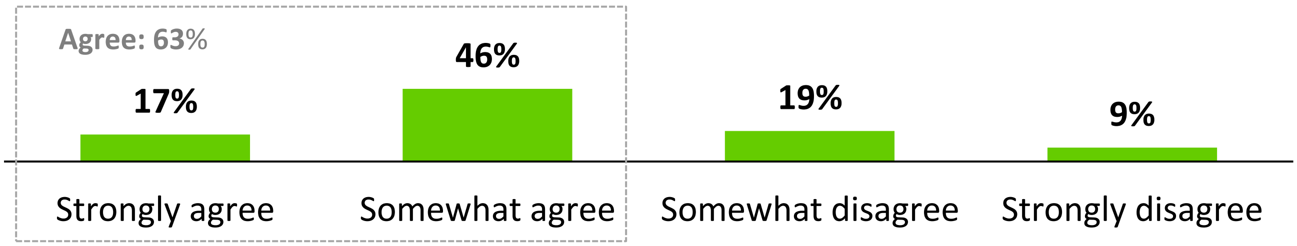
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=2,500

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (9%) not shown.

n=2,500

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Residential Ratepayers

Familiarity & Experience

Preamble:

Ontario Power Generation's (OPG), Ontario's largest electricity generator, is looking for input into choices that will impact the rates Ontarians pay for electricity.

The goal of this survey is to understand your point of view as a **residential** ratepayer.

Familiarity & Experience

Bill Familiarity

How much of your electricity bill goes to OPG?

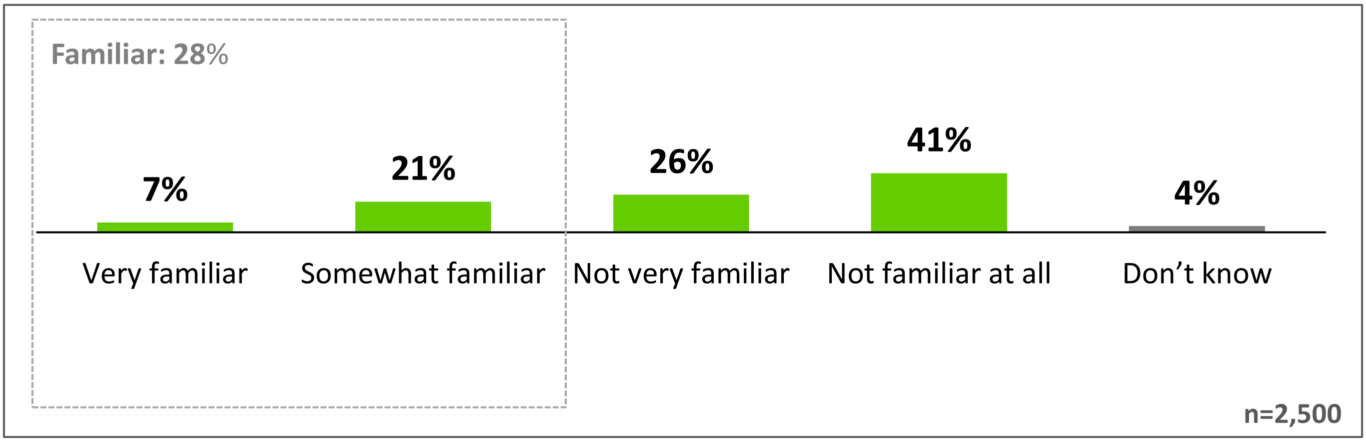
Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

As of **August 1st, 2025**, the average monthly bill for a typical residential customer consuming 750 kWh is about $135 after taxes and the Ontario Electricity Rebate.

On average, **about 15% or approximately $20 of the monthly electricity bill for a typical residential ratepayer** goes to OPG to pay for the power they generate. However, OPG's share of the bill depends on your consumption level and can be higher or lower in any given month.

The rest of the bill goes to pay for other generators, transmission companies, distribution companies, regulatory agencies, and government taxes.

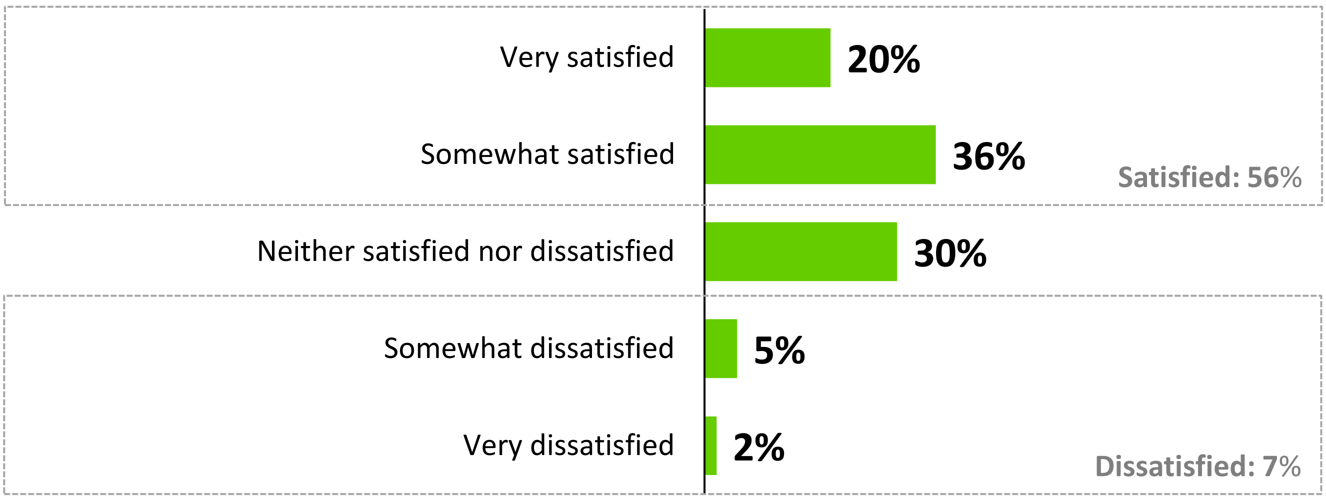
Q Before this survey, how familiar were you with the amount of your electricity bill that went to **OPG** for the generation of electricity?



Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?



"Don't know" (6%) not shown.

n=2,500

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Very satisfied	22%	20%	17%	21%
Somewhat satisfied	37%	41%	34%	34%
Neither	29%	27%	33%	32%
Somewhat dissatisfied	5%	5%	6%	4%
Very dissatisfied	1%	2%	2%	2%
Don't know	6%	4%	8%	8%
Satisfied (Very + Somewhat)	**59%**	**61%**	**51%**	**55%**
Dissatisfied (Very + Somewhat)	**6%**	**8%**	**8%**	**6%**

Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very satisfied	20%	17%	20%	22%	19%	22%
Somewhat satisfied	36%	34%	35%	40%	37%	35%
Neither	30%	33%	29%	27%	30%	31%
Somewhat dissatisfied	5%	5%	6%	4%	6%	3%
Very dissatisfied	2%	2%	3%	1%	3%	1%
Don't know	6%	8%	8%	4%	5%	8%
Satisfied (Very + Somewhat)	**56%**	**51%**	**55%**	**63%**	**56%**	**57%**
Dissatisfied (Very + Somewhat)	**7%**	**7%**	**9%**	**6%**	**9%**	**4%**

Familiarity & Experience

How can OPG do better?

Q Is there anything in particular that **OPG** could do better for you?

Response	%
Lower rates/reduce costs	11.7%
Improve communication or transparency	2.2%
No improvements needed/satisfied as is	1.8%
Help public better understand OPG's role/don't know what they do	1.4%
Increase investment in renewable energy/energy alternatives/green options	1.0%
Clearer information on bills/what goes to OPG	0.8%
Provide energy-saving incentives, programs, or guidance	0.7%
Upgrade/better maintain infrastructure	0.5%
Improve reliability	0.4%
Support low-income or vulnerable customers	0.2%
Improve environmental/wildlife protection practices	0.1%
Other	1.4%
None/Don’t know	77.9%

Note: Only responses >0.1% shown

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OPG's 2027-2031 Proposed Plan

Preamble:

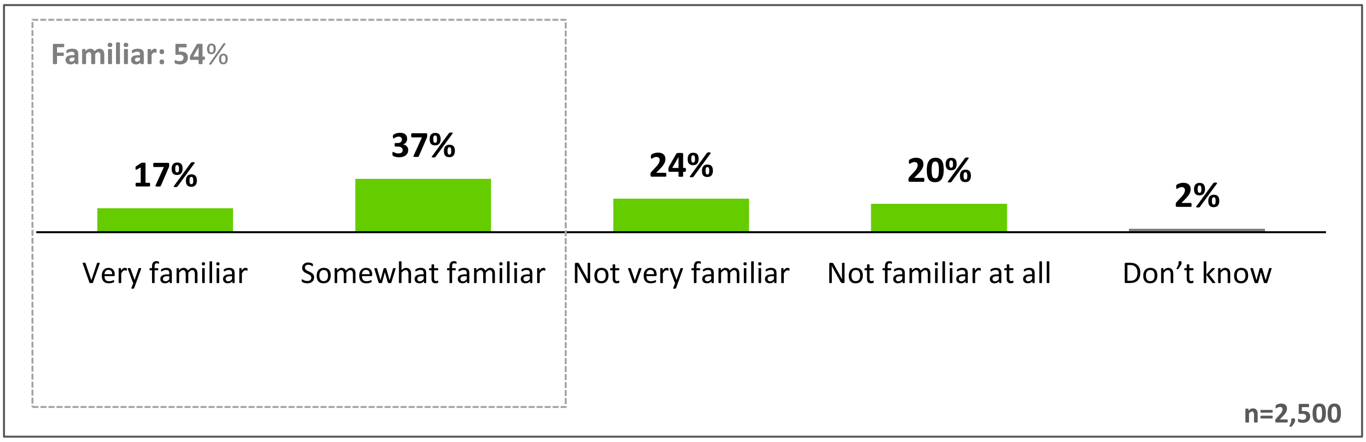
Now, let's talk about OPG's upcoming draft plan for 2027 to 2031.

OPG's 2027-2031 Proposed Plan

Familiarity with Future Electricity Demand

According to the **Independent Electricity System Operator (IESO)**, Ontario's independent electricity planning expert, annual electricity demand in the province is anticipated to grow significantly by 2050.

Q Before this survey, how familiar were you with the fact that Ontario's electricity demand is anticipated to increase in the next 25 years?



OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

As the company that is responsible for generating about half of Ontario's electricity, OPG's 2027 to 2031 plan will play an important role in meeting future electricity demand in Ontario.

OPG plans its investments in Ontario's electricity generating stations using a variety of inputs from Provincial system planners to independent experts and OPG's own engineers and asset managers.

However, much of OPG's plan and objectives are set by the Ontario government.

What's in OPG's plan for 2027 to 2031?

Hydroelectric power currently provides about 24 per cent of Ontario's electricity, and OPG's 2027 to 2031 plan includes significant investments in refurbishing hydroelectric generating stations across the province, which have an average age of 90 years. Costs associated with operating and investing in **<u>the hydroelectric fleet account for 30% of OPG's 2027-2031 plan</u>**.

OPG's two **nuclear generating stations** play a significant role in Ontario's energy mix. Darlington and Pickering Stations operate continuously to produce a steady and reliable supply of electricity, providing a foundation for the province's power needs. Costs associated with operating and investing in **<u>the nuclear fleet account for 65% of OPG's 2027-2031 plan</u>**.

A significant portion of OPG's 2027-2031 nuclear budget will fund the refurbishment of the Pickering nuclear plant, pending approvals. Once refurbished, this plant would continue to provide over 2,000 MW of baseload generating capacity for more than 30 years, the equivalent of powering approximately two million homes.

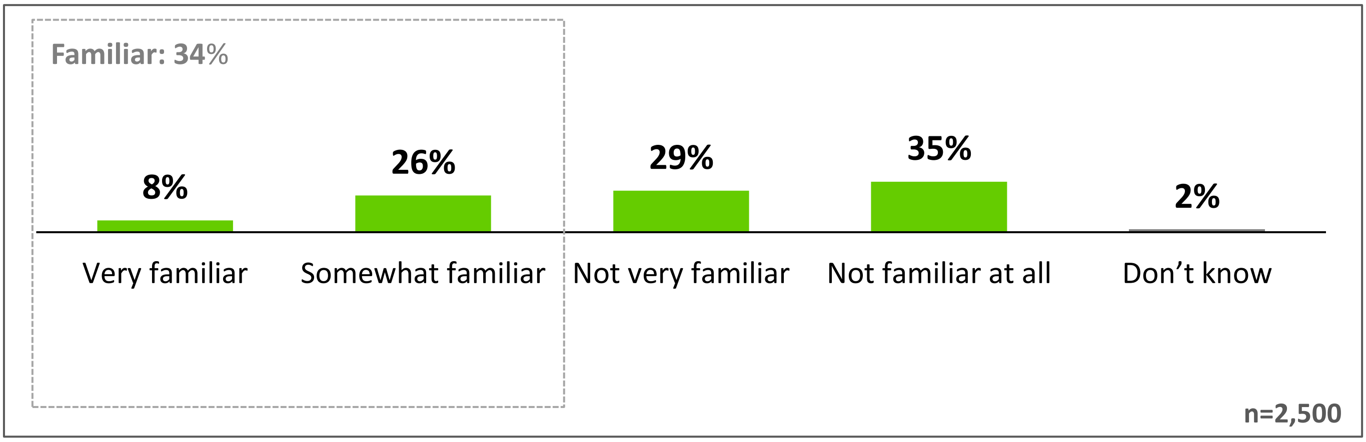
Finally, roughly **5%** of OPG's proposed 2027-2031 budget will fund development of the first grid-scale **Small Modular Reactor (SMR)** project in North America, if approved. An SMR is smaller and designed to simplify construction by using modular components, which can shorten construction times, reduce costs, and promote simplified and safe operation.

OPG's budget also goes toward meeting safety, legal, and regulatory requirements and all other aspects of running a large business.

OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

Q Before this survey, how familiar were you that **OPG** manages both a hydroelectric and nuclear fleet?



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Rate Shaping

Rate Shaping

Approaches to OPG's Proposed Plan

OPG has calculated the cost of their proposed plan.

Under its plan, depending on customer feedback, for a typical residential customer consuming 750 kWh per month, the portion of their monthly bill that goes to OPG could increase by up to $17, over the course of five years, from the start of 2027 to the end of 2031*, to fund the investments described on the preceding pages to maintain existing generation and build new projects to meet growing electricity demand which will support stable baseload generation.

OPG has developed three representative approaches for how these rate increases could potentially be rolled out over the 2027 to 2031 period. OPG is seeking customer feedback on these approaches before they submit their plan to the Ontario Energy Board, the provincial energy regulator, for review.

How much of a typical customer's monthly bill would go to OPG:

	2026	2027	2028	2029	2030	2031
Approach A	$20.00	$30.00	$27.00	$31.00	$32.00	$36.50
Approach B	$20.00	$27.50	$30.00	$31.50	$32.50	$37.00
Approach C	$20.00	$27.50	$29.00	$31.50	$33.50	$37.50

* Based on a point-in-time average for the typical residential customer with an average monthly bill of ~$135; annual changes are based on OPG impacts only, and do not consider the Ontario Electricity Rebate (OER).

Approach A represents the true cost of OPG's investments. This approach would result in a roughly $10 increase on the monthly bill in the first year of the plan (2027) and an average annual increase of about $2 in each of the following 4 years (2028-2031).

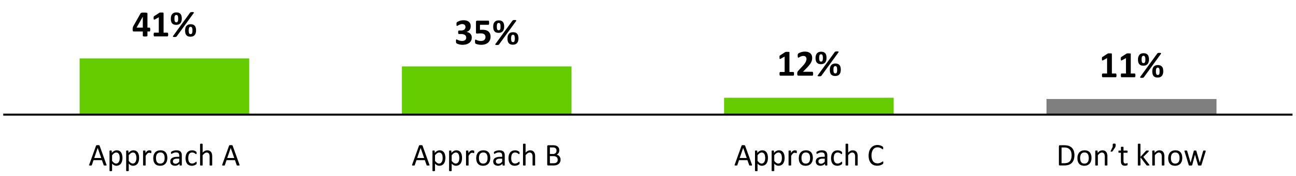
Approach B and **Approach C** "smooth out" the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years' rates.

In both **Approach B** and **Approach C,** to pay for the work in the short term, OPG would borrow more money instead of raising it through rates, incurring interest costs that would be paid by customers in later years.

Rate Shaping

Approaches to OPG's Proposed Plan

Q Which of the following approaches do you prefer?



n=2,500

Summary of Findings: Overall, 48% of Ontario electricity ratepayers prefer some degree of rate shaping (Approach B or C). 41% of electricity ratepayers prefer Approach A, which includes no rate shaping. The remaining 11% don't know which of the three approaches they prefer.

This sentiment is consistent across both region and among more financially vulnerable customers.

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Approach A	37%	44%	40%	42%
Approach B	36%	36%	37%	33%
Approach C	16%	12%	11%	11%
Don't know	11%	9%	12%	13%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Approach A	39%	39%	43%	39%	44%
Approach B	34%	35%	36%	37%	32%
Approach C	13%	12%	12%	13%	11%
Don't know	13%	13%	8%	10%	13%

Rate Shaping

Additional Feedback

Q Do you have any additional feedback on the approaches above that you would like to share?

Response	%
Support for upfront payment/concern about future interest costs (A)	4.4%
Increase is too high/lower costs	2.9%
No preference/all options are fine	1.9%
Preference for more gradual increase (B or C)	1.7%
Need for transparency/more information	1.5%
Affordability/cost of living concerns (low-income, seniors, fixed income)	0.8%
Distrust in OPG/perception of mismanagement/profit-driven motives	0.7%
OPG should find their own efficiencies/cost savings	0.6%
Confusion/difficulty understanding the approaches	0.1%
Include programs to support low-income/vulnerable households	0.1%
Other	1.9%
None/Don't know	83.3%

Note: Only responses >0.1% shown

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Ontario Power Generation. The conclusions drawn and opinions expressed are those of the authors.

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IESO SETTLEMENT PROCESS

1.0 PURPOSE

This evidence provides a description of the IESO settlement process used for OPG's regulated generation facilities and the DNNP facilities.

2.0 DESCRIPTION OF SETTLEMENT PROCESS

The general IESO settlement process is described in Chapter Nine of the Ontario Market Rules. OPG and DNNP LP understand that, based on the current IESO settlement process and the daily settlement frequency of the nuclear and regulated hydroelectric payment amounts, for revised payment amounts and riders to be reflected in the settlement and associated monthly invoice for all days in a given month, a final payment amounts order establishing the new payment amounts and riders should be issued by no later than the 20th of that month[1]. This timing is necessary for the IESO to update their systems and perform the settlement without retroactive adjustment through the IESO's Recalculated Settlement Statement ("RCSS") process. For example, for the invoice for the month of January to be fully based on revised payment amounts and riders, the payment amounts order should be issued on January 20th. If applicable, OPG and DNNP LP expect that the IESO's RCSS process would be used to adjust settlement amounts for the period[2] as of the effective date of the new payment amounts and riders that were not originally settled and invoiced using such payment amounts and riders in accordance with the process and timelines outline above.

The Application expects that all payments ordered in this Application will be made to OPG on behalf of itself and DNNP LP, consistent with direction provided in O. Reg. 53/05, s. 14(2)9:

[1] The exact date depends on the timing of the relevant invoice and the business days required by the IESO to update its settlement system.

[2] The Recalculated Settlement Statement process is subject to a 23-month limitation period as set out in the IESO's Market Rules, Ch. 9, Section 6.9.2.

In making a DNNP blended payment order, the Board shall require that payments be paid to Ontario Power Generation Inc., acting on its own behalf and as agent and nominee of the DNNP generator.