AMPCO Interrogatory #090

Interrogatory

Reference:
F1-1-1 p.4

Preamble:

During 2022, the Office of the Auditor General of Ontario (OAGO) conducted a Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations. In December 2024, the OAGO released a Follow-Up Report on its 2022 Value for Money Audit.

Question(s):

a) Please provide a copy of the OAGO's 2022 Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations.

b) Please provide a copy of the OAGO's December 2024 Follow-Up Report on its 2022 Value for Money Audit.

Response

a) The 2022 Value for Money Audit[1] of OPG's Management and Maintenance of Hydroelectric Generating Stations can be found at: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations

b) The 2024 Follow-Up on the 2022 Value for Money Audit[1] can be found at: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations

[1] As the Office of the Auditor General's reports are locked and cannot be edited, OPG is unable to file in accordance with the OEB's Regulatory Electronic Submission System Document Guide.

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

AMPCO Interrogatory #091

Interrogatory

Reference:
F1-1-1 p.5

Preamble:

Overall, for the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, OPG expects to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW.

Question(s):

a) For each of the 53 regulated hydroelectric refurbishment projects, please complete the following Table.

2027-2031 Hydroelectric Refurb Projects (capital)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE* $/MWh	Total Project Cost ($M)	Inservice $ 2027-2031
Total		1,500	50			

*Levelized Cost of Electricity (LCOE)

Response

For clarity, there are 39 refurbishment projects associated with 53 hydroelectric generating units at OPG's regulated hydroelectric facilities that are expected to come into service during the 2027-2031 period. Certain projects include multiple hydroelectric generating units.

The requested information regarding the 39 refurbishment projects is presented in Charts 1 to 4 below. Levelized cost of energy ("LCOE") analyses are not performed for refurbishment projects.

Chart 1 - Tier 1 Projects (Allocated)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Total Project Cost[1] ($M)	In-Service 2027-2031 ($M)
Abitibi Canyon GS, G1	83148	G1	69.5	0.0	54.7	46.8
R.H. Saunders GS, G16	86937	G16	61.7	4.5	49.3	38.7
Alexander GS, G2	86792	G2	12.6	0.0	49.7	43.5
Alexander GS, G1	82391	G1	12.6	0.0	45.9	42.0
Alexander GS, G3	86793	G3	12.6	0.0	43.6	40.0
Manitou Falls GS, G3	86860	G3	14.9	0.0	53.2	48.0
Sir Adam Beck 1 GS, G4	86570	G4	53.1	2.0	109.4	96.7
Sir Adam Beck 1 GS, G6/G8	86372	G6	53.1	5.0	232.3	226.2
		G8	53.1	5.0		
Sir Adam Beck 2 GS, G20/G19	87768	G20	93.7	1.5	377.5	353.0
		G19	93.7	1.5		
Sir Adam Beck 2 GS, G18/G17	87356	G18	93.7	1.5	361.1	344.2
		G17	93.7	1.5		
Total			**718.0**	**22.5**	**1376.8**	**1279.1**

Note 1: Total project cost as per Ex. D1-1-2, Table 1.

Chart 2 – Tier 2 Projects (Allocated)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Total Project Cost[2] ($M)	In-service 2027-2031 ($M)
Otto Holden GS, G1	87545	G1	28.1	1.9	13.3	12.0
Stewartville GS, G5	82351	G5	57.9	0.7	19.1	17.1
Total			**86**	**2.6**	**32.4**	**29.1**

Note 2: Total project cost as per Ex. D1-1-2, Table 2b.

Refer to Ex. L-D1-Staff-064 for further details on the use of unallocated portfolio funding.

Chart 3 – Unallocated Projects (Estimated Investment Cost >$10M)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost[3] ($M)	In-service 2027-2031 ($M)
Otter Rapids GS, G4	82545	G4	45.6	5.1	43.1	35.7
Otter Rapids GS, G3	82544	G3	45.6	5.1	43.3	35.8
Chenaux GS, 1st Unit	87529	G1	18.0	0.0	15.2	13.8
Chenaux GS, 2nd Unit	89134	G2	18.0	0.0	15.3	13.5
Chenaux GS, 3rd Unit	89135	G3	18.0	0.0	15.6	13.6
Otto Holden GS, G2	87546	G2	28.1	1.9	11.5	10.2
Otto Holden GS, G3	89154	G3	28.1	1.9	11.7	10.4
Otto Holden GS, G4	89155	G4	28.1	1.9	11.9	10.6
R.H. Saunders GS, G10	87548	G10	56.5	9.7	35.1	29.0
R.H. Saunders GS, G2	87549	G2	66.2	0.0	35.2	30.2

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

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost[3] ($M)	In-service 2027-2031 ($M)
Stewartville GS, 2nd Unit	87550	G4	57.9	0.7	18.6	17.1
Stewartville GS, 3rd Unit	87551	G1	22.1	0.0	19.0	17.5
Stewartville GS, 4th Unit	89168	G2	22.1	0.0	18.8	17.3
Stewartville GS, 5th Unit	89169	G3	22.1	0.0	19.3	17.6
Chat Falls[4] GS, G2-G9	87525	G3	24.0	0.0	32.5	27.6
		G7	24.0	0.0		
		G4	24.0	0.0		
		G8	24.0	0.0		
		G5	0.0	0.0		
		G6	0.0	0.0		
		G2	0.0	0.0		
		G9	0.0	0.0		
Manitou Falls GS, G1	89245	G1	14.9	0.0	40.5	37.0
Manitou Falls GS, G2	89246	G2	14.9	0.0	40.2	37.0
DeCew Falls 1 GS, G5, G6, G7, G8	89524	G5	5.7	0.0	126.0	126.0
		G6	5.7	0.0		
		G7	5.7	0.0		
		G8	5.7	0.0		
DeCew Falls 2 GS, G2	87963	G2	72.0	0.0	17.6	16.7
Total			**697**	**26.3**	**570.4**	**516.7**

Notes:
3. Estimated investment cost for unallocated projects greater than $10M as per Ex. L-D1-Staff-064, Attachment 1.
4. Total station installed capacity is 192 MW; OPG is entitled to 50% of the capacity (96 MW) – see Ex. A1-4-2, Section 2.1.

Chart 4 – Tier 3 Allocated Projects and Unallocated Projects (Estimated Total Project Cost <$10M)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost ($M)	In-service 2027-2031 ($M)
Hanna Chute GS, G1	87306	G1	1.4	0.0	2.9	2.8
Meyersburg GS, G2	86214	G2	1.7	0.0	9.3	8.5
Meyersburg GS, G3	87704	G3	1.7	0.0	6.7	6.3
Seymour GS, G5	89228	G5	1.1	0.0	0.7	0.6
Seymour GS, G4	89229	G4	1.1	0.0	0.7	0.7
South Falls GS, G1	83204	G1	2.2	0.0	7.9	7.5
South Falls GS, G3	83205	G3	2.2	0.0	8.4	8.0
Hagues Reach GS, G2/G3	86852	G2	1.2	0.0	5.7	5.4
		G3	1.2	0.0		
Total			**12.**	**0.0**	**42.3**	**39.8**

Chart 5 – Summary of Sustaining MW and Added Capacity

	Capacity Sustained MW	Planned Capacity Added MW
Chart 1	718.0	22.5
Chart 2	86.0	2.6
Chart 3	697.0	26.3
Chart 4	13.9	0.0
Total	**1,514.9**	**51.4**

AMPCO Interrogatory #092

Interrogatory

Reference:
F1-1-1 pp.5-6

Question(s):

With respect to the overhaul projects planned over the 2027-2031 period, please complete the following Table:

2027-2031 Hydroelectric Overhaul Projects (OM&A)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	OM&A $ 2027-2031
Total					

Response

Refer to Chart 1 for projects with OM&A forecast spending for the regulated hydroelectric facilities in the 2027 test year only. The overhaul projects listed in Chart 1 are executed concurrently with related capital projects identified in Ex. L-F1-AMPCO-091, which provides a complete list of capital projects comprising the 1500 MW of sustained capacity. Accordingly, Chart 1 represents a subset of the projects that collectively contribute to the 1500 MW of sustained capacity. Overhaul projects do not add capacity.

OPG does not perform Levelized Cost of Energy ("LCOE") analyses for overhaul projects.

Chart 1 – 2027 Regulated Hydroelectric Overhaul Projects

2027 Regulated Hydroelectric Overhaul Projects (OM&A)		Project #	Capacity Sustained (MW)	2027 OM&A ($M)
Station	**Unit**			
Otter Rapids GS	G1	82515	45.6	0.0
Otter Rapids GS	G4	82528	45.6	5.8
Chenaux GS	G1	87555	18.0	1.0
Otto Holden GS	G1	87558	28.1	1.8
Otto Holden GS	G2	87559	28.1	4.2
R.H. Saunders GS	G16	86945	61.7	3.1
R.H. Saunders GS	G2	87562	66.2	1.1
R.H. Saunders GS	G10	87565	56.5	3.7
Stewartville GS	G5	82340	57.9	5.8
Stewartville GS	G4	87566	57.9	3.9
Stewartville GS	G1	89183	22.1	0.5
Alexander GS	G2	82523	12.6	0.7
Manitou GS	G3	86859	14.9	0.6
Meyersburg GS	G2	86230	1.7	0.4
Meyersburg GS	G3	87705	1.7	0.1
DeCew Falls 1 GS	G5	89517	5.7	3.5
	G6		5.7	
	G7		5.7	
	G8		5.7	
Sir Adam Beck 1 GS	G4	82416	53.1	0.1
Sir Adam Beck 1 GS	G6	86373	53.1	1.1
	G8		53.1	
Sir Adam Beck 2 GS	G20	84293	93.7	1.3
	G19		93.7	
Sir Adam Beck 2 GS	G18	89422	93.7	1.1
	G17		93.7	
Total			**1075.5**	**39.8**

OPG declines to provide the requested information for the outer years of the period (i.e., 2028-2031) as this information is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor which relies on a five-year forecast of capital related revenue requirement,

OPG's proposed hydroelectric rate-setting methodology is based on a cost of service review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

AMPCO Interrogatory #093

Interrogatory

Reference:
F1-1-1 p.8

Question(s):

With respect to the redevelopment projects planned over the 2027-2031 period, please complete the following Table:

2027-2031 Hydroelectric Redevelopment Projects (capital)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	Total Project Cost ($M)	In-service $ 2027-2031
Total						

Response

Refer to Chart 1 for the requested information.

Chart 1 – Redevelopment Projects (Allocated)

2027-2031 Hydroelectric Redevelopment Projects (capital)	Proj. #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated LCOE ($/MWh)	Total Proj. Cost[2] ($M)	In-Service[2] 2027-2031 ($M)
Bingham Chute GS Redevelopment[1]	86385	1.0	1.0	~83 ($2026)	24.0	0.5
Kakabeka Falls GS Redevelopment	86386	24.6	2.8	~90 ($2024)	519.0	487.1
Matabitchuan GS Redevelopment	86387	9.6	2.4	~125 ($2024)	190.0	183.4
Coniston/Stinson GS Redevelopment	82087	8.1	3.9	~110 ($2024)	178.0	45.9
Total		**43.3**	**10.1**		**911.0**	**716.9**

Notes:

[1] Project #86385 Bingham Chute GS Redevelopment has not yet progressed to the Execution Phase; levelized cost of energy ("LCOE"), total project cost, and in-service dates are based on a Class 4 estimate. A Class 3 estimate and refined estimate of added capacity will be completed for the project's transition into the Execution Phase.

[2] Total project cost and in-service amounts for Kakabeka Falls GS, Matabitchuan GS and Coniston/Stinson GS Redevelopment Projects are provided in Ex. D1-1-2, Table 1. Total project cost and in-service amounts for Bingham Chute GS Redevelopment are provided in Ex. D1-1-2, Table 2b.

AMPCO Interrogatory #094

Interrogatory

Reference:
F1-1-1 p.15

Question(s):

With respect to the expansion opportunities planned over the 2027-2031 period, please complete the following Table:

2027-2031 Expansion Projects (capital)	Project #	# New Units	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	Total Project Cost ($M)	In-service $ 2027-2031
Total							

Response

Refer to Chart 1.

OPG is exploring adding generation to Chats Falls GS, an existing hydroelectric station, in the form of a new generating unit, in line with the Province's 2025 Integrated Energy Plan[1] and the 2023 Powering Ontario's Growth Report[2]. The project is a proposed investment (i.e., unallocated – refer to Ex. L-D1-Staff-064) and has not yet progressed to the Development Phase. The estimated investment cost is considered preliminary and will be refined if the investment transitions into the Development Phase (in accordance with the processes described in Ex. D2-1-1, p. 7). An estimated Levelized Cost of Energy will be determined once the project reaches such Gate 1, and the investment cost estimate and planning have further matured.

[1] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p. 54
[2] Province of Ontario, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, p. 53

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

Chart 1 – Regulated Hydroelectric Proposed Expansion Investments

2027-2031 Expansion Projects (capital)	Project #	# New Units	Capacity Sustained (MW)	Planned MW Capacity Added (MW)[1]	LCOE $/MWh	Estimated Investment Cost ($M)[1]	In-service $ 2027-2031
Chats Falls GS Expansion	89553	1	0	16.5	n/a	124	0
Total	**-**	**1**	**0**	**16.5**	**-**	**124**	**0**

Note 1: As this facility is jointly owned with Hydro-Québec, 16.5 MW represents one-half of the capacity of the proposed new unit. Hydro-Québec is entitled to one-half of the energy, and the investment cost will be shared. The figure of $124M represents OPG's portion of the estimated investment cost.

AMPCO Interrogatory #095

Interrogatory

Reference:
F1-1-1 pp.17-29

Question(s):

For each of the measures under the Performance Metrics of Safety, Environment, Reliability, and Cost Effectiveness, please provide 2025 Actuals.

Response

Refer to Ex. L-F1-SEC-153.

AMPCO Interrogatory #096

Interrogatory

Reference:
F1-1-1 p.23

Question(s):

a) With respect to planned outages over the 2016-2024 period, please provide the forecast percentage allocated to the Eastern Region, Niagara Region and Western Region.

b) With respect to planned outages over the 2025-2031 period, please provide the forecast percentage allocated to the Eastern Region, Niagara Region and Western Region.

Response

a) Refer to Ex. F1-1-1, p. 23 for a breakdown of the 2016-2024 actual planned outages for the regulated hydroelectric facilities by region. OPG notes that there are no OEB-approved amounts for the years in questions, and declines to provide any internal forecasts on the basis that this request goes beyond the scope of the OEB's current Filing Requirements, which were subject to extensive consultation in EB-2024-0136 with the "aim to address evolving regulatory landscape and *incorporate lessons learned from past proceedings.*"[1] (emphasis added)

b) Percentage allocation of planned outages for the regulated hydroelectric facilities by region for 2025 (actuals) and 2026-2027 (forecast) are presented in Chart 1. OPG declines to provide 2028-2031 forecast outage data for the same reasons as outlined in Ex. L-A1-SEC-011, part (a).

[1] EB-2024-0136, OEB Letter re Updated Filing Requirements for Ontario Power Generation Inc. (September 17, 2024), p. 1.

Chart 1 – 2025 (Actuals) and 2026-2027 (Forecast) Planned Outage Allocation by Region

Region	2025 (Actuals)	2026-2027 (Forecast)
Eastern Region	71%	60%
Niagara Region	18%	29%
Western Region	11%	11%
Total	**100%**	**100%**

AMPCO Interrogatory #097

Interrogatory

Reference:
F1-1-1 p.28

Question(s):

With respect to Chart 10 and Chart 11, please provide the data that underpins the Regulated Hydroelectric Unit Energy Cost Forecast ($/MWh) calculation for each of the years 2016 to 2027 including 2025 actuals and in the response provide 2014 and 2015 actuals.

Response

Refer to Attachment 1.

For clarity, annual submissions to the OEB for Regulated Hydroelectric Unit Energy Cost are completed at a point in time and are not restated to reflect any subsequent organizational changes.

As per the OEB's Decision and Order, EB-2016-0152, December 28, 2017, p. 149, there was no requirement to file targets prior to 2017.

Numbers may not add due to rounding.

Ex. L-F1-AMPCO-097 - Attachment 1
Regulated Hydroelectric Unit Energy Cost Forecast & Actual ($/MWh, 2025-2027)
Unit Energy Cost Target and Actual - 2014-2027[6]

UEC Calculation	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Target	2017 Actual	2018 Target	2018 Actual	2019 Target	2019 Actual	2020 Target	2020 Actual	2021 Target	2021 Actual
Base OM&A	171.0	192.9	194.1	205.1	200.7	176.6	201.2	189.2	199.1	198.8	198.3	190.4	200.2
Project OM&A[1]	45.1	52.4	39.0	61.0	42.3	70.8	53.6	52.9	53.8	65.7	51.9	84.1	81.0
Asset Service Fee[1]	5.6	6.3	5.2	5.3	5.7	5.9	5.6	6.1	6.9	9.4	7.9	9.2	9.9
Total Direct OM&A	221.7	251.6	238.3	271.4	248.7	253.2	260.4	248.2	259.8	273.9	258.1	283.7	291.0
Generation - net of SBG spill (TWh)[3,5]	31.4	30.4	29.5	31.2	30.7	30.5	29.8	29.6	30.5	31.3	30.3	32.2	29.0
Actual as submitted in F1-1-1 ($/MWh)[4]	7.1	8.3	8.1	N/A	8.1	N/A	8.7	N/A	8.5	N/A	8.5	N/A	10.0
Target as submitted in RRR ($/MWh)	N/A	N/A	N/A	8.7	N/A	8.3	N/A	8.4	N/A	8.8	N/A	8.8	N/A

UEC Calculation	2022 Target	2022 Actual	2023 Target	2023 Actual	2024 Target	2024 Actual	2025 Target	2025 Actual	2026 Target	2027 Target
Base OM&A	204.3	216.4	215.6	231.7	239.1	248.4	261.1	256.0	274.2	286.2
Project OM&A[1]	82.8	69.9	70.7	73.0	93.6	59.7	89.6	62.5	83.9	119.6
Asset Service Fee[1]	11.5	13.5	11.0	14.8	15.1	15.5	15.7	18.0	20.7	24.2
Direct OM&A ($M)	298.7	299.8	297.3	319.5	347.8	323.6	366.4	336.5	378.7	430.0
Generation - net of SBG spill (TWh)[3,5]	32.6	31.1	31.8	31.4	31.7	32.5	33.0	30.9	32.8	32.5
Actual as submitted in F1-1-1 ($/MWh)[4]	N/A	9.6	N/A	10.2	N/A	10.0	N/A	10.9	N/A	N/A
Target as submitted in RRR ($/MWh)[4]	9.2	N/A	9.3	N/A	11.0	N/A	11.1	N/A	11.5	13.2

Notes

1 Hydro redevelopment costs excluded, operating components of asset service fees excluded
2 No targets were submitted in RRR until 2017
3 2025-2027 production values are on a pre-spill basis, i.e. there are no deductions made for SBG as per Ex. E1-1-1, Section 3.1
4 RRR targets filed are subject to change upon finalization of assumptions and cost allocations
5 Actual generation is net of SBG spill
6 UEC is calculated at a point in time and not subsequently restated for organizational changes

AMPCO Interrogatory #098

Interrogatory

Reference:
F1-1-1 p.29

Question(s):

a) With respect to Chart 12, please provide the data that underpins the Regulated Hydroelectric Total Generation Cost Performance ($/MWh) calculation for each of the years 2016-2024 and in the response include 2014 and 2015 actuals.

b) With respect to Chart 12, please provide the calculation of the forecast Regulated Hydroelectric Total Generation Cost Performance ($/MWh) for each of the years 2025 to 2027 including 2025 actuals.

c) Please confirm why redevelopment projects are excluded from TGC calculation.

Response

a) Refer to Attachment 1 for 2014-2024 data that underpins the Regulated Hydroelectric Total Generation Cost Performance ("TGC") in Ex. F1-1-1, Chart 12, including 2014 and 2015 actuals.

In the course of responding to this interrogatory, OPG identified a minor discrepancy in the reconciliation of the 2024 TGC. The revision has been reflected in Attachment 1. The impact of the correction reduced the 2024 three-year average to $31.8/MWh from $32.0/MWh reported in the 2024 RRR submission.

b) Refer to Attachment 1 for 2025 actuals data that underpins the regulated hydroelectric TGC performance. As discussed in Ex. L-F1-Staff-168, OPG does not set Total Generating Cost targets for the regulated hydroelectric business.

c) Refer to Ex. L-F1-SEC-153.

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Numbers may not add due to rounding.

Ex. L-F1-AMPCO-098 - Attachment 1
Regulated Hydroelectric Total Generating Cost Actuals ($/MWh)

		Actual 2014 [1]	Actual 2015 [1]	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	
1	**Total Regulated Hydroelectric Generation - pre spill (MW)**	**34.7**	**33.3**	**33.7**	**35.9**	**33.0**	**33.8**	**34.6**	**30.9**	**32.7**	**32.4**	**32.9**	**31.6**	
2	Total OM&A for Value for Money Metrics ($M)	295.2	318.1	301.9	305.0	309.7	309.1	308.1	347.8	348.5	374.5	387.8	394.5	
3	Total Capital for Value for Money Metrics ($M)	80.0	83.3	125.5	118.4	131.8	170.9	220.6	285.7	229.1	342.4	379.2	497.7	
4	Total Fuel for Value for Money Metrics ($M)	352.6	353.3	362.0	388.5	360.7	366.6	379.6	341.9	352.3	350.4	355.6	343.0	
5	**Total Generating Costs for Value for Money Metrics ($M)**	**727.9**	**754.6**	**789.4**	**811.9**	**802.1**	**846.7**	**908.3**	**975.4**	**930.0**	**1067.3**	**1122.6**	**1235.2**	**Line 2 + Line 3 + Line 4**
6	Total Generating Costs per MWh ($/MWh) - 1 Year	21.0	22.7	23.4	22.6	24.3	25.0	26.3	31.6	28.5	32.9	34.1	39.0	**Line 5 divided by Line 1**
7	**Total Generating Costs per MWh ($/MWh) - 3 Year**	**N/A**	**N/A**	**22.4**	**22.9**	**23.4**	**24.0**	**25.2**	**27.6**	**28.8**	**31.0**	**31.9**	**35.4**	**Average of rolling 3 years**

Notes

1 2014 and 2015 data per RRR filing
2 RRR filings are subject to change upon finalization of assumptions and cost allocations
3 Numbers may differ slightly from pre-filed RRRs due to rounding.

AMPCO Interrogatory #099

Interrogatory

Reference:
F1-1-1 Table 1

Question(s):

Please add 2014 and 2015 OEB-approved and Actuals to Table 1 split between Previously Regulated Hydroelectric and Newly Regulated Hydroelectric.

Response

Consistent with the OEB's Letter regarding OPG's Updated Filing Requirements in EB-2024-0136 dated September 17, 2024, OPG has determined that it is unable to meaningfully provide the 2014 and 2015 information requested by this interrogatory. Organizational and cost structure changes over the past decade have made it impossible to present the 2014 and 2015 historical actual OM&A costs, compensation and benefits details, and staffing information for the regulated hydroelectric business in a manner that is comparable to the data provided in Ex. F1-1-1, Table 1.

AMPCO Interrogatory #100

Interrogatory

Reference:
F1-1-1 Table 2b

Question(s):

Please split Regulated Hydroelectric OM&A FTEs (Regular, Non-Regular, Temporary) between Base OM&A and Project OM&A.

Response

Refer to Attachment 1, filed in Microsoft Excel format.

AMPCO Interrogatory #101

Interrogatory

Reference:
F1-3-3 Table 1

Question(s):

With respect to Project #82328 Otto Holden GS Concrete Mitigation Phase 2, please provide the following:

a) Project Close Out Report.

b) Post Implementation Review (PIR) Report.

c) CPI and SPI results.

Response

a) Refer to Attachment 1.

b) Refer to part a). Consistent with OPG's governance, for Project #82328, the Project Closure Report is used as the PIR report.

c) The CPI for this project is 0.95; the SPI is 1.0.

ONTARIO POWER GENERATION

OPG Confidential
FIN-FORM-PA-004-R03
Project Closure Report

Part 1: Project Account Closure - Complete for all projects			
Is this PCR also used as a PIR report?	Yes	**Records Document Number (required only when the PCR is also used as a PIR report)**	NA6-REP-08700-1631650
Organization	RG - Renewable Projects	**Date**	04/10/2025
Project Number	82328	**Site / Location Name**	OTO - OTTO HOLDEN
Project Title	82328 OTO - CONCRETE MITIGATION PHASE 2		
Project and Asset (if any) Description	82328: Scope includes restoring the deteriorated concrete structure to its original functionality. Items to be completed east gravity dam restoration, tailrace training wall repairs, downstream powerhouse wall restoration, tailrace deck grating replacement, west gravity dam crack injection, powerhouse beam restoration, headworks deck restoration (U6-U8), headworks beam restoration (U7/U8), Pier #1 restoration.		
Super Asset Number	N/A	**Asset Class**	N/A
Company Code	N/A	**Business Area**	N/A

Part 2: Final In-service Transfer - Complete for CAPITAL projects	
Final In-service Transfer Credit Amount (Controller)	

Part 3: Project Cost and Schedule Variance - Complete for all projects

When the Cost variance is not within the acceptable range as per OPG Estimate Manual, OPG-MAN-00120-0012, cost variance root cause should be captured (e.g., inflation, scope, performance issues, etc.).

	(1) Original Approved Estimate	**(2) Current Approved Estimate**	**(3) Final / Actuals**	**(4) Variance (=3-2)**
Cost	23,600,000.00	31,820,000.00	30,995,895.78	(824,104.22)
Schedule (In-serivce date)	12/01/2020	03/31/2022	11/15/2022	32 weeks behind of schedule

Deliverables (Completed? Intended Functionality Achieved? Target vs. Actions?)

DELIVERABLES:
The following have been completed and restored:
- Restoration of the East and West gravity dams and the downstream powerhouse wall.
- Replacement of the tailrace deck grating.
- Completion of powerhouse beams.
- Restoring of the powerhouse floor to its original load-bearing capacity.
- Completion of the U7/U8 deck and beams, downstream training wall, and U6 deck.
- Completion of the U3/U4 in-water beams and the U1 to U6 downstream deck.
- Completion of the U4/U5 deck, U5/U6 in-water beams, and U7/U8 downstream deck.
- Completion of the U2/U3 deck, U1/U2 in-water beams, U1 pier, and U1 deck.

COST VARIANCE:

PREVIOUS BCS - According to the previous BCS estimate of $23,600,000 the project initially exceeded the budget by $8,220,000. This was due to unforeseen and as-found Alkali Aggregate Reaction (AAR) concrete conditions that were not apparent until removal, as well as changes in environmental regulation requirements.
Reference the previous BCS attached to this PCR, NA6-PLAN-26100-0002.

SUPERSEDING BCS - Based on the superseding BCS estimate of $31,820,000, the project was actually under budget by $824,104.22 due to a lower drawdown of contingency funds. Below is a summary of the variances between the previous BCS and the superseding BCS estimates:

OPG Project Management: To support schedule extension and unforeseen and as-found concrete conditions.
Previous BCS = $485,000
Superseding BCS = $729,000
Variance = $244,000

OPG Engineering including Design: To provide additional engineering and design support for schedule extension.
Previous BCS = $188,000
Superseding BCS = $233,000
Variance = $45,000

OPG Procured Materials: To procure additional miscellaneous materials and DFO/MNR testing not originally contemplated.
Previous BCS = $0
Superseding BCS = $141,000
Variance = $141,000

OPG Other (PWU): Underestimated production support requirements included unanticipated log operations and switching for diver safety and water management.
Previous BCS = $438,000
Superseding BCS = $1,026,000
Variance = $588,000

Construction Contract(s): To support schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $19,950,000
Superseding BCS = $26,397,000
Variance = $6,447,000

Consultants: To support schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $409,000
Superseding BCS = $814,000
Variance = $405,000

Contingency: To cover schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $2,130,000
Superseding BCS = $2,480,000
Variance = $350,000

TOTAL:
Previous BCS = $23,600,000
Superseding BCS = $31,820,000
Variance = $8,220,000

Reference the superseding BCS attached to this PCR, NA6-BCS-08707-0007 R0, Appendix B, Project Variance Analysis, for a summary of the variances between the original BCS and the superseding BCS.

SCHEDULE VARIANCE:
A schedule variance of 32 weeks has arisen due to unexpected and as-found concrete conditions that became apparent only after concrete removal due to AAR, along with changes in environmental regulation requirements.

Associated REIS									
ID	**Project Number**	**Status**	**Approved Project Amount**	**Project Release Date**	**In Service Amount Prev Reported**	**Capital In Service Amount**	**Date Placed In Service**	**Date Ready For Service**	**LTD Actual Expenditure**

Lessons Learned				
Lessons Learned ID	**Title**	**Description**	**Category**	**Recommendation**

History of BCS						
Document Number	**Gate**	**Sub Gate**	**Release**	**Approval Date**	**Target Completion Date**	**Total Cost Estimate**

Finance SPOC Reviewer	
Reviewer	(202025) Rob Pretty
	Senior Financial Analyst Eastern Region Operations Controllership
Signature	Approved by: Rob Pretty
Date	4/25/2025 10:01:33 AM

Part 4: PCR Approval Signature - Complete for all projects			
Project Manager: The project is declared closed. I confirm that all remaining materials (if applicable) of the project are appropriately dispositioned as spare parts to accepting business areas or are declared surplus. No cost shall be charged to this project at this point forward.		**Controller for Project Organization (if applicable, i.e., the BU/Function has a Project Organization Controller):** I confirm the information documented in this PCR is correct.	
Project Manager	(202014) Jeff Hautanen	**Controller for Project Organization**	
	Senior Manager Projects Ottawa Projects Projects		
Signature	Approved by: Jeff Hautanen	**Signature**	
Date	4/25/2025 4:19:58 PM	**Date**	
Station/Plant Group/Function Controller: I confirm the information documented in this PCR is correct.		**Asset Owner:** I authorize the decision to declare project closure for this project.	
Controller for Sponsoring Organization	(212399) Martin Rupnik	**Asset Owner or Sponsoring Organization Authority**	(204230) Scott Gagnon
	Finance Controller Eastern Region Operations Controllership		Director Plant Operations Southeast Operations S: Production

Signature	Approved by: Martin Rupnik	**Signature**	Approved by: Scott Gagnon
Date	5/5/2025 1:24:30 PM	**Date**	5/8/2025 1:01:31 PM

Part 5: PIR Signature - Required only when the PCR is also used as a PIR report	
I have reviewed and accept the PIR results in this report.	
Project Sponser	(209693) Amanda Griener
	Director Asset & Project Mgmt Production Support Production Support
Signature	Approved by: Amanda Griener
Date	5/14/2025 1:35:50 PM

Part 6: Distribution - Required only when the PCR is also used as a PIR report	
Distribution: When this PCR is also used as a PIR report, the Project Sponsor shall ensure distribution (cc) to the following personnel if they have not already signed off above:	
Name **Title, Department, BU/Function**	
Finance Approver	
Line Approver	

Other Key Stakeholders

Part 7: PCR Checklist - Compele for all projects CSA or Project Manager		
Checklist Item	**Complete**	**Explanation**
Indicate if PCR related to a Project where Default Labour was posted via MyTime	Yes	Work events closed in EBX
Request sent to AS9 buyer to close PO/COs after closing related MRs/CRs	Yes	On 17-Apr/25, an email was sent to Katie P. to close 1 open MR; and another email was sent to Richard Marzec to close 1 open CN.
Request sent to Planner to close any AS9 Work Order Tasks	N/A	There is no open WOT.
Request sent to ONCORE to close all tasks and associated PO's	N/A	
All accruals have been cleared.	Yes	
Any purchases through purchasing cards (VISA) or Ariba Web Catalogue have been reconciled in Concur or shipped by Ariba Vendor	Yes	

All default Business Expense or VISA default accounts have been changed.	Yes	
All spare parts have been set up in AS9, including: Inventory by Cat ID with ROP/TMAX values	N/A	
Capital Spares are set up in the appropriate Asset Class and account	N/A	
All obsolete or surplus inventory or components have been identified and Surplus Declaratations routed to ensure that all retired assets have been properly removed from the fixed asset ledger and inventory accounts.	N/A	
The Super Asset Class, the Company Code, Super Asset Numbers agree with previous REIS.	N/A	
The Final Actual Costs and Current Approved Estimate agree with FRA and/or SAP.	Yes	
If this is combined PCR/PIR, it was defined in the approved BCS.	Yes	
If the Actuals are greater than the Approved amount, the overspend has been approved in accordance with the appropriate OAR Element specified in the BCS standard (OPG-STD-0076, Developing and Documenting Business Cases), with an approved OPG-FORM-0077, Project Over-Variance Approval or a Superseding BCS.	Yes	There is an approved superseding BCS for the overspend (NA6-BCS-08707-0007 R0).
A copy of the FRA and/or SAP Report is attached.	Yes	SAP is not applicable

Project CSA / Project Manager (Sign-Off): I confirm the completion of all the checklist items.	
Project CSA or Project Manager	(222289) Charles Shariff
	Project Control Officer SEO Projects RG & Corp
Signature	Confirmed by: Charles Shariff
Date	4/25/2025 9:32:33 AM

AMPCO Interrogatory #102

Interrogatory

Reference:
F1-3-3 Table 2

Question(s):

a) Please add the following column to Table 2:
   i. Total Project Cost at time of EB-2020-0290
   ii. Final Completion Date at time of EB-2020-0290.

b) Please confirm all OM&A projects with 2025 to March 2026 completion dates were completed as planned.

Response

a) OPG declines to provide the requested information on the basis of lack of clarity and relevance. Hydroelectric OM&A projects were not within scope in EB-2020-0290 and did not form the basis for setting payment amounts for the current 2022-2026 IR term. In addition, OPG notes that all but five projects in Ex. F1-3-3, Table 2 are identified as completed before 2027, and therefore do not form part of the 2027 test year revenue requirement that is within the scope of this proceeding.

b) Refer to Attachment 1. Note that for OM&A projects, Final Completion Date refers to the date at which the project is closed, which is subsequent to the date on which the work is substantially completed.

Ex. L-F1-AMPCO-102 - Attachment 1
Status of OM&A Projects With Completion Dates Jan 2025 - March 2026

Project Name	Project Number	EB-2025-0297 Final Completion Date	Actual / Forecast Completion Date	Completion Status	Variance Explanation
OTO - G7 Overhaul - Mechanical/Electrical Unit Overhauls	82326	Jan-25	Jan-25	Completed as planned	
R.H. Saunders GS - Concrete Growth Mitigation	80788	Feb-26	Mar-26	Late completion	No material difference.
Des Joachims GS - Headworks Piers Concrete Repairs	82588	Sep-25	Sep-25	Completed as planned	
BAR - NS G4 Mech/Elec Overhaul	84588	Feb-25	Feb-25	Completed as planned	
BAR - G1 Mech/Elec Overhaul	86078	Feb-26	Apr-26	Late completion	Project closed, delay to project closeout report completion.
BAR G2 Mech/Electrical Overhaul	86079	Dec-25	Apr-26	Late completion	Project closed, delay to project closeout report completion.
OTO - G8 Overhaul (NS)	86476	Jan-26	Aug-26	Pending	Project work complete. Administrative closeout in progress.
OTO - G5 Overhaul; NS	86481	Sep-25	Feb-26	Late completion	Project closed, delay to project closeout report completion.
SAU - Concrete Growth Mitigation	80788	Feb-26	Mar-26	Late completion	No material difference.
SAU - Unit Hatchcover Refurb	82334	Jun-25	Jun-25	Completed as planned	
DEJ - Auxiliary Dam Repair Deck & Handrails	84161	Dec-25	Jul-26	Pending	Project work complete. Administrative closeout in progress.
Otter G2 Non-Standard Overhaul	82521	Mar-26	May-26	Pending	Refer to Ex. L-D1-Staff-316.
Dredge Tunnel 1 and 2 Intakes	82413	Mar-25	Mar-25	Completed as planned	
Whitesand Erosion Repairs	80749	Dec-25	Dec-26	Pending	Work is substantially complete, ongoing monitoring in progress to ensure shoreline stability.

CCC Interrogatory #066

Interrogatory

Reference:
Exhibit F1, Tab 2, Schedule 1, pp. 3-4

Preamble:

2023 Actual versus 2022 Actual

Actual Base OM&A costs in 2023 were $236.5M, which was $21.0M or 10% higher than 2022 actual amount of $215.5M. All regulated hydroelectric organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including as a result of Bill 124, as discussed in Ex. F4-3-1.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation, with additional drivers of variance identified below where applicable:

- Operations and Maintenance ($17.0M or 12% increase):

- Operations ($2.5M or 10% increase): no other reportable variance

- Maintenance ($14.4M or 12% increase): due to higher maintenance costs primarily at R.H. Saunders GS and Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (see Ex. A1-4-2).

- Integrated Fleet Management ($3.7M or 82% increase): due to increased staffing levels in security, and training to support increased work program and address training backlogs.

- Enterprise Projects ($1.0M or 51% increase): due to higher staffing levels to support the increased regulated hydroelectric project portfolio.

Question(s):

When were the environmental remediation, storm response clean-up, and additional joint works expenditures completed?

Response

OPG interprets this interrogatory to be referencing Ex. F1-2-2, pp. 3-4.

Environmental remediation, storm response clean-up, and joint works expenditures cited were completed in 2023.

CCC Interrogatory #067

Interrogatory

Reference:
Exhibit F1, Tab 2, Schedule 1, pp. 3-4

Preamble:

The OM&A projects within the regulated hydroelectric portfolio are largely sustaining expenditures for repairs and maintenance, including turbine-generator overhaul projects and projects related to aging civil infrastructure. OPG defines a project (whether capital or OM&A) as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program.

Question(s):

a) Please provide the forecast hydroelectric Project OM&A budgets from 2028 to 2031.

b) How much, if any, of the proposed 2027 Project OM&A is eligible for the CRVA?

Response

a) OPG declines to provide the requested information for the outer years of the period (i.e., 2028-2031) as this information is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

b) The proposed 2027 Project OM&A costs include $25.3M of non-capital costs related to CRVA-eligible projects, as noted in Ex. F1-3-1, Table 1, Note 4.

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

CCC Interrogatory #068

Interrogatory

Reference:
Exhibit F1, Tab 4, Schedule 2, p. 1

Preamble:

The GRC is directly dependant on energy production and year-over-year GRC variances result from production impacts (primarily unit outages, water conditions, and market conditions, see Ex. E1-1-1 and Ex. E1-1-2). For historical periods, GRC is based on the actual energy production. GRC forecasts are calculated based on the energy production forecast described in Ex. E-1-1-1. The differences between actual and forecast production that are attributable to changes in natural water conditions will be captured in the Hydroelectric Water Conditions Variance Account. The account applies to 27 regulated hydroelectric plants, located on nine river systems (see Ex. E1-1-1, Appendix 1 and Ex. H1-1-1). Changes in GRC associated with these energy variances are included in determining the account balance (see Ex. H1-1-1).

Question(s):

Please confirm that differences in GRC caused by differences in unit outages and market conditions are not captured in any variance account, and OPG is not proposing to capture such impacts in a new or existing variance account.

Response

Not confirmed. Differences between actual and forecast production can be attributable to market conditions that give rise to surplus baseload generation ("SBG"), the impact of which is recorded in the Hydroelectric Surplus Baseload Generation Variance Account. As discussed in Ex. H1-1-1, Section 5.4, the account captures such impacts net of associated GRC variances. These effects are fully captured in the account as OPG's hydroelectric payment amounts have been set using a hydroelectric production and GRC cost forecast that is not reduced by SBG. OPG proposes to continue with this approach in this Application, with SBG further discussed in Ex. E1-2-1, Section 4.0.

OPG confirms that differences in GRC costs attributable to unit outages or non-SBG market conditions are not captured in any variance account.

CCC Interrogatory #069

Interrogatory

Reference:
Exhibit F1, Tab 5, Schedule 1, p. 1, Chart 1

Preamble:

Total OM&A purchased services expenditures for all contactors for the historical period (2016-2024) was $57.1M in 2016, $53.2M in 2017, $57.1M in 2018, $56.5M in 2019, 49.9M in 2020, $64.7M in 2021, $78.3M in 2022, $80.2M in 2023, and $71.4M in 2024. For OM&A purchased services where costs are allocated to both the regulated and non-regulated facilities within Renewable Generation (such as work centers), only the amounts allocated to regulated hydroelectric facilities have been included (details on OPG's cost allocation methodology are described in Ex. F3-1-4 and Ex. F1-2-1). The average annual OM&A purchased services for the regulated hydroelectric facilities for all contractors over the period of 2016-2024 was $63.1M.

Question(s):

a) What are the budgeted OM&A purchased services expenditures for 2025, 2026 and 2027?

b) How can the contracts in chart 1 be sole sourced because they were less then $500,000, when the chart is supposed to be contracts in excess of $20M?

c) What was the average number of separate contracts/providers per year?

Response

a) Budgeted regulated hydroelectric OM&A purchased services expenditures for 2025, 2026 and 2027 are $93.6M, $95.6M and $120.7M, respectively.

b) As referenced in Ex. F1-5-1, p. 1, lines 26-28, the information presented in Chart 1 is contracts for OM&A purchased services with spend equal to or in excess of the $20M threshold, per supplier, for the years between 2016-2024. Since the information is presented as an aggregate for each supplier, an individual contract could be included in the aggregate that was issued by the supplier that is under the single-source threshold of $500,000.

c) OPG interprets this question as being the average number of distinct providers with spend, per year, between 2016-2024. The average number of separate providers per year was 305.

CCMBC Interrogatory #001

Interrogatory

Reference:
F1-1-1, Table 1, Operating Costs Summary - Regulated Hydroelectric

Question(s):

a) Please explain the reason for the large increase in Project OM&A from $90.5 million in 2026 Budget to $127.0 million in the 2027 Plan.

b) Why did the Allocation of Corporate Costs decrease from $50.1 million in 2016 to $38.4 million in 2020 and then increase each year to $55.3 million in 2027?

Response

a) The main driver of the increase in regulated hydroelectric Project OM&A costs between 2026 and 2027 is portfolio projects (Ex. F1-3-2, Section 2.1) and infrastructure projects for planned removal costs corresponding with increased refurbishment activity at regulated hydroelectric stations (Ex. F1-3-2, Section 2.2).

b) OPG notes that Allocation of Corporate Costs was $51.0M, not $50.1M, in 2016, per Ex. F1-1-1, Table 1, line 3, col. (a).

The decrease in costs from 2016-2020 was primarily due to a change in allocation methodology to use IT end users as the cost driver for Corporate & Technology Services ("CTS"), as identified in Ex. F3-1-2, p. 5. This methodology change was further discussed in EB-2020-0290, Ex. F3-1-4, Attachment 1, Section 4.1.4, where it was supported and found to be appropriately reflective of the principle of causality by Elenchus Research Associates Inc. in their review of OPG's cost allocation methodology.

As discussed throughout Ex. F3-1-2, pp. 2-5, the increase in the allocation of Corporate Support costs from 2020 to 2027 is largely related to:

- CTS: higher staffing levels to support increased IT requirements from the business and increased cost of digital tools across the enterprise resulting in higher software and hardware costs.
- Finance: higher portion of costs allocated to the regulated hydroelectric business as a result of their higher relative capital expenditures which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).

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

CCMBC Interrogatory #002

Interrogatory

Reference:
F1-1-1, Table 2b, Regulated Hydroelectric Staff Summary – Regular and Non-Regular (FTEs)1 – 2020-2031, and A1-3-2, page 11

Question(s):

a) Considering that OPG has not built or acquired any new hydroelectric stations, please explain the reasons for the increase of 430.1 FTEs or 39,4% in Regulated Hydroelectric Staff from 1091.4 FTEs in 2020 to 1521.5 FTEs in the 2027 Plan.

b) Please confirm that the increase in FTEs is one of the main reasons for the negative productivity of Regulated Hydroelectric of -0.40% and -1.01%.

Response

a) As shown in Ex. F1-1-1, Table 2b, the breakdown of the increase of 430.1 FTEs from 2020-2027 is as follows:

- Regulated Hydroelectric Capital, Regular: 188.6 FTEs
- Regulated Hydroelectric Capital, Temporary: 66.8 FTEs
- Regulated Hydroelectric OM&A, Regular: 173.3 FTEs
- Regulated Hydroelectric OM&A, Temporary: 1.5 FTEs

The increase in Capital Regular FTEs (188.6) and Temporary FTEs (66.8) reflects the addition of personnel required to support the increasing capital investment over the forecast period to address the condition of aging assets in the regulated hydroelectric fleet, as described in Ex. D1-1-1, Section 2.0. As further described in Ex. F1-1-1, Section 3.2, OPG's key business plan focus areas for the regulated hydroelectric facilities include the significant refurbishment program required to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW. The increase in project resources supports the growth of the capital program and ensures capability to manage the increased complexity and volume of work, support schedule adherence, and compliance with enterprise governance requirements.

The increase in OM&A Regular FTEs (173.3) reflects the addition of personnel across project management, operations, maintenance, engineering, and training functions, as described in Ex. F1-2-1, Section 3.4. These additions support

improved fleet performance through key work programs, including enhanced governance, monitoring, and internal controls, as well as address the recommendations from the Auditor General's 2022 Value for Money audit of OPG's hydroelectric facilities to enhance OPG's maintenance planning and management systems (refer to Ex. F1-1-1, p. 4).

OM&A Temporary FTEs are not a significant contributor to the overall increase.

The response to part b) was prepared by London Economics International LLC:

b) Not confirmed. The FTE data referred to in the question is just for OPG, whereas the industry TFP results referred to in the question are for the industry as a whole, which is composed of 21 peers, including OPG. As noted in response to Ex. L-A1-Staff-279, part (h) above, OPG's regulated fleet accounts for only 15% of the industry capacity considered in the industry TFP study (based on data as of 2023). It is also worth noting that FTE data is not available for US peers; therefore, there are not long-term trends around FTEs available for the industry. To understand the key drivers of the industry TFP trends, please see Section 6 of LEI's TFP report.

SEC Interrogatory #146

Interrogatory

Reference:
F1-1-1, p. 4-5

Question(s):

With respect to refurbishment program/projects:

a) With respect to the turbine-generator refurbishment program, please provide a list of projects that constitute the $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period.

b) Please provide a list of the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, including the total cost.

Response

a) Refer to Charts 1 and 2.

Chart 1- List of Allocated Regulated Hydroelectric Refurbishment Projects with Capital Expenditures 2027-2031

Project#	Generating Station and Unit(s)
83148	Abitibi Canyon GS, G1
87545	Otto Holden GS, G1
86937	R.H. Saunders GS, G16
82351	Stewartville GS, G5
86792	Alexander GS, G2
82391	Alexander GS, G1
86793	Alexander GS, G3
87306	Hanna Chute GS, G1
86860	Manitou Falls GS, G3
83204	South Falls GS, G1
86570	Sir Adam Beck 1 GS, G4
86372	Sir Adam Beck 1 GS, G6/G8

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87768	Sir Adam Beck 2 GS, G20/G19
87356	Sir Adam Beck 2 GS, G18/G17
82542	Otter Rapids GS, G1
83356	Otto Holden GS, Runner Only
83104	R.H. Saunders GS, Runner Only
86587	R.H. Saunders GS, G12
83257	Cameron Falls GS, G7
87357	Sir Adam Beck 2 GS, G14/G13

Chart 2- List of Unallocated Regulated Hydroelectric Refurbishment Projects with Capital Expenditures 2027-2031

Project#	Generating Station and Unit(s)
82545	Otter Rapids GS, G4
82544	Otter Rapids GS, G3
87529	Chenaux GS, G1
89134	Chenaux GS, G2
89135	Chenaux GS, G3
87546	Otto Holden GS, G2
89154	Otto Holden GS, G3
89155	Otto Holden GS, G4
87548	R.H. Saunders GS, G10
87549	R.H. Saunders GS, G2
87550	Stewartville GS, G4
87551	Stewartville GS, G1
89168	Stewartville GS, G2
89169	Stewartville GS, G3
87525	Chat Falls GS, G2-G9
86852	Hagues Reach GS, G2/G3
89245	Manitou Falls GS, G1
89246	Manitou Falls GS, G2
86214	Meyersburg GS, G2
87704	Meyersburg GS, G3
89228	Seymour GS, G5
89229	Seymour GS, G4
83205	South Falls GS, G3
89524	DeCew Falls 1 GS

87963	DeCew Falls 2 GS, G2
83157	Abitibi Canyon GS, G3
83159	Abitibi Canyon GS, G4
83161	Abitibi Canyon GS, G5
87516	Arnprior GS, Runners
89112	Arnprior GS, Refurb 1st Unit
89136	Chenaux GS, 4th Unit
89622	Des Joachims GS, G2, G4, G6, G7, G8
87574	R.H. Saunders GS, Field Poles Only
89164	R.H. Saunders GS, 6th Unit
89165	R.H. Saunders GS, 7th Unit
90200	Big Eddy GS, G1
90201	Big Eddy GS, G2
87233	Manitou Falls GS, G4
89247	Manitou Falls GS, G5
89227	Meyersburg GS, G1
80847	Pine Portage GS, G1
84469	Pine Portage GS, G2
87966	DeCew Falls 2 GS, G1
87956	Sir Adam Beck 2 GS, G26/G25
87955	Sir Adam Beck 2 GS, G16/G15
89876	Sir Adam Beck Pump GS 1st unit

b) Refer to Ex. L-F1-AMPCO-091.

SEC Interrogatory #147

Interrogatory

Reference:
F1-1-1, p. 6

Question(s):

Please provide further details on the Renewable Generation Programmatic Collaboration Agreement ("RG PCA"), including but not limited to commitments that OPG has made to the Original Equipment Manufacturers ("OEM") in terms of amount of work, any premiums or penalties, etc.

Response

Refer to Ex. L-D1-Staff-065.

SEC Interrogatory #148

Interrogatory

Reference:
F1-1-1, p. 6

Question(s):

For each of the RG PCA Agreements:

a) Please describe the process that was used to arrive at the agreement.

b) Please provide copies of the agreements.

Response

a) Beginning in 2022, OPG identified that increased demand on hydroelectric original equipment manufacturers ("OEMs") was expected to create a supply-capacity-constrained market, resulting in OEMs being selective and potentially declining to bid on work. OPG subsequently assessed its Renewable Generation hydroelectric refurbishment requirements over the coming years and confirmed that these market conditions posed a material risk to the execution of its future refurbishment program (refer to Ex. F1-1-1 and Ex. L-D1-Staff-065).

To address this risk and facilitate the execution of the hydroelectric refurbishment program, OPG explored a longer-term, collaboration-oriented contracting approach to secure supplier capacity. OPG requested submissions from the hydroelectric OEMs to validate market dynamics and to assess supplier interest and capability. OPG reviewed the submissions and considered the market dynamics in developing the procurement strategy.

OPG then conducted a competitive procurement with the hydroelectric OEMs, followed by extensive commercial negotiations to secure supplier capacity through long-term agreements, while maintaining value for money considerations. The agreements were awarded to two OEMs, while the remaining OEM was not advanced as part of the competitive outcome.

b) Refer to Ex. L-D1-Staff-065. Due to the size of the agreements, summaries have been provided, commensurate with OPG's summary of the DNNP Integrated Project Agreement provided in Ex. D2-4-3.

SEC Interrogatory #149

Interrogatory

Reference:
F1-1-1, p. 11-12

Question(s):

Please provide a breakdown, by year and by component, of the $5.7M of incremental costs necessary to comply with the 2019 amendments to the Fisheries Act.

Response

As stated in Ex. F1-1-1, Section 3.2.3.2, although the Fisheries and Oceans Canada ("DFO") authorization conditions are currently unknown, they are expected to include construction or alteration of fish habitat and/or potential facility alterations. Investments to address DFO compliance activities in the 2027-2031 forecast period have been included in the unallocated portfolio (refer to Ex. D1-1-2, Table 5b).

Refer to Chart 1 for a breakdown of costs by year between labour and non-labour. Non-labour includes technical and consultative support required for the purpose of conducting assessments, compiling applications, and creating offset designs.

Chart 1
Annual Incremental Fisheries Act Authorization Costs 2026-2031 ($M)

Component	2026	2027	2028	2029	2030	2031	Subtotal
Labour	0.5	0.8	0.8	0.4	0.4	0.0	2.8
Non-labour	0.5	1.0	0.9	0.3	0.2	0.0	2.9

SEC Interrogatory #150

Interrogatory

Reference:
F1-1-1, p. 15

Question(s):

Please provide a copy of the OPG/Hydro-Québec O&M Agreement and the RG Excellence Plan.

Response

The OPG/Hydro-Québec Operation and Maintenance Agreement is provided in Attachment 1 (confidential).

The 2026-2028 RG Excellence Plan is provided in Attachment 2.

EXECUTION VERSION

OPERATION AND MAINTENANCE AGREEMENT

This operation and maintenance agreement (the "**Agreement**") is made as of the 30th day of May, 2019

between

HYDRO-QUÉBEC, a body politic and corporate, duly incorporated and regulated by the *Hydro-Québec Act* (R.S.Q. Chapter H-5) having its head office and principal place of business at 75 René-Lévesque Blvd. West, Montréal, Province of Québec H2Z 1A4 (hereinafter referred to as **"HQ"**)

and

ONTARIO POWER GENERATION INC., a corporation organized under the laws of the Province of Ontario and having its head office and principal place of business at 700 University Avenue, Toronto, Province of Ontario M5G 1X6 (hereinafter referred to as **"OPG"**)

and individually referred to as the "**Party**" and collectively as the "**Parties**".

WHEREAS:

A. HQ and OPG (or their respective predecessors in interest) have entered into various agreements (the "**Chats Falls Agreements**") relating to the Chats Falls GS (as defined below), including but not limited to:

1. the Joint Development Agreement between The Hydro-Electric Power Commission of Ontario and Chats Falls Power Company (now known as Ottawa Valley Power Company ("**OVPC**")) dated February 15, 1930 (the "**Joint Development Agreement**");

2. the Operating Services Agreement between Ontario Hydro and OVPC dated August 12, 1977 (the "**Operating Services Agreement**");

3. the Agreement between Ontario Hydro and La Compagnie D'Énergie De La Vallée de L'Outaouais (French name of the entity now known as "OVPC") dated May 1990 (the "**Maintenance Building Agreement**");

4. the Operation and Energy Accounting Agreement no. QO-S8 between HQ and Ontario Hydro replacing a March 17, 1980 agreement between the same parties and dated July 18, 1994 ("**QO-S8 Agreement**");

5. the Chats Falls Agreement between HQ and OPG dated April 8, 2003 which, *inter alia,* modified the procedures and methods of scheduling unit

operation and energy accounting at the Chats Falls GS (the "**2003 Chats Falls Agreement**");

6. the Enabling Agreement between HQ and OPG dated December 1, 2004 and effective December 23, 2004 which, *inter alia*, amends and supplements, as the case may be, the 2003 Chats Falls Agreement and the QO-S8 Agreement (the "**Enabling Agreement**"); and

7. the T30 Transformer Purchase and Sale Agreement between OPG and HQ (dated July 13, 2004) (the "**T30 Transformer Purchase and Sale Agreement**").

B. Pursuant to the *Power Commission Amendment Act, 1973*, The Hydro-Electric Power Commission of Ontario became Ontario Hydro in 1974.

C. Pursuant to Schedule A of the *Energy Competition Act, 1998* (entitled the *Electricity Act, 1998*) and in furtherance of the restructuring of the electricity marketplace in the Province of Ontario, the Government of the Province of Ontario transferred all of the right, title and interest of Ontario Hydro in generation stations located in the Province of Ontario, including the Chat Falls GS, to OPG on April 1, 1999.

D. Pursuant to an assignment agreement dated October 30, 2002, OVPC has assigned to HQ all its properties, right, title and interest in agreements relating to the Chats Falls GS.

E. Pursuant to an Emphyteutic Lease from the Government of the Province of Québec on the one hand and a lease from the Government of the Province of Ontario on the other hand, each of HQ and OPG are entitled to the use of one-half of the water available for power production at Chats Falls GS.

F. The Chats Falls GS comprises, *inter alia*, eight generating units, four of which (known as units 2 – 5) are owned by OPG and four of which (known as units 6 – 9) are owned by HQ; three transformer banks, two of which (known as T10 and T20) are owned by OPG and one of which (known as T30) is owned by HQ; and certain works that are jointly owned by OPG and HQ. Pursuant to the 2003 Chats Falls Agreement OPG operates the Chats Falls GS.

G. The Parties wish to terminate the Operating Services Agreement and the Maintenance Building Agreement and replace them with this Agreement.

H. In 2006 the Parties agreed that the annual cost of operating HQ's four generating units is [redacted] (the "**Base Amount**"), to be indexed for each year after 2006. Schedule E shows the annual amounts paid by HQ to OPG on account of the Base Amount for each of the years 2006 to and including 2018 and the associated unpaid indexation portion.

NOW THEREFORE in consideration of the mutual covenants and agreements contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. **Definitions**

In this Agreement:

(a) "**2003 Chats Falls Agreement**" has the meaning set forth in paragraph A(5) of the preamble.

(b) "**Activities**" means the HQ GU Operation, the Operation and Maintenance and the Projects.

(c) "**Agreement**" means this operation and maintenance agreement, including the schedules hereto.

(d) "**Base Amount**" has the meaning set forth in paragraph H of the preamble.

(e) "**Budgets**" means, collectively, the Operation and Maintenance Budgets and the Project Budgets and "**Budget**" means any one of them.

(f) "**Chats Falls Agreements**" has the meaning set forth in paragraph A of the preamble.

(g) "**Chats Falls GS**" means the Chats Falls generating station on the Ottawa River and installed facilities consisting of eight generating units fed by a common forebay and related works, all as shown in Schedule B hereto and as described in Section 1 (Introduction) of the **QO-S8 Agreement**.

(h) "**Chats Falls Operating Committee**" has the meaning set forth in Section 8.a.

(i) "**Common Works**" means Common Equipment and Joint Works as defined under the Joint Development Agreement, and for purposes of this Agreement includes, but is not limited to, works and equipment located at Chats Falls GS used to support the generating units of the Chat Falls GS, as described in Table 1 of Schedule A hereto and as shown in blue in Schedules B and C hereto.

(j) "**Contract Year**" means any calendar year during the Term.

(k) "**CPI**" means the consumer price index not seasonally adjusted for "All Items" published or established by Statistics Canada (or its successors) in relation to the Province of Ontario.

(l) "**Effective Date**" has the meaning set forth in Section 23.

(m) "**Enabling Agreement**" has the meaning set forth in paragraph A(6) of the preamble.

(n) "**Force Majeure Event**" means an event that is beyond the reasonable control of a Party, is not preventable by reasonable precautions, and cannot reasonably be circumvented by the Party through the use of commercially reasonable efforts; including by way of example but without limitation, an earthquake, tornado, fire, hurricane, flood, lightning or other act of God, explosion, insurrection, war (whether declared or not), revolution, invasion, riot, sabotage, terrorism, catastrophic computer failure caused by a computer virus, epidemic, disruption of transportation facilities caused by flood, major snow storm or other catastrophe, changes in law, strike, lock out and other industrial disputes.

(o) "**Guideline**" means a revision to a current Budget agreed by the Parties in accordance with Section 11.b.

(p) "**GU Operation Charge**" has the meaning set forth in Section 15.a.i.

(q) "**HQ GU Operation**" means all activities related to the operation of HQ's four generating units forming part of the Separate Works that are performed on a remote basis.

(r) "**HQ T30**" means the works at the Chats Falls GS that are referred to in Table 2 of Schedule A hereto and shown in green in Schedule D hereto, all of which are owned entirely by HQ. HQ T30 includes but is not limited to the following: T30 transformer bank including all attached instrumentation, current transformer bushings used for T30 revenue metering, the T30-Q4C motor operated disconnect switch and low voltage T30-X and T30-Y disconnects.

(s) "**Insurance Policies**" has the meaning set forth in Section 20.a.

(t) "**Interest Rate**" means, for any date, the reference lending interest rate per annum charged by Bank of Nova Scotia (or such other Canadian bank as OPG may give notice in writing to HQ from time to time) on Canadian dollar commercial loans made in Canada (known as the "prime rate"), plus two percent (2%).

(u) "**Joint Development Agreement**" has the meaning set forth in paragraph A(1) of the preamble.

(v) "**Maintenance Building**" means the maintenance building of the Chats Falls GS owned exclusively by OPG which is on the Ontario side of the provincial border and referred to in Table 5 of Schedule A.

(w) "**Maintenance Building Agreement**" has the meaning set forth in paragraph A(3) of the preamble.

(x) "**Operation and Maintenance**" means all ordinary or routine operation and maintenance activities to be performed on the Works, including repairs, and any other activity which is not otherwise a Project hereunder, and excluding the HQ GU Operation but including, for avoidance of doubt, all activities related to the operation of HQ's four generating units forming part of the Separate Works that are performed onsite at Chats Falls GS.

(y) "**Operation and Maintenance Budget**" means an annual budget for Operation and Maintenance to be carried out in any given calendar year.

(z) "**Operating Services Agreement**" has the meaning set forth in paragraph A(2) of the preamble.

(aa) "**OPG / HQ Operating Committee**" means the operating committee defined in Article 3 of the Enabling Agreement.

(bb) "**OPG T10 and T20**" means the works at the Chats Falls GS that are referred to in Table 3 of Schedule A hereto and shown in pink in Schedule D hereto, all of which are owned entirely by OPG. OPG T10 and T20 includes but is not limited to the following: T10 and T20 transformer banks including all attached instrumentation, associated motor operated disconnect switches and any installed low voltage T10 and/or T20 disconnects.

(cc) "**OVPC**" has the meaning set forth in paragraph A(1) of the preamble.

(dd) "**Projects**" means projects involving non-recurring costs and expenditures of a capital or non-standard investment nature to be carried out on any portion of the Works.

(ee) "**Project Budget**" means an itemized annual budget for one or more Projects to be carried out in any given calendar year.

(ff) "**QO-S8 Agreement**" has the meaning set forth in paragraph A(4) of the preamble.

(gg) "**Separate Works**" means the Separate Works as defined under the Joint Development Agreement, and for purposes of this Agreement includes, but is not limited to, generating units of the Chat Falls GS and associated equipment, all revenue metering equipment installed on T10, T20 and T30, and all associated equipment such as capacitive voltage transformers (CVTs), free standing current transformers (CTs), and supporting communication network (excluding HQ T30 CTs used for revenue metering and those items listed on Exhibit A of the T30 Transformer Purchase and Sale Agreement), all of which are owned by either of OPG or HQ, as described in Table 4 of Schedule A hereto and as shown in pink in Schedule C hereto. For the sake of clarity, the Separate Works assets include equipment up to but not including the low voltage bushing of the T10 transformer and the low voltage disconnect switches of the T20 and T30 transformers, provided

however that if low voltage disconnect switches were to be added to the T10 transformer, then the demarcation point would be similar to that of the T20 and T30 transformers.

(hh) "**T30 Transformer Purchase and Sale Agreement**" has the meaning set forth in paragraph A(7) of the preamble.

(ii) "**Term**" has the meaning set forth in Section 23.

(jj) "**Third Party Claim**" means a claim, demand, action, suit or legal proceeding made or brought by a third party against a Party.

(kk) "**Working Team**" has the meaning set forth in Section 9.

(ll) "**Works**" is used in this Agreement as a general short form term of convenience, and means any combination of the Common Works, Separate Works, HQ T30, OPG T10 and T20 and the Maintenance Building as required or permitted by the context of the section of the Agreement in which it is used. For the purposes of Sections 3 and 12, "Works" also refers to the Joint Works, Separate Works and Common Equipment, as defined in the Joint Development Agreement.

2. **Termination of Agreements**

The Operating Services Agreement and the Maintenance Building Agreement shall terminate as of the Effective Date. As soon as possible following the Effective Date, OPG shall issue a final invoice to HQ for all amounts owed by HQ to OPG pursuant to the aforesaid agreements and HQ shall pay such amounts in accordance with the provisions of Section 19. Subject to the payment of the amounts indicated in the aforementioned final invoice, each of OPG and HQ hereby give the other a full and final release and discharge from any and all claims, demands, obligations, liabilities, cause or causes of action, whensoever arising and occurring at any time up to and through the date hereof, whether known or unknown, suspected or unsuspected, liquidated or unliquidated, matured or unmatured, fixed or contingent, that arise out of or relate to the Operating Services Agreement and the Maintenance Building Agreement.

3. **Ownership of Works**

Nothing in this Agreement is intended to affect the rights of ownership and title of each of the Parties to the Works as set forth in the Joint Development Agreement.

4. **Operation and maintenance of the Chats Falls GS**

OPG shall perform the Activities so as to maintain the Chats Falls GS in service and in good repair.

5. **Activities Standards**

a. Subject to the terms of this Agreement and to the terms of any budget restrictions or other arrangements agreed to by the Parties from time to time, OPG shall carry out the Activities: (i) as a prudent and diligent generating station operator would do in the circumstances and in accordance with sound utility practice; (ii) in a manner reflecting the principles of the 2003 Chats Falls Agreement as amended or replaced from time to time, (iii) in compliance with all applicable laws and regulations of the Provinces of Quebec and Ontario and of Canada and all other principles or rules agreed to by the Parties from time to time including without limitation the rules established by the Independent Electricity System Operator (the "**IESO**") governing the IESO controlled grid.

b. Without limiting the generality of the foregoing, OPG agrees to perform the Activities (i) without discrimination based on ownership by either HQ or OPG of any portion of the Works and (ii) at the same level and upon the same standards used by OPG in maintaining and operating OPG's own equipment at the Chats Falls GS.

c. In addition to any other notification obligation hereunder, in the regular meetings of the Working Team OPG shall keep HQ apprised of the performance of the Activities and shall notify HQ of any event or matter which has occurred or is reasonably expected to occur affecting the Works in any material way, including without limitation any existing or potential dispute or Third Party Claim in respect of the Chats Falls GS.

6. **Sharing of Energy Output**

Since the Activities are carried out on the Works as a whole, regardless of ownership of the various components of the Works, the energy output of the Chat Falls GS, except as otherwise provided in Sections 11 and 12 hereof, will be shared equally by both Parties, in accordance with the terms of the 2003 Chats Falls Agreement as amended or replaced from time to time, regardless of the ownership of any portion of the Works that may be partly or fully out of service as a result of the performance of any Activities or for any other reason.

7. **OPG T10 and T20**

Notwithstanding any other provision in this Agreement, Sections 8, 9, 11, and 14, shall not apply to any Activities in respect of OPG T10 and T20.

8. **Chats Falls Operating Committee**

a. Duties

For the purposes of this Agreement, the Parties have established and will maintain an operating committee (the "**Chats Falls Operating Committee**") consisting of two members (one appointed by each Party) and two alternates (one appointed by each Party). While both the member and the alternate appointed by each of the Parties may participate at meetings of the Chats Falls Operating Committee, alternates may only vote in the absence of their respective member. A Party may change its member or its alternate at any time by notifying the other Party in writing.

The Chats Falls Operating Committee is authorized on behalf of the Parties to approve budgets and schedules for Operation and Maintenance and Projects (as further described in Section 11), to investigate the need for additional maintenance and investments, and to assess the need for changes in the method of operation of the Common Works, the Separate Works and HQ T30, relying on advice from engineers and other personnel within the respective Parties, as required.

The Chats Falls Operating Committee reports to the OPG/HQ Operating Committee regarding all matters pertaining to the Chats Falls GS, as provided for in Article III of the Enabling Agreement.

The Chats Falls Operating Committee will meet at least once each year.

The Chats Falls Operating Committee will record minutes of all of its meetings. Final minutes shall be approved by the members (or alternates, if applicable) of the Chats Falls Operating Committee and will be sent to the OPG/HQ Operating Committee.

When needed, the members may, by agreement, invite one or more non-members to attend the Chats Falls Operating Committee meetings.

b. Decisions

All decisions of the Chats Falls Operating Committee in respect of matters within its jurisdiction shall be unanimous. If the Chats Falls Operating Committee is unable to reach agreement, then the matter shall be referred to the OPG/HQ Operating Committee.

9. **Working Team**

A working team comprised of employees or resources of each Party (the "**Working Team**") shall meet regularly throughout the year to review programs, costs and

schedules and to follow up on the implementation of Operation and Maintenance and Projects. The Working Team's reviews shall include, without limitation, anticipated and actual variations of approved Budgets.

10. **Expenses**

Each Party shall pay the expenses of its member or alternate on the Chats Falls Operating Committee and of its employees or resources on the Working Team.

11. **Budget Approvals and Variances**

a. Establishing annual Budgets: Annually, the Chats Falls Operating Committee will prepare an Operation and Maintenance Budget and one or more Project Budgets for the following calendar year, based on information and recommendations of the Working Team (which recommendations shall incorporate all information as may be reasonably necessary to allow the Chats Falls Operating Committee to make appropriate determinations regarding expenditures). Each member of the Chats Falls Operating Committee will submit the proposed Operation and Maintenance Budget and proposed Project Budget(s) to the Party having appointed such member by July 1st of the calendar year preceding the year for which such Budgets are being proposed. A Party's approval regarding proposed Budgets shall not be unreasonably withheld. The proposed Budgets will be reviewed by the appropriate approval authorities of each Party and the approved Budgets will be returned to the Chats Falls Operating Committee, on a commercially reasonable efforts basis, by December 1st of the year preceding the year to which the Budgets relate.

b. Variations of approved Budgets: All duly budgeted Operation and Maintenance and Projects shall be completed by OPG without any additional approval being required from HQ.

Any additional non-budgeted Operation and Maintenance which individually, or in the aggregate, have an estimated net cost that does not exceed an amount equal to 10% of the Operation and Maintenance Budget shall also be completed by OPG without any additional approval being required from HQ. An Operation and Maintenance Budget Guideline shall be required for any new Operation and Maintenance which individually, or in the aggregate, have an estimated net cost exceeding an amount equal to 10% of the Operation and Maintenance Budget. The 10% limit set forth above may be revised by the Chats Falls Operating Committee in accordance with each Party's corporate governance policies and procedures.

A Project Budget Guideline shall be required in the event: (i) of any new Project requiring spending in the then current Budget year that is not listed

in the Budget, or (ii) that the estimated cost for a Budget year of a Project that is proceeding to execution is expected to exceed the approved Project Budget for the Budget year by an amount that is greater than 10% of the original approved Project Budget amount. OPG shall not commit any (further) resources to the subject Project prior to the approval of the Guideline. The 10% limit set forth above may be revised by the Chats Falls Operating Committee in accordance with each Party's corporate governance policies and procedures.

If a Guideline is required pursuant to this Section 11.b, OPG shall promptly submit a proposed Guideline to the Working Team. The Working Team members will seek approval of the Guideline in accordance with their Party's respective governance.

For the purposes of this Section 11.b, "**net cost**" means the share of the costs payable by HQ in respect of the applicable matter.

c. Working Team Budget Reviews: The Working Team will review and/or analyze year to date variations from approved Budgets on a "work package by work package" basis, to distinguish variations that must be implemented during a given current year from variations that could be corrected in a subsequent calendar year, allowing the Working Team to propose necessary funding adjustments to the business plan. As a general principle, every effort will be made to defer other recurring Operation and Maintenance when a permanent, unfavourable variation from an approved Budget is confirmed. In the event that the deferral of a proposed variation is not an option, the proposed variation will be approved (in accordance with each Party's corporate governance policies and procedures) on an exception basis with the expectation that the following year's expenditures will return to levels previously proposed by the Working Team.

The Working Team will also review year-end projections on a "work package by work package" basis to feed into both HQ's and OPG's overall forecast and to prioritize work. This process will also provide the opportunity to manage other current year costs so that the overall impact on the whole program is minimal and spending is as close to the Budgets as possible.

d. If a Party is silent regarding (i) the matters referred to in Section 11.a beyond December 31st of the relevant calendar year, or (ii) any of the matters referred to in Section 11.b for a period of three (3) months or more from the date OPG submits the Guideline to the Working Team, such Party shall be deemed to have elected not to approve the relevant Budget(s) or Budget variation(s) or to pay for its equal share of the relevant Operation and Maintenance Activity and/or Project. If a Party elects (or is deemed to elect) not to approve and/or pay its equal share of any Project or Operation and

Maintenance Activity, and in either case this affects the immediate generating capability of any of the Separate Works owned by such Party, then the relevant generating unit(s) belonging to such Party shall be deemed to be completely retired and the output of the Chats Falls GS shall be shared on the basis of the ratio of the number of generating units either Party has available for service to the total number available for service. If a Party elects (or is deemed to elect) not to approve and/or pay its equal share of any Project or Operation and Maintenance Activity on the other Party's Separate Works, the other Party may pay such costs and the energy output from such generating unit shall belong to the Party that has paid for such work.

e. If a Party is silent regarding (i) the matters referred to in Section 11.a beyond December 31st of the relevant calendar year or (ii) any of the matters referred to in Section 11.b for a period of three (3) months or more from the date OPG submits the Guideline to the Working Team, and its approval is required in relation to a proposed Project or Operation and Maintenance Activity on Common Works or Separate Works (other than as provided in Section 11.d), the issue shall be referred to the OPG/HQ Operating Committee.

12. **Force Majeure**

If either Party is prevented from performing any of its material obligations under this Agreement because of the occurrence of a Force Majeure Event, then, except for any payment obligation, such Party shall not be bound to perform its obligations under this Agreement to the extent that the fulfillment of its obligations is prevented by such event. Such Party shall be prompt and diligent in taking commercially reasonable measures to remove, overcome and/or mitigate any such cause or causes of interruption derived from the Force Majeure Event. Upon request, the Party that is not affected by the Force Majeure Event will render any commercially reasonable assistance it might be expected to render to the other Party. Without limiting the generality of the foregoing, in the event of a strike by OPG's employees and/or subcontractors, OPG:

a. will use commercially reasonable efforts to provide alternative resources to operate the Common Works, and

b. consents to HQ operating and maintaining the Separate Works owned by HQ and HQ T30 throughout the duration of such strike, if HQ so desires, provided that any such operation and maintenance shall be: (i) in compliance with any applicable laws and rules and the principles of this Agreement; (ii) at HQ’s sole cost and expense; and (iii) subject to HQ’s indemnification obligation set forth in Section 21.c, provided that using such commercially reasonable efforts or providing such consent is not in violation of any applicable laws or regulations, as determined by OPG

counsel. During any such time that HQ operates and maintains its Separate Works and HQ T30, HQ shall own 100% of the energy output from such Works.

Promptly upon obtaining knowledge thereof and in any event no later than 10 days therefrom, a Party shall notify the other Party in writing that a Force Majeure Event has occurred or is reasonably expected to occur.

13. **Access by HQ**

HQ shall at all times have free access to the Chats Falls GS and everything therein contained relating to this Agreement. HQ shall also have access at all reasonable times to all books, accounts and records of OPG concerning anything pertaining to this Agreement. Requests for access to books, accounts and records shall be made to OPG's member on the Chats Falls Operating Committee.

14. **Records**

a. OPG shall keep records, in accordance with OPG's record retention policies, covering all matters of essential importance hereunder and shall furnish such information to HQ in a format and at a time mutually agreed to by the members of the Chats Falls Operating Committee. In addition, OPG shall furnish, at HQ's sole expense, any special reports concerning any matters related to this Agreement and/or its implementation which may be requested by HQ during the Term of this Agreement.

b. OPG shall establish and maintain records, in accordance with OPG's record retention policies, in such form as will show in detail all receipts and expenditures and the costs of all Activities performed pursuant to this Agreement so that the same may be reviewed by HQ.

15. **Cost allocation of Activities**

a. **HQ GU Operation**

i. HQ shall pay an annual fee to OPG for performing the HQ GU Operation (the "**GU Operation Charge**"). The GU Operation Charge for any given Contract Year shall be calculated as follows:

[redacted]

where:

[redacted] (rounded to the nearest cent);

[redacted] (rounded to the nearest cent);

[redacted]

[redacted]

ii. The GU Operation Charge for the first Contract Year of this Agreement, being from January 1, 2019 to December 31, 2019, is [redacted]. The GU Operation Charge for the first Contract Year of this Agreement was calculated in accordance with the provisions of Section 15.a.i. Schedule E shows annual GU Operation Charges from 2007 to 2018.

iii. The Parties further acknowledge that HQ shall pay, upon execution of this Agreement, an amount of [redacted] representing full and final payment of the unpaid indexation portion of the GU Operation Charge payable to OPG for calendar years 2007 to 2018, as further detailed in Schedule E.

iv. HQ agrees to pay the GU Operation Charge in the manner set forth in Section 19.

b. **Operation and Maintenance**

All costs of Operation and Maintenance shall be calculated and payable according to the principles and in the manner set forth in Sections 18 and 19 hereof and shall be shared between OPG and HQ as follows:

i. <u>On the Common Works and Separate Works</u>

The costs of Operation and Maintenance relating to the Common Works and Separate Works shall be shared equally between OPG (50%) and HQ (50%).

ii. <u>On the Maintenance Building</u>

All costs of Operation and Maintenance relating to the Maintenance Building and land associated therewith shall be borne by OPG (63%) and by HQ (37%).

iii. On the HQ T30

The costs of Operation and Maintenance relating to the HQ T30 and all items listed in Exhibit A of the T30 Transformer Purchase and Sale Agreement shall be paid by HQ.

iv. On the OPG T10 and T20

OPG shall be responsible for the costs of Operation and Maintenance relating to the OPG T10 and T20.

c. **Cost allocation of Projects**

All costs of Projects shall be calculated and payable according to the principles and in the manner set forth in Sections 18 and 19 hereof and shall be shared between OPG and HQ as follows:

i. The cost of Projects pertaining to Common Works or Separate Works shall be borne by OPG (50%) and HQ (50%), regardless of which Party owns the subject Works.

ii. The cost of Projects pertaining to HQ T30 shall be borne entirely by HQ.

iii. The cost of Projects pertaining to OPG T10 and T20 shall be borne entirely by OPG.

iv. The cost of Projects pertaining to the Maintenance Building and land associated therewith shall be borne by OPG (63%) and HQ (37%).

16. **Maintenance Building**

In the event this Agreement, the Joint Development Agreement and the 2003 Chats Falls Agreement are terminated without being replaced by an agreement or agreements covering substantially the same subject matters, then OPG agrees to refund to HQ within ninety (90) days of the termination of the above referenced agreements the unamortized portion of HQ's capital cost contribution with respect to the Maintenance Building provided the Maintenance Building will continue to be used after the termination of the above mentioned agreements. The Parties agree that for the purposes of this Agreement, the Maintenance Building is being fully depreciated over a period of thirty (30) years on a straight line depreciation basis, commencing June 1, 1991. HQ’s share of the undepreciated capital cost of the Maintenance Building as of June 1, 1991 was $1,492,686.00.

17. **Administration of joint lands**

All costs of administration and maintenance of the "joint lands" will continue to be shared as provided in the Joint Development Agreement. All revenues received from leases and rentals of the "joint lands" shall be shared equally between OPG and HQ.

18. **Costs Allocated to HQ**

a. **On Operation and Maintenance**

HQ's share of Operation and Maintenance expenditures shall be based on the actual Operation and Maintenance costs as determined by OPG, and shall, without limiting the generality of the foregoing, include the items described below, without duplication.

i. All actual costs of materials, supplies, sundries, external contracts, tools, stores, apparatus, machinery and equipment in connection with the Operation and Maintenance.

ii. All salaries, wages and other remuneration including prevailing payroll burdens of all persons employed in connection with the Operation and Maintenance, to which shall be added an overhead rate of 100% to burdened operating and maintenance trade labour rates (collectively, "**Labour Costs**") which are established annually for recovery of administration costs. These costs include the following:

I. The overhead rate which is intended to recover a portion of the cost of OPG's functional support staff employed in connection with the Operation and Maintenance, such as Eastern Operations and OPG corporate functions. Eastern Operations is an operational division of OPG with responsibility for Chats Falls GS and other stations. Existing (as at the date of this Agreement) functional support departments include: Eastern Operations management and production support such as programming and project management, and OPG corporate functions such as controllership, engineering, environment, real estate, information technology and law divisions.

II. Administration costs which include the recovery of supervisory and administrative support functions of the Chats Falls GS Production group (a subset of the Eastern Operations that is responsible for Chats Falls GS), indirect activities (e.g. training, meetings, and travel), transport and work equipment.

III. Administration costs which include the recovery of insurance premiums and certain infrastructure and communications costs related to the operation of Chats Falls GS including, but not limited to: telephone systems and information networks and equipment which are not included in the Eastern Operations budget or costs.

iii. The Labour Costs for all special engineering, legal, accounting and other special services approved by HQ and rendered by employees and officers of OPG who are not regularly employed in Eastern Operations, as agreed to by the Chats Falls Operating Committee.

b. **On Projects**

HQ's share of Project expenditures (the "**HQ Project Cost**") shall be based on the actual cost of the Project as determined by OPG. In addition to HQ Project Cost, HQ shall pay to OPG an amount representing a portion of OPG's support costs associated with the administration and execution of the Project (the "**HQ Overhead Amount**") that shall be equal to 10% of the HQ Project Cost (the "**Overhead Rate**"), provided that the Chat Falls Operating Committee may revise the Overhead Rate in accordance with each Party's corporate governance policies and procedures.

19. **Invoicing**

All invoices to be sent by OPG pursuant to this Agreement shall incorporate all information as may be reasonably necessary to determine amounts due.

As a general principle, only charges, costs and expenditures which form part of an approved Budget (or any permitted variation thereto) will be invoiced by OPG to HQ.

Unless otherwise provided in this Agreement, HQ shall pay to OPG the costs allocated to HQ under Section 15 in Canadian dollars on a monthly basis. Monthly invoices shall be issued by OPG to HQ and shall be paid by HQ within thirty (30) days from the date of receipt by HQ of any given invoice. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate, calculated from and including the due date up to but excluding the date the delinquent amount(s) and accrued interest is/are paid in full.

In the event HQ reasonably disputes the amount of any invoice, whether in whole or in part, it shall notify OPG of such dispute no later than thirty (30) days from receipt of the invoice, indicating to OPG the amount of such invoice subject to dispute and providing reasonable particulars of such dispute. In such event, the Parties shall use their reasonable commercial efforts to resolve such dispute within a reasonable period of time, not exceeding sixty (60) days from the date of such

notice. HQ shall nonetheless be obligated to make timely payment of any non-disputed amount. If it is ultimately determined that the disputed amount, in whole or in part, was properly payable to OPG, then HQ shall promptly pay OPG such amount with interest accruing at the Interest Rate from the payment due date of the invoice in accordance with this Section 19.

20. **Insurance**

a. During the Term of this Agreement, OPG shall secure and maintain in force the following insurance coverage, with deductibles as would be maintained by a prudent operator of a facility of similar size, function and location, with respect to the Chats Falls GS:

i. All risks insurance for the full replacement cost value of the Chats Falls GS (including earthquake, flood and sewer back-up coverage or endorsements);

ii. Loss of revenue (business interruption) insurance on the income derived from Chats Falls GS with a period of indemnity of 18 months;

iii. Boiler and machinery insurance on a comprehensive basis; and

iv. Commercial general liability insurance with a limit of liability of not less than ten million dollars ($10,000,000.00) per accident or occurrence in or for the Chats Falls GS and the lands related or adjacent thereto, including but not limited to bodily injury and personal injury liability, property damage, products liability, completed operations liability, owners and contractors protective liability, blanket contractual liability, premises liability, broad form property damage, employers liability, including coverage for injury, pollution liability on at least a sudden and accidental basis, and loss or damage due to pollution arising from "hostile fires",

(the insurance policies listed in (i) through (iv) being, collectively, the "**Insurance Policies**").

b. The Insurance Policies shall cover both OPG and HQ as co-insureds and OPG shall deliver to HQ copies of any endorsements evidencing such co-insured status following OPG's receipt of same. OPG shall use commercially reasonable efforts to ensure that the Insurance Policies are secured with one or more insurers licensed to sell commercial insurance under the laws of Ontario and Quebec and that, as of the policy renewal date, each insurer has an "A-" rating or better by A.M. Best or an equivalent rating agency.

c. OPG shall, from time to time, instruct a licensed appraiser to perform an appraisal of Chats Falls GS for the purposes of determining its replacement cost value, and the period between each such appraisal shall not exceed 10 years, unless otherwise agreed to by OPG and HQ. OPG shall provide a copy of each appraisal report to HQ promptly following OPG's receipt of same. The all risks insurance coverage secured by OPG pursuant to Section 20.a.i hereof shall cover the full replacement cost value as indicated in the most recent appraisal report plus annual indexation.

d. On the Effective Date and on an "as soon as practicable" basis for each Contract Year thereafter, OPG shall provide to HQ an insurance certificate evidencing compliance with Section 20.a hereof as well as a summary of HQ's share of the insurance premiums payable (including the applicable premium rate) under the Insurance Policies for such Contract Year.

e. For the avoidance of doubt, it is understood that the cost of securing and maintaining insurance coverage, including the payment of any associated deductible, for Chats Falls GS in accordance with this Section 20 shall be included in the Operation and Maintenance Budget and shared between OPG and HQ in accordance with Section 15.b.i hereof.

f. HQ hereby acknowledges receipt of a summary of the deductibles that are applicable under the Insurance Policies in effect as of the date hereof (the "**Deductibles**") and that the Deductibles comply with the standard set out in Section 20.a. OPG shall advise HQ through the Working Team of any material changes to the Deductibles during the Term.

21. **Claims and Indemnification**

a. In case any Third Party Claim shall be made against OPG or HQ in connection with the performance of a Party's obligations hereunder, OPG or HQ, as the case may be, shall promptly notify the other Party thereof. Each Party shall render to the other all reasonable assistance for such purposes of defending such claim. Subject to this Section 21, all costs, expenses and damages in connection with such claims shall be shared equally between the Parties.

b. Subject to the provisions of the Chats Falls Agreements OPG shall indemnify, defend and hold harmless HQ and its affiliates, directors, officers, employees, agents and representatives (collectively, the "**HQ Indemnified Persons**") from and against any loss, liability, obligation, claim and damages (including reasonable legal fees) (collectively, the "**Damages**") suffered by, imposed upon or asserted against any HQ Indemnified Person, as a result of, in respect of, connected with or arising out of Third Party Claims for personal injury (including death) and property

damage to the extent caused solely by the gross negligence or wilful misconduct of OPG.

c. HQ shall indemnify, defend and hold harmless OPG and its affiliates, directors, officers, employees, agents and representatives (collectively, the "**OPG Indemnified Persons**") from and against any Damages suffered by, imposed upon or asserted against any OPG Indemnified Person as a result of, in respect of, connected with or arising out of any operation or maintenance of any Works by or on behalf of HQ during any strike by OPG's employees or subcontractors.

d. Promptly upon obtaining knowledge thereof, and in any event no later than one (1) month therefrom, a Party shall notify the other Party of any cause which has given or could reasonably be expected to give rise to indemnification under this Section 21.

e. If any Third Party Claim shall be asserted against a Party in respect of which the Party proposes to demand indemnification hereunder, then the other Party shall have the right, upon reasonable prior written notice, to defend (and to control the defense of) the Third Party Claim at its own cost and expense with counsel of its choice, provided that the indemnified Party shall at all times have the right to fully participate in the defence at its own expense and with counsel of its choice.

f. The indemnifying Party shall not be permitted to compromise and settle or to cause a compromise and settlement of any Third Party Claim without the prior written consent of the indemnified Party, such consent not to be unreasonably withheld.

g. If the indemnifying Party fails, within thirty (30) days after having been apprised of the Third Party Claim, to give notice of its intention to defend the Third Party Claim in accordance with this Section 21, then the indemnifying Party shall be deemed to have waived its right to defend the Third Party Claim and the indemnified Party shall have the right (but not the obligation) to undertake the defence of the Third Party Claim and compromise and settle the Third Party Claim for the account and at the risk and expense of the indemnifying Party. In such event, the indemnifying Party shall at all times have the right to fully participate in the defence of such Third Party Claim at its own expense and with counsel of its choice.

22. **Inconsistency with Joint Development Agreement or 2003 Chats Falls Agreement**

Nothing in this Agreement shall relieve OPG or HQ from any obligation under the Joint Development Agreement or the 2003 Chats Falls Agreement, provided that in the event of an inconsistency between this Agreement and the Joint Development

Agreement or the 2003 Chats Falls Agreement and unless otherwise specified herein, this Agreement shall prevail.

23. **Term**

This Agreement shall be deemed to come into effect as of January 1, 2019 (the "**Effective Date**") without regard to the date of its signature by the Parties and shall remain in effect indefinitely (the "**Term**"). Either Party may terminate this Agreement at any time upon three (3) years' written notice to the other Party without any penalty or liability whatsoever. For avoidance of doubt, termination of this Agreement does not, unless expressly stated otherwise, result in the termination of any of the Chats Falls Agreements.

24. **Review of this Agreement**

Either Party may request a review of this Agreement at any time. If, as a result of such a review it is agreed that any of the provisions of this Agreement, or the practices or conduct of either Party impose a hardship or undue burden upon the other, the Chats Falls Operating Committee shall endeavour to negotiate an amendment to this Agreement which will remove such hardship or undue burden. Any proposed amendment(s) to the Agreement shall, once formulated by the Chat Falls Operating Committee, be submitted by each member of the Chats Falls Operating Committee to the Party which has appointed it, for approval by such Party's approval authorities.

25. **Notice**

Any notice, consent or other communication required herein shall be in writing and delivered by hand or by registered mail (return receipt requested), overnight courier service (receipt effective upon scheduled weekday delivery day) or given by email (receipt effective upon receipt of evidence, including email evidence that email was received before 3:00 p.m. on a business day in the Province where the recipient's office address below is located) and addressed or directed as follows:

<u>If to OPG</u>:

Lennox Generating Station
7263 Highway 33 W
PO Box 1000
Bath, Ontario
K0H 1G0
Attention: John Hefford, Vice President Regional Operations – Eastern Operations
Email: john.hefford@opg.com

If to HQ:

75 boul. René-Lévesque O.
Montréal, Qc
H2Z 1A4
Attention: Érik Bellavance, Chef Développements commerciaux
Email: Bellavance.Erik@hydro.qc.ca

Any change in the identity and/or contact details of a Chats Falls Operating Committee member and any change in the address of a Party shall be promptly communicated to the other Party in writing and any subsequent notice or communications shall be sent to such member or Party's changed address.

26. **Governing Law**

This Agreement and the rights and duties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, without regard to the principles of conflicts of law. All actions and proceedings arising out of or relating to this Agreement shall be heard and determined exclusively in a court located in the Province of Ontario.

27. **Confidentiality**

Each Party shall preserve the strict confidentiality of this Agreement and shall not disclose its terms and conditions nor any information obtained in connection therewith (collectively the "**Confidential Information**"), whether before or after the Effective Date, without obtaining the prior written approval of the other Party.

If a Party is required by law, order or judgment or by request of a regulatory agency or other governmental entity to disclose any of the Confidential Information, the legally compelled Party shall provide the other Party with prompt written notice of such request or requirement and shall cooperate with such other Party so it may seek, at its expense, an appropriate protective order or other appropriate remedy.

28. **Execution in several counterparts**

This Agreement may be executed in any number of counterparts (including by means of PDF), each of which when executed, shall be deemed to be an original and all of which together will be deemed to be one and the same instrument binding upon the Parties notwithstanding the fact that both Parties are not signatory to the original or the same counterpart. Delivery of an executed counterpart of a signature page to this Agreement electronically shall be effective as delivery of a manually executed counterpart of this Agreement.

29. **Language and prevailing version**

The Parties have elected to negotiate this Agreement in the English language. The English version of this Agreement shall prevail in the event of any discrepancy between the English version and any French version.

30. **Headings**

All headings used in the Agreement are for convenience only and do not form part of this Agreement.

31. **No assignment**

Neither Party may assign this Agreement, in whole or in part, without the prior written consent of the other Party. This Agreement enures to the benefit of and binds each of the Parties and their respective successors and permitted assigns.

[Signature page follows]

EXECUTION VERSION

IN WITNESS WHEREOF the Parties hereto have caused this Agreement to be executed attested by the signatures of their proper officers duly authorized thereto.

ONTARIO POWER GENERATION INC.

By: May 30th 2019

Name: Mike Martelli
Title: President, Renewable Generation

HYDRO-QUÉBEC

By: Signature numérique de CG3749
Date : 2019.05.24 15:02:21 -04'00'

Name: Simon Bergevin
Title: Directeur, Parquet de transactions énergétiques

SCHEDULE A
Types of Works

Table 1

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
Common Works - including but not limited to: • station service • sluice gates • bridges • roads • dam including powerhouse intake structure • log sluice • backup diesel generator • compressed air system	Common Works	OPG, HQ, or OPG and HQ	50%/50%

Table 2

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
T30 etc	HQ T30	HQ	100% HQ

Table 3

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
T10 etc	OPG T10, T20	OPG	100% OPG
T20 etc	OPG T10, T20	OPG	100% OPG
T20-T	OPG T10, T20	OPG	100% OPG
T20-B2	OPG T10, T20	OPG	100% OPG

Table 4

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
Revenue Metering including: • Revenue meters both primary and back up	Separate Works	OPG	50%/50%

• associated CVTs • associated free standing CTs • associated telecommunication devices			
G2	Separate Works	OPG	50%/50%
G3	Separate Works	OPG	50%/50%
G4	Separate Works	OPG	50%/50%
G5	Separate Works	OPG	50%/50%
G6	Separate Works	HQ	50%/50%
G7	Separate Works	HQ	50%/50%
G8	Separate Works	HQ	50%/50%
G9	Separate Works	HQ	50%/50%

Table 5

Item	**Designation**	**Ownership (refer to Schedule B)**	**Accounting Practice (refer to Schedule D)**
Maintenance Building	Maintenance Building	OPG	63% OPG/37% HQ

SCHEDULE B

Station Operating Diagram - Ownership

See attached.

[redacted]

SCHEDULE C

Station Operating Diagram – Common Works and Separate Works

See attached.

SCHEDULE D

Station Operating Diagram - Accounting

See attached.

SCHEDULE E

Application of Section 15.a from 2006 to 2018

Year	[redacted]	*Annual GU Operation Charge*	*GU Operation Charge invoiced and paid*	*Cumulative unpaid indexation portion*
2005	[redacted]			
2006	[redacted]	[redacted]	[redacted]	
2007	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]

MyBusiness | ONTARIO POWER GENERATION

Strategy & Excellence Plan | Renewable Generation 2026-2028

Our People | **Our Plant** | **Our Future**

Filters

Portfolio / Excellence Plan: Renewable Generation

Strategic Objectives | Pillars

OUR PEOPLE Drive a strong safety culture	OUR PEOPLE Foster a positive work environment	OUR PLANT Maximize equipment performance	OUR PLANT Strengthen work planning and execution	OUR FUTURE Earn the right to generate the future
Goal				
Foster a strong culture to achieve higher safety standards	Build an engaged team that embodies OPG's values	Execute the right work to optimize unit reliability	Excellence in maintenance, outage, and project execution	Be the generator of choice
Key Focus Areas				
• Promote simple and clear safety messages that resonate with our workforce and vendor partners • Champion continuous improvement of Work Protection performance and culture of corrective actions • Strengthen Safe Work Planning, Pre-Job Briefs, and Tailboard best practices	• Build up agility to lead change to focus on modernization • Advance trust, respect, and inclusion through RG Culture Plans • Actively guide and support employees to achieve performance expectations	• Enhance Asset Management processes to drive consistency in asset planning and evaluation • Focus efforts to advance key areas of Equipment Reliability • Align on fleet-wide strategies for governors, bearings, and runners	• Optimize maintenance strategies and work management processes across the fleet to start data-centric decision making • Improve unit-over-unit performance through predictability and reliability in project planning and execution • Augment process for generation planning and outage planning	• Modernize work processes; integrating data, transitioning to data-centric operations, and standardizing plant configuration across the fleet • Expand training programs to meet tomorrow's needs • Future-proof our workforce through knowledge management and succession planning
Measure(s) of Success				
Vendor safety performance Work Protection Performance Index SIIR & TRIF	Modernization Change Management Plan Engagement Results Absenteeism data, 9-Box	Optimized Project Portfolio Reliability metrics Availability metric	Work Management Performance Index Project Milestone & Capital Spend / In-service & Gate 3 Release Schedule Outage Factor	Modernization Change Management Plan Training metrics MyPower metrics

***Right-click** on the table and select **Drill through** to view GDARs associated with a specific Objective*

SEC Interrogatory #153

Interrogatory

Reference:
F1-1-1, p. 17-36

Question(s):

With respect to hydroelectric key performance metrics:

a) Please update Charts 1,3,4,6,8,10 and 12 with actuals for 2025.

b) [p.25, Chart 8] Please explain the high Equivalent Forced Outage Rate of 14% for Pine Portage GS as shown in 2024.

c) [p.29] Please provide the targets for Regulated Hydroelectric Total Generation Cost ("TGC") Performance for 2025-2031. If targets are not developed, please explain why.

d) [p.29] Please explain why redevelopment projects are excluded from TGC.

Response

a) Refer to Chart 1.

Chart 1 – Key Performance Metrics (2025 Actuals)

Performance Metric	2025 Actuals
Total Recordable Injury Frequency	0.33
Environmental Performance Index (%)	100%
Total Recordable Environmental Events	4
Availability (%)	85.5%[1]
Equivalent Forced Outage Rate (%)	6.6%[2]
Unit Energy Cost ($/MWh)	$10.9/MWh[3]
Total Generating Cost ($/MWh)	$35.4/MWh[4]

b) The 14% Equivalent Forced Outage Rate shown in Ex. F1-1-1, Chart 8, for the year 2024, is attributable to a turbine bearing failure on Pine Portage GS G3.

c) Refer to Ex. L-F1-Staff-168.

d) Total Generating Cost ("TGC") is calculated in alignment with Electric Utility Cost Group methodology to facilitate peer-utility comparisons. Given the nature of redevelopment projects, including that they are not completed in the normal course of operations, tend to be larger and are infrequent, and due to the variability in timing of such work across utilities, redevelopment project costs are excluded from the TGC calculation to help ensure a more comparable analysis.

[1] Refer to Ex. L-F1-Staff-170, Attachment 1 for details related to Availability 2025 actuals.
[2] Refer to Ex. L-F1-Staff-170, Attachment 2 for details related to Equivalent Forced Outage Rate 2025 actuals.
[3] Refer to Ex. L-F1-AMPCO-097 for details related to Unit Energy Cost 2025 actuals.
[4] Refer to Ex. L-F1-AMPCO-098 for details related to Total Generating Cost 2025 actuals.

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

SEC Interrogatory #155

Interrogatory

Reference:
F1-2-2, p. 1

Question(s):

Please explain the derivation of the materiality threshold used to explain variances for the Hydroelectric OM&A (i.e. "10% or greater at the function level, subject to a minimum materiality limit of $1M").

Response

The threshold of 10% or greater used to explain variances in the Hydroelectric OM&A costs reflects OPG's filing requirements, with the $1M minimum limit applied to exclude small variances in dollar terms in the context of the Application. This approach is consistent with past OPG payment amounts proceedings and helps to manage the volume of already extensive pre-filed evidence.[1]

[1] For example, EB-2020-0290, Ex. F2-2-2, p. 1, lines 21-22.

Board Staff Interrogatory #160

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 25 Chart 8
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 29
Ref 3: EB-2020-0290 Exhibit A1 / Tab 3 / Schedule 2 Attachment 1 p. 1
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 Attachment 4
Ref 5: Exhibit A2 / Tab 1 / Schedule 1 Attachment 4

Preamble:

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

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

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

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

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

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

Question(s):

a) Please confirm the numbers of the reported hydroelectric performance metrics in the current application for the years 2018 and 2019. If confirmed, please explain the change in amounts between the EB-2020-0290 reporting and the EB-2025-0297 reporting for the metrics. If not confirmed, please revise the numbers reported in the current application.

b) Please confirm that the Hydroelectric Availability referenced in the Financial Summary at Reference 5 is the same metric as the Hydroelectric Availability referenced at Reference 4. If confirmed, please revise the values in Exhibit A2-1-1 and Exhibit A1-3-2. If not confirmed, please explain the difference in calculating the two metrics. If providing this explanation, please provide the formula for each metric.

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

Response

a) OPG acknowledges the discrepancy identified in Reference 2 (Ex. F1-1-1, Chart 12) with respect to Total Generating Cost. In the course of responding to this interrogatory, OPG identified that the 2018 value was reported erroneously and should have been stated as $23.40, which is consistent with the value presented in Reference 3 (EB-2020-0290, Ex. A1-3-2, Attachment 1).

OPG confirms Equivalent Forced Outage Rate ("EFOR") in 2019 for the regulated hydroelectric fleet, as reported in Reference 1 (Ex. F1-1-1, Chart 8) is 6.7%. OPG also confirms that Reference 3 (EB-2020-0290, Ex. A1-3-2, Attachment 1) reported the 2019 EFOR for the regulated hydroelectric fleet as 6.4%.

The difference between the 2019 EFOR value reported in Reference 1 (6.7%) and Reference 3 (6.4%) is attributable to the reclassification of an outage at Sir Adam Beck Pump Generating Station over the period of September 23, 2019 to January 25, 2020. Applying the impact of the reclassification to the Reference 3 calculation basis increases the reported EFOR from 6.4% to 6.7%, thereby reconciling with the value reported in Reference 1. The outage-type change arose from an entry error in the outage reporting source system that was subsequently corrected in January 2020; all reporting from that point reflected the corrected EFOR value.

b) Confirmed. The regulated hydroelectric Availability referenced in the Financial Summary at Reference 5 (Ex. A2-1-1, Attachment 4) is the same metric as the regulated hydroelectric Availability in Reference 4 (Ex. A1-3-2, Attachment 4). Availability for the regulated hydroelectric fleet in 2024 was 85.2%, not 85.8% as reported in Reference 5. As the 2024 and 2025 Annual Consolidated Financial Statements and Management's Discussion and Analysis have already been published, OPG is unable to correct the error.

Board Staff Interrogatory #161

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 28 Chart 10
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 30 Chart 12

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

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

Question(s):

a) Please explain the relationship between Unit Energy Cost and Total Generating Cost. Please confirm that Unit Energy Cost is a key driver to Total Generation Cost. If not confirmed, please explain.

b) Please outline the strategies OPG intends to implement to better align its cost effectiveness performance with Business Plan targets.

Response

a) Unit Energy Cost ("UEC") and Total Generating Cost ("TGC") are distinct financial metrics used to assess cost effectiveness and financial productivity.[1] While the two metrics share common drivers, including operations, maintenance, and administration ("OM&A") costs and generation, they are calculated differently. The UEC is not a key driver of TGC.

   UEC measures direct OM&A costs per unit of energy produced (MWh). The UEC calculation excludes capital costs, gross revenue charge, and any other OM&A costs. In calculating UEC, generation is based on actual net energy production, net of surplus baseload generation ("SBG") spill and is measured on an annual basis.

   For clarity, the generation denominator of the UEC is sensitive to drivers such as waterflow conditions and electricity demand, causing variances in performance relative to targets. An example of this occurred in 2021 when low water flows had a considerable impact on generation (refer to Ex. E1-1-1, Figure 1, and Ex. E1-1-2), and resulted in a higher reported UEC (refer to Ex. F1-1-1, Chart 10).

[1] UEC and TGC are defined in Ex. F1-1-1, Section 4.4.1 and 4.4.2, respectively.

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

TGC measures the total cost of operating the regulated hydroelectric facilities per unit of energy produced (MWh). The TGC calculation includes most OM&A costs, gross revenue charge, and sustaining capital. For the purposes of calculating TGC, generation adds back amounts spilled due to SBG. TGC is measured as a three-year rolling average, which helps to normalize fluctuations in generation and capital spend over time.

b) While the regulated hydroelectric business demonstrates strong cost performance – ranking in the first quintile for OM&A costs relative to a benchmark group of peer utilities (refer to Ex. F1-1-1, Section 5.3) – the Renewable Generation business unit ("RG") is planning a series of initiatives over the IR term to maintain performance and further improve results in line with business plan targets.

RG's continuous improvement goal is to enhance and optimize established work processes. Since 2023, these initiatives have been guided by the Excellence Plan framework, which supports sustained improvement across the People, Plant, and Future pillars. The Excellence Plan framework, described in Ex. L-F1-SEC-151, identifies RG's leadership and process improvements addressing safety, work management, preventive maintenance, equipment reliability, KPI focus, and discrete initiatives related to the environment and modernization.

Board Staff Interrogatory #163

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) Not confirmed. As discussed in Ex. F1-1-1, Section 4.2, Environmental Performance Index ("EPI") is a composite, weighted index as opposed to a sum. It includes the number of environmental spills, the number of regulatory infractions, and the implementation of other environmental initiatives. The Polychlorinated Biphenyl equipment removal program was the final environmental initiative being tracked through EPI; there were no other initiatives remaining in the composite metric.

   EPI's replacement in 2026 is Total Recordable Environmental Events ("TREE"). This metric provides a clearer view as to the exact number of regulatory and reportable impact of environmental infractions and spills (as opposed to being a composite metric).

Board Staff Interrogatory #164

Interrogatory

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

Preamble:

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

Question(s):

a) Please explain whether all overhaul project costs are expensed as OM&A (i.e. no capitalized costs), and whether the costs are included as base OM&A, project OM&A, or a combination both.

b) Please clarify whether refurbishment projects incur OM&A. If yes, please clarify whether the refurbishment-related OM&A is included as base OM&A, project OM&A, or both.

c) Please provide 2016-2027 actual and budgeted and/or planned overhaul project OM&A by year.

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

Response

a) All overhaul project costs are expensed as OM&A costs (i.e., not capitalized), in accordance with OPG's capitalization policy as described in Ex. D4-1-1. All such costs are expensed as Project OM&A costs.

b) As described in Ex. F1-1-1, Section 3.3, refurbishment projects may incur OM&A costs to remove existing assets. Removal costs include costs associated with dismantling, crating, tearing down, or disassembling equipment formerly in service. These costs are expensed to Project OM&A costs, in accordance with US GAAP (see Ex. D4-1-1, Section 2.0); there are no Base OM&A costs associated with this work.

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

c) The 2016-2027 actual and budgeted and/or planned overhaul Project OM&A costs by year (included in Ex. F1-3-1, Table 1, Line 4 and Line 9) are provided in Chart 1 below.

Chart 1 – 2016-2027 Actual and Budgeted and/or Planned Overhaul Project OM&A

Year	Overhaul Project OM&A ($M)
2016 Actual	14.4
2017 Actual	14.4
2018 Actual	12.5
2019 Actual	9.8
2020 Actual	17.0
2021 Actual	25.8
2022 Actual	28.3
2023 Actual	29.8
2024 Actual	27.3
2025 Actual	29.9
2026 Budget	36.0
2027 Plan	39.7

d) The 2016-2027 actual and budgeted and/or planned refurbishment Project OM&A costs by year (included in Ex. F1-3-1, Table 1, Line 5) are provided in Chart 2 below.

Chart 2 – 2016-2027 Actual and Budgeted and/or Planned Refurbishment Project OM&A

Year	Refurbishment Project OM&A ($M)
2016 Actual	0.1
2017 Actual	1.1
2018 Actual	0.0
2019 Actual	0.0
2020 Actual	2.9
2021 Actual	0.5
2022 Actual	1.1
2023 Actual	0.6

Year	Refurbishment Project OM&A ($M)
2024 Actual	2.6
2025 Actual	0.8
2026 Budget	9.9
2027 Plan	17.0

1

Board Staff Interrogatory #165

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) An Original Equipment Manufacturer ("OEM") performing work under a Renewable Generation Programmatic Collaboration Agreement assigns costs directly to the specific refurbishment project to which the work relates, whether the project is regulated or unregulated. The OEM does not incur common costs that need to be allocated across multiple refurbishment projects.

Board Staff Interrogatory #166

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) The lower forecasted availability is driven by the expected increase in planned station work in 2027-2031. Between 2027-2031, 65% of the forecast outage hours are associated with station project work (i.e., non-maintenance outages).

   For comparison, forecast outage hours associated with planned station project work were 57% in 2026 and 53% in 2025.

Board Staff Interrogatory #167

Interrogatory

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

Preamble:

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

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

Question(s):

a) Please explain whether the 2016-2024 missed targets are due to actual planned outage work being ahead of schedule, changes to the scope of planned outage work, or nether.

b) Please explain why there were higher than planned outage activities in 2016-2024.

Response

a) and b)

OPG interprets these questions to be in relation to the historical Equivalent Forced Outage Rate ("EFOR") discussed in References 1 and 2, and not the forecast period.

The missed EFOR targets for 2016-2024 were neither due to actual planned outage work being ahead of schedule nor changes to the scope of planned outage work. The targets were missed due to forced outages (Ex. F1-1-1, p. 26, lines 1-15).

The primary contributors to higher EFOR during this period were bearing failures, most notably at R.H. Saunders GS, and turbine reliability issues at the Sir Adam Beck complex and Lower Notch GS.

Board Staff Interrogatory #168

Interrogatory

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

Preamble:

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

Question(s):

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

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

Response

a) and b)

Consistent with historical practice, as explained in EB-2016-0152,[1] OPG does not set Total Generating Cost targets for the regulated hydroelectric business.

[1] OPG Reply Argument, EB-2016-0152, June 19, 2017, p. 220; Decision and Order, EB-2016-0152, December 28, 2017, pp. 148-149.

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

Board Staff Interrogatory #169

Interrogatory

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

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

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

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

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

Table 1 – OM&A and FTE increase comparison

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Base OM&A ($ millions) - Ref 1 table Line No. 1	204.52	205.42	215.47	236.47	251.16	264.26	274.16	286.22
Project OM&A ($ millions) - Ref 1 table Line No. 2	53.55	81.11	74.10	75.26	68.32	92.63	90.48	126.97
Subtotal	258.08	286.53	289.57	311.73	319.48	356.89	364.64	413.19
Year-Over-Year increase in OM&A		**11.02%**	1.06%	**7.65%**	2.49%	**11.71%**	2.17%	**13.31%**
Regulated Hydroelectric OM&A FTEs - Ref 3 table Line No. 6	899.2	882.4	905.5	931.8	978.6	1051.6	1075.0	1074.0
Year-Over-Year increase in OM&A FTEs	N/A	**-1.87%**	2.62%	**2.91%**	5.02%	**7.46%**	2.23%	**-0.09%**

Question(s):

a) Please provide FTE breakdowns into OM&A and Capital in 2016-2019 as shown in the table in Reference 2 above.

b) OEB staff notes the year-over-year increase in OM&A is much higher than the year-over-year increase in OM&A FTEs in 2021, 2023, 2025 and 2027 (i.e. % bolded in Table 1). Please provide any non-compensation cost drivers that result in Base and Project OM&A increases in 2021, 2023, 2025 and 2027

Response

a) Refer to Chart 1 below.

Chart 1 – Regulated Hydroelectric FTEs Breakdown 2016-2019

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Regulated Hydroelectric Capital:				
Regular Staff	43.3	59.9	78.5	109.4
Non-Regular Staff:				
Temporary	0.8	2.1	3.8	5.1
Total Regulated Hydroelectric Capital	**44.1**	**62.0**	**82.4**	**114.4**
Regulated Hydroelectric OM&A:				
Regular Staff	936.9	903.8	947.6	915.2
Non-Regular Staff:				
Temporary	34.4	42.1	48.6	43.5
Total Regulated Hydroelectric OM&A	**971.3**	**945.9**	**996.3**	**958.7**
Total Regulated Hydroelectric	**1,015.4**	**1,008.0**	**1,078.6**	**1,073.1**

b) The main drivers of the referenced non-compensation increases in Base and Project OM&A costs in 2021, 2023, 2025, and 2027 are identified below. Additionally, OPG notes that compensation OM&A costs, while not the primary driver of these variances, are impacted year over year by wage escalation, in addition to the number of FTEs.

2021 (Actual)

The main driver of higher non-compensation costs in 2021, compared to 2020, is Project OM&A in Western and Eastern Region portfolios:

- Western Region: A provision of $9.5M in connection with a Final Settlement Agreement with a First Nation to perform remediation work to address shoreline erosion impacts (refer to Ex. F1-3-2, p.4, lines 6-12 and Ex. F1-3-1, Table 1, Note 2).
- Eastern Region: Purchased services in the OM&A Project portfolio increased primarily due to turbine-generator overhaul work ($10M).

2023 (Actual)

The main driver of non-compensation costs in 2023, compared to 2022, is an increase in Base OM&A purchased services related to maintenance costs, primarily at R.H. Saunders GS, Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (refer to Ex. F1-2-2, p.4, lines 1-4).

2025 (Budget)

The main driver of higher non-compensation costs in 2025, compared to 2024, is an increase in Project OM&A costs for Infrastructure expenditures consisting of removal costs associated with capital work (Ex. F1-3-1, p. 4, Section 3.3 and Table 1).

2027 (Plan)

The main driver of higher non-compensation costs in 2027, compared to 2026, is Project OM&A purchased services in Eastern and Niagara Regions, and removal costs (refer to Ex. F1-3-2, Section 2.1):

- Eastern Region: Increased expenditures related to concrete repair and restoration projects, primarily pertaining to concrete structures at Des Joachims GS and R.H. Saunders GS.
- Niagara Region: Increased expenditures for Niagara station overhaul projects, such as DeCew Falls 1 GS. Additional contributors include building rehabilitation programs.
- Infrastructure costs: Increase in planned removal costs associated with capital work (Ex. F1-3-1, p. 4, Section 3.3 and Table 1).

The percentage increase in the labour costs is higher than the percentage increase in FTEs, primarily due to cumulative wage escalation assumptions between 2027 and 2031 (refer to Ex. L-F4-Staff-227).

On average, labour costs account for an average of 78% of total Base OM&A over the 2016-2027 period. While labour rates have escalated annually (as described in Ex. L-F4-Staff-227), the primary driver for the discrepancy between the year-over-year increase in OM&A versus the year-over-year increase in OM&A FTEs is non-compensation costs.

Board Staff Interrogatory #172

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) The actual 2025 regulated hydroelectric regular and non-regular FTEs are 1329.9. This represents a variance of -98.4 to the 2025 budget of 1428.3 FTEs.

   Although actual FTEs were under budget in 2025, increased hiring occurred in the last four months of the year in Renewable Generation Operations and Support functions, such as Engineering. If such headcount increases were annualized and normalized to a full-year basis, the 2025 FTE variance would be reduced by approximately 45 regular FTEs. Additional hiring has continued into 2026 to ensure Renewable Generation is appropriately positioned to execute the planned project portfolio.

Board Staff Interrogatory #173

Interrogatory

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

Preamble:

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

Question(s):

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

Response

a) Chart 1 provides the requested breakdown of the compensation-related year-over-year change in Regulated Hydroelectric Base OM&A costs over the 2022-2027 period.

Chart 1: Compensation Related Hydroelectric Base OM&A Year-over-Year Changes

($millions)	**2023**	**2024**	**2025**	**2026**	**2027**
Collective Agreement Wage Escalation (1)	1.3	2.5	4.8	4.7	4.4
Collective Agreement Signing Bonus- PWU (2)	3.1	(3.1)	-	-	-
Retrospective Wage Adjustments- Bill 124 Moderation Period Settlement (PWU & Society) (3)	10.1	(0.3)	(9.8)	-	-
FTE Changes- (PWU & Society)	2.8	9.4	11.7	2.7	0.3
Non-Wage Related Pension/OPEB Cost & Other Changes (4)	(2.3)	3.2	7.5	5.7	2.8
Total year-over-year change	**15.1**	**11.7**	**14.2**	**13.1**	**7.5**

(1) Wage escalation impact on wage dependent compensation component costs.
(2) Refer to Ex. L-F4-SEC-194.
(3) Represents retrospective wage adjustments for the Bill 124 moderation period settlement (refer Ex. F4-3-1, Section 6.2.1 and Ex. L-F4-SEC-194).
(4) Includes non-wage dependent components such as statutory benefits, pension and OPEB (refer to Ex. F4-3-2, p. 20, line 1 to p. 22, line 8), as well as management compensation costs.

Witness Panel: Compensation and Corporate Costs

Board Staff Interrogatory #174

Interrogatory

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

Preamble:

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

Question(s):

a) Please clarify if overhaul projects are considered a stand-alone project with separate OM&A cost tracking, or if they form a part of the turbine-generator refurbishment project. Please confirm that costs will be assessed (i.e. capitalized or expensed) according to OPG's capitalization policy.

b) Given the significant term-over-term increase in project OM&A, please confirm that, in 2013-2026, OPG did not change its methodology for classifying overhaul project costs as OM&A.

c) Please provide an approximate breakdown of the $46.8 million increase, showing the amount attributable to market/inflationary-related increases and the amount attributable to an increase in the number of projects in the OM&A portfolio.

Response

a) Overhaul projects are stand-alone projects with separate OM&A cost tracking; they may be executed concurrently with refurbishment projects. OPG confirms that these costs are assessed in accordance with OPG's capitalization policy, in line with US GAAP (refer to Ex. L-F1-Staff-164 for further details).

b) Confirmed.

c) The portion of the referenced term-over-term increase in Project OM&A costs attributable to market/inflationary-related impacts cannot be specifically isolated, as Project OM&A costs are inherently affected by both the variability in scope and composition of project work and the market-driven cost escalation affecting individual project costs. Refer to Ex. L-F1-Staff-177 for further discussion.

OPG notes that, while there has been a nominal increase in the annual number of OM&A projects with actual or planned spend between 2022-2027, the increase in the 2022-2026 annual average spend compared to the 2027 test period is primarily due to the scope and timing of Project OM&A work being executed.

For additional context, OPG provides a breakdown and relative increase of the key categories of Project OM&A spend for the 2022-2026 annual average and 2027 test year, in Chart 1 below. Term-over-term variance explanations are provided in Ex. F1-3-2, pp. 3-4, which include an increase in portfolio projects and higher infrastructure costs from removal work tied to capital refurbishment projects.

Chart 1 – Regulated Hydroelectric OM&A Project Spend (2027 vs. 2022–2026 Average)

Portfolio Composition	2022-2026 Average OM&A Project Spend ($M)	2027 OM&A Project Spend ($M)	Increase ($M)	Reference
Infrastructure	16.8	32.7	15.9	Ex. F1-3-2, Section 2.2
Other Portfolio Projects	17.8	29.2	11.4	Ex. F1-3-2, Section 2.1
Concrete	13.9	25.3	11.4	Ex. F1-3-2, Section 2.1
Turbine-Generator Overhaul	31.7	39.7	8.0	Ex. F1-3-2, Section 2.1
Total	**80.2**	**127.0**	**46.8**	

Board Staff Interrogatory #175

Interrogatory

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

Preamble:

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

Question(s):

a) Given there are 30 concrete restoration initiatives in the 2027 test year, please clarify whether the Alkali-Aggregate Reaction concrete mitigation costs are all treated as project OM&A or if they also appear elsewhere in the OM&A and capital budgets.

b) Please provide the Alkali-Aggregate Reaction concrete mitigation-related OM&A expenditures in 2022-2025 (actual) and 2026-2027 (budget and plan), by year.

Response

a) Costs associated with Alkali Aggregate Reaction ("AAR") concrete work may be classified as Base OM&A costs, Project OM&A cost, or capital costs, depending on the specific scope or nature of the work, in accordance with OPG's capitalization policy (see Ex. D4-1-1). Accordingly, AAR-related mitigation costs are not necessarily all treated as Project OM&A costs, and may also appear elsewhere within OM&A and/or capital budgets, as applicable.

b) Routine inspections and minor repairs of concrete are both expensed to Base OM&A costs. These costs can include both regular concrete repairs and those related to AAR mitigation. Base OM&A expenditures directly related to AAR mitigation cannot be isolated from other concrete expenditures. As such, OPG is unable to provide AAR mitigation-related Base OM&A expenditures by year for 2022-2025 (actual) and 2026-2027 (budget/plan) as they are not tracked in a manner that enables discrete identification from other concrete OM&A costs.

Project OM&A costs for work directly related to AAR concrete mitigation are provided in Chart 1 below.

Chart 1: Project OM&A Costs for Alkali Aggregate Reaction Mitigation

2022 Actual ($M)	2023 Actual ($M)	2024 Actual ($M)	2025 Actual ($M)	2026 Budget ($M)	2027 Plan ($M)
6.9	4.3	2.1	0.5	6.5	4.9

Board Staff Interrogatory #176

Interrogatory

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

Preamble:

At Reference 1, OPG states that it holds a lease agreement with the St. Lawrence Seaway Management Corporation. The current 30-year lease is in place until 2038, with rates subject to review every five years. The water conveyance payment terms are currently in legal arbitration.

Question(s):

a) Please clarify when the existing rates expire and provide an update on the rates review.

Response

a) The existing rates expired on June 30, 2023. OPG anticipates the rate review, including the arbitration, to be completed by approximately Q4 2026.

Board Staff Interrogatory #321

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / pp. 21-27

Preamble:

Exhibit F1, Section 4.3 Reliability, presents the station-specific Availability / EFOR charts and supporting narrative for DeCew Falls 2 GS, Abitibi Canyon GS, Otter Rapids GS, Otto Holden GS, R.H. Saunders GS, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and the historical Western Region forced-outage discussion for Manitou Falls GS.

Question(s):

a) For the referenced major hydro projects at charted or otherwise reliability-significant facilities, please provide a consolidated facility-by-facility explanation of how OPG determined each project's expected contribution to forecast Availability, reliability, and EFOR under Exhibit F1, Section 4.3. In particular:
   i. For each project, identify whether the principal expected benefit is Availability-side, EFOR-side, or primarily enabling/supporting in nature.
   ii. Identify whether each project's benefit is already embedded in the pre-2025 baseline or is assumed to contribute planned outage burden and/or post-project benefit during the 2025–2031 forecast period.
   iii. Identify the specific failure modes, operating restrictions, hydraulic/control limitations, electrical limitations, or structural/civil conditions being addressed.
   iv. For each charted facility, explain how the project sequencing and expected in-service timing were reflected in the station's forecast Availability and EFOR targets.
   v. Identify what residual reliability risk remains at each facility if the project is delayed, re-scoped, or not completed as planned.
   vi. Explain how OPG distinguished between direct unit-refurbishment projects and indirect enabling/support projects, and how OPG avoided double counting reliability benefits where multiple projects support the same facility.

Response

a)
   i. The turbine-generator overhaul and refurbishment projects are necessary to address the asset condition of an aging fleet; without these investments, asset reliability is expected to decline (refer to Ex. F1-1-1, Section 3.2.1, p. 4).

For the eight stations referenced in the preamble, OPG is forecasting to in-service 21 refurbished units (~1/3 of the units at these eight stations) during the IR period. The principal expected benefit is station availability, which is expected to improve once all the planned unit overhaul and refurbishment activities at the station are complete. For a full description of the methodology to calculate Availability and EFOR, refer to Ex. L-F1-Staff-170.

ii. All outages associated with projects at the eight stations referenced in the preamble are included in the 2025-2031 reliability targets.

iii. OPG interprets “major hydro projects” to mean Tier 1 capital projects. Details on the specific failure modes, operating restrictions, hydraulic/control limitations, electrical limitations, or structural/civil conditions being addressed for these projects are provided in each project’s Business Case Summary.

iv. As described in parts i) and ii) above, the target-setting methodology considers the sequencing of planned outages, which as noted reflect the planned projects, as described in Ex. F1-1-1, p. 22. The estimates for planned outage hours during any year are based on the planned outage schedule, which is used to determine the forecast Availability. OPG continues to optimize the timing and duration of its outages where possible, but as noted these are subject to a number of factors (as described in Ex. E1-1-1, Section 4.0) which could necessitate a change in the timing of planned outages.

v. Risks associated with delaying or not completing the referenced projects are identified in each project’s Business Case Summary.

vi. Forecast targets are not set using project-specific reliability benefits, thus multiple projects being worked on concurrently at the same facility would not result in any double-counting.

VECC Interrogatory #011

Interrogatory

Reference:
Exhibit F1, Tab 4, Schedule 2, Table 1

Question(s):

a) Please provide the letter of June 11, 2024 referred to in note 2 of Table 1 – Gross Revenue Charge – Regulated Hydroelectric.

b) Please update Table 1 to show 2025 actual costs.

Response

a) Refer to Attachment 1, previously filed in EB-2024-0136.

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

Evelyn Wong
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BY RESS

June 11, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms. Marconi:

Re: EB-2024-0136 – Stakeholder Consultation on the Review of OPG Filing Guidelines

Ontario Power Generation Inc. ("OPG") appreciates the opportunity to provide comments on the Ontario Energy Board's ("OEB") proposed update to OPG's filing guidelines (now referred to as filing requirements) ("Filing Requirements"), which outline filing expectations for OPG's payment amount applications under section 78.1 of the *Ontario Energy Board Act*.

OPG agrees with OEB staff that the Filing Requirements are functioning reasonably well, and that updates should be targeted on incremental improvements.

OPG has organized its comments in the same structure as the Filing Requirements. Where OEB staff sought specific feedback, OPG has provided its comments in those particular sections. In conjunction with this letter, OPG is providing as Attachment 1 a detailed mark-up of all proposed changes to the draft Filing Requirements with annotations to explain each change. While this letter explains the more significant changes proposed, OPG respectfully requests that all the changes set out in Attachment 1 be considered, as a number of them are intended to clarify the requirements and to ensure continuity of information to be presented in future applications.

Section 1 Introduction and Overview of Legislative Context

OPG has no concerns with removing specific details in favour of keeping the Filing Requirements evergreen, as drafted by OEB staff. In the same spirit and as OPG believes that it should not be the purpose of the Filing Requirements to prescribe the length of a payment amounts term, OPG recommends removing the second sentence from footnote 1 of this section.

Section 2.5 Structure of Application

OPG's proposals for this section are mainly focused on clarifying the language referencing allocations of total corporate costs. Specifically, OPG has proposed to clarify that not all exhibits are affected by such allocations and where such allocations occur, they may be made directly to each of the nuclear and regulated hydroelectric categories, rather than as a two-step allocation to the prescribed facilities as a whole and then to each of the regulated categories.

Section 2.6 Key Planning Parameters

OPG's comments for this section are focused on the four areas set out below.

International Financial Reporting Standards

OPG does not have concerns with OEB staff's proposed requirement for OPG to provide information on its transition to International Financial Reporting Standards (from US generally accepted accounting principles), when this transition becomes applicable, including the associated references to the OEB's guidance in this regard.

Year-over-Year and Term-over-Term Analysis

OEB staff have proposed to replace the requirement for the detailed year-over-year variance analysis of operating costs with a requirement for a payment amounts term-over-term variance analysis, while retaining the year-over-year analysis for capital costs. Upon consideration of stakeholder session feedback and OPG's own evidentiary needs to support its application, OPG believes that year-over-year variance analysis of operating costs provides value and should be retained. In view of OEB staff's stated needs, OPG does not object to providing both a year-over-year and a term-over-term variance analysis for operating, maintenance and administration ("OM&A") costs (other than Project OM&A as described below).

On the other hand, OPG believes that year-over-year variance analysis has limited value for capital and Project OM&A. Project portfolios are optimized over multiple years and inherently reflect variability in the composition, nature and timing of projects, as well as the shifts that can occur between years of an individual project over its lifespan. Accordingly, it is OPG's view that term-over-term analysis for capital costs and Project OM&A costs is more meaningful in identifying material trends and drivers of variance. Therefore, OPG proposes that the Filing Requirements replace year-over-year variance analysis with term-over-term variance analysis for capital costs and Project OM&A costs.

Minimum Number of Historical Years and Next Hydroelectric Rebasing Application

With respect to the minimum filling requirements for historical years, OPG believes it is reasonable to limit the historic years to no more than five years as a general rule. OPG's view is that five years of historical actual data should be sufficient to determine any trends, that information going back more than five years likely has limited relevance due to the passage of time, and that requiring the filing of more than five years of historic information can result in excessive effort for OPG to maintain this information on a comparable basis (e.g., due to changes in organizational and cost structures over time). OPG believes it should have the flexibility to determine whether information going back more than five years is necessary to support approvals sought in an application, on a case-by-case basis. This is the basis for OPG's proposal to limit the minimum historical information requirement to five years in the Filing Requirements, on an evergreen basis.

In the current circumstance, however, OPG recognizes that its hydroelectric payment amounts have not been rebased since EB-2013-0321. Specifically, in EB-2016-0152, the OEB approved a price-cap index rate-making methodology for OPG's regulated hydroelectric business, with the payment amounts as approved in EB-2013-0321 used as the basis for the going in payment amounts for the 2017-2021 period. In EB-2020-0290, the OEB approved the hydroelectric payment amount for the 2022-2026 period that is equal to the 2021 payment amount, as required by O. Reg. 53/05. As a result, OPG has not filed historic actual information for its regulated hydroelectric business since 2013.

The draft Filing Requirements suggest that OPG would be required to file 12 years of historical and two years of bridge information for the hydroelectric business assuming the application is filed in 2025. However, OPG does not have the necessary data to normalize the 2013-2015 historical actual OM&A costs and compensation and benefits information for the hydroelectric business on a comparable basis with the rest of the application as a result of the number of organizational structure changes over the last decade. Historical hydroelectric OM&A costs and compensation and benefits data prior to 2016 would therefore have little to no value to the proceeding and could not be meaningfully integrated with the rest of the application.

In consideration of these unique circumstances and stakeholder session feedback, for its next hydroelectric rebasing application, OPG proposes to file the following in addition to the requirements for the five most recent historical years:

1. Hydroelectric rate base continuity tables (including gross plant and accumulated depreciation and amortization) and associated capital projects in-service listings back to 2013 on a total regulated hydroelectric basis only, rather than at a more granular level by geographical designation that OPG expects to use to present such information for the five most recent historical years (expected to be 2020-2024) as well as the bridge and forward-test years.[1]
2. For other applicable tables and information on compensation and benefits, four additional years of historic actual data on a total regulated hydroelectric basis only (expected to be 2016-2019). Where OPG is unable to file such information, it would explain why this is the case in the application.
3. Due to the age of the data, OPG may not be able to produce sufficiently detailed or meaningful variance analysis associated with the years beyond the five most recent historical years. In OPG's view, such analysis would also be of limited value given the passage of time. As such, for information filed beyond the five most recent historical years, OPG proposes not to be required to provide an analysis of year-over-year, term-over-term or OEB-approved variances in the application.

Attachment 1 includes the above proposals as footnote 3 in Section 2.6.

In OPG's view, its proposal is reasonable and sufficient to ascertain trends, which is the main purpose of including past data in a forward test-year rate application. Historical data beyond the nine years would not reflect the current operational needs and circumstances of OPG's hydroelectric business and, in any

[1] OPG's 54 regulated hydroelectric facilities are managed by geographical designations which have been reorganized multiple times over the last decade. OPG's proposal to file data beyond the five most recent historical years on a total regulated hydroelectric basis stems from the goal of reducing the significant manual effort and assumptions that would be required to normalize historical information to account for these reorganizations, including allocations of operational support group costs. Such normalizations would be needed to ensure a comparable set of data across the full time period that would be presented in the application (consisting of nine historical, two bridge and forward-test years). For clarity, OPG would still normalize the nine historical years for organizational structure changes other than changes in the geographical designations, for example, where functions have transferred between corporate costs and operations support costs. It would also provide a functional breakdown of the costs.

event, as discussed above, limitations on comparable data availability significantly limit the utility of such information. OPG believes its proposed approach will meet the objective of ensuring that its application presents appropriate and sufficient information on a consistent basis, while balancing the amount of the information provided with its relative value and effort to prepare.

Excel Tables

Generally, OPG does not have concerns with the proposed requirement to file MS Excel versions of all pre-filed data tables in the application. However, OPG notes that it filed more than 200 tables in its EB-2020-0290 application and will likely have more tables in future applications, including those necessitated by the expected hydroelectric payment amount rebasing. Given that the tables sometimes represent extracts from internal working files and include content that may be linked to various internal data sources, OPG requests that the Filing Requirements allow for the Excel versions to be filed within 7 calendar days after submission of OPG's pre-filed evidence.

Section 3 Exhibit A Administrative Documents and Application Overview

OEB staff have recommended the addition of a list of requirements to be included in OPG's Administration and Overview as well as Background Financial Information evidence to align with Chapter 2 of the Electricity Distribution Rate Applications. OPG generally accepts this list, with three clarifications.

The proposed Filing Requirements have added that OPG is to provide "a list of relevant company policies and regulations". In addition to this not appearing to be a component of the Electricity Distribution Rate Application filing requirements, OPG finds this language to be overly broad in scope. OPG currently files a summary exhibit explaining its legislative and regulatory framework, and proposes that reference to this exhibit be included instead.

With respect to "a statement identifying and describing any changes to methodologies as used in previous applications," consistent with the limitation as set out in the Natural Gas Filing Requirements for material impact on customers, OPG has included a clarification that it would do so for any material changes.

With respect to "a detailed reconciliation of the financial results shown in the AFS [Audited Financial Statements] with the regulatory financial results filed in the application, including a reconciliation of fixed assets" and the "identification of any deviations that are being proposed between the AFS and the regulatory financial results, including the identification of any prior OEB approvals for such deviations", OPG has proposed revised language to clarify based on its understanding of the intent, using language consistent with Section 3.1, and in light of the fact that the OEB does not necessarily approve such deviations but rather the revenue requirement methodologies.

Section 4 Exhibit B Rate Base

OPG proposes several minor edits in this section to better align the requirements with the historical presentation of OPG's evidence, including: removal of a reference to "accrued deferred earnings, and annual amortization of accrued deferred earnings", which do not apply to OPG; clarifications related to the basis of bridge year forecast information; and removal of a reference to a detailed breakdown of plant accounts in the rate base continuity tables, as such information is instead provided in OPG's evidence at a point in time as part of independent depreciation studies.

Section 5 Exhibit C Capitalization, Cost of Capital and Nuclear Liabilities

All of OPG's proposed edits to this section are for clarity, to align with OEB-approved methodologies or to remove obsolete language. The main changes are highlighted below.

Given the passage of time, OPG believes that references to valuation of OPG's assets are obsolete given that the OEB accepted the valuations of OPG's assets upon them entering OEB jurisdiction, based on the audited financial statements at the time as required by O. Reg. 53/05. In the unlikely event OPG were to propose a change in the valuation methodologies, a requirement to discuss changes would be captured by requirements related to changes in methodologies in Section 3.1. As a result, OPG has proposed several deletions in Section 5.1.

Under Section 5.4, OPG has proposed edits to more accurately describe the information presented in its applications in support of the revenue requirement impacts of the nuclear liabilities pursuant to the OEB-approved methodologies and to ensure comparability of information application over application.

Section 6 Exhibit D Capital Projects

OPG's comments in this section are focused on OEB staff's request for feedback on whether the capital project cost thresholds used to determine the information required to be filed remain appropriate given that they were established in 2011, as well as OPG's proposed adjustments to the variance thresholds. As this section has historically also applied to Project OM&A, OPG has included its proposed changes to Project OM&A requirements in this section. OPG's proposal with respect to term-over-term analysis of capital costs and Project OM&A costs is as discussed under Section 3.1.

OPG believes that the 2011 project thresholds are no longer appropriate and should be adjusted to reflect inflationary increases over the 13 years since they were established. As further discussed below, OPG also believes that the necessary adjustments need not be the same as between capital and OM&A projects, recognizing the inherent differences in the work under each portfolio. To enhance regulatory efficiency in an application the size of OPG's, OPG proposes to increase the thresholds as follows:

Capital Projects	Project OM&A
• Tier 1: $40 million or more • Tier 2: Between $10 million and $40 million • Tier 3: Less than $10 million	• Tier 1: $30 million or more • Tier 2: Between $10 million and $30 million • Tier 3: Less than $10 million

For capital projects, OPG derived the proposed Tier 1 threshold by escalating the $20 million threshold from 2011 to the present based on Building Construction Price Indexes.[2] For Project OM&A, OPG derived the Tier 1 threshold by escalating the $20 million threshold from 2011 to the present based on the Consumer Price Index ("CPI"). For Project OM&A, OPG used CPI rather than the Building Construction Price Indexes to approximate the proposed change as costs associated with Project OM&A are typically labour rather than for construction/installation of assets. The proposed corresponding increases in the Tier 2 and 3 thresholds are similarly intended to recognize the escalation of costs due to the passage of time. OPG also observes that the Tier 3 threshold would be made consistent with the historical materiality threshold of $10 million used in OPG's applications generally.

In making this proposal, OPG notes that for nuclear projects alone, the existing thresholds resulted in the filing of 84 capital and project OM&A business cases in the EB-2020-0290 application. This number would

[2] Statistics Canada. (2024). Building Construction Price Indexes (Table 18-10-0276-01).

likely be significantly higher in the upcoming application given that hydroelectric business cases will be included and the general effects of inflation. As each business case requires an extensive review for confidential information prior to filing, limiting the increase in the number of business cases filed with each application would be consistent with the OEB's comments in Section 2.3 of the Filing Requirements.

OPG believes that the proposed thresholds are appropriate as they maintain the status quo of materiality considered in 2011, and would help to enhance regulatory efficiency and manage resourcing requirements for OPG, OEB staff and intervenors by focusing on the more material projects. OPG notes that while the revision in the thresholds would affect the filing of business cases, it would not reduce the level of summary information provided in OPG's tables for projects over $10 million.

OPG also believes that there should be adjustments to the variance analysis thresholds for Tier 1 capital projects and OM&A projects. OPG proposes that written explanation of variances be required where the variance is 20% or more of the project budget, which would be a change from the current 10% threshold. OPG makes this proposal for several reasons. First, for execution business cases, which are intended to align with the Association for the Advancement of Cost Engineering (AACE) Class 3 range of estimate, a project estimate is expected to be within an accuracy range of -20/+30%. The ranges are broader for earlier classes of estimates. Therefore, projects with a 20% variance are still reasonably within the range of expected project outcomes. Second, variance analysis for projects with a 20% or greater variance is more consistent with OPG's governance for variance analysis (also at 20%), at which point a superseding business case is required.

Section 8 Exhibit F Operating Costs

OPG's comments for this section are focused on the areas set out below.

Operating, Maintenance & Administration Costs

OPG's main comments in this section pertain to aligning requirements for the breakdown of OM&A costs with historical presentation in OPG's applications, as well as the appropriate threshold for provision of detailed information for purchased services or products expenses. OPG's feedback with respect to OEB staff's proposal for term-over-term analysis of OM&A costs is as discussed under Section 3.1.

The Filing Requirements generically refer to OM&A statements providing a breakdown of OM&A cost items on a work basis using a quantitative threshold. As discussed at the stakeholder session, in practice, OPG's application has consistently presented OM&A cost information using separate OM&A statements for each of Base, Outage and Project OM&A, with a further breakdown by major function, division or other categories, as applicable. For continued comparability in future applications, OPG has proposed amendments to the language to reflect the manner in which its applications have historically been structured.

With respect to the threshold for detailed information for purchased services and products, and consistent with the rationale for the Project OM&A thresholds set out above under Section 6, OPG proposes to modify and increase the threshold from "the lesser of 1% of total expenses before taxes or $20 million", to $30 million. The removal of the 1% reference simplifies the rule and makes it more comparable application over application. As discussed in Section 6, OPG believes that this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and would help to enhance regulatory efficiency and manage resourcing requirements for OPG, the OEB staff and intervenors by focusing on the more material items.

Depreciation, Corporate Cost Allocation and Taxes

OPG proposes several minor edits in this section to better align the requirements with other Sections and the historical presentation of OPG's evidence, including: clarification to align proposed language around the categories of assets between the rate base continuity tables in Section 4 and depreciation expense in Section 8.3; clarification that corporate costs are allocated to each of nuclear and regulated hydroelectric categories rather than first to the prescribed facilities as a whole in alignment with the proposed edits in Section 2.5; and clarification that income tax calculations are reconciled from regulatory income rather than financial accounting income.

Section 9 Exhibit G Operating Revenue (to be renamed to Other Revenue)

OEB staff observed that OPG's evidence in in this section was organized differently in EB-2020-0290 than in the Filing Requirements. OPG notes that these differences have existed since OPG's first OEB application. As discussed at the stakeholder session, parties agreed that the current evidence structure for this section as reflected in OPG's applications is appropriate, and that it would facilitate comparability application over application to revise the Filing Requirements accordingly. OPG has proposed edits to incorporate this view.

OEB staff also sought feedback on whether year-over-year or term-over-term variance analysis is needed for other revenues. For the same reasons as set out under Section 2.6 for operating costs, OPG believes that year-over-year analysis would be more meaningful. OPG also does not believes that term-over-term analysis is needed in this area.

Section 10 Exhibit H Deferral and Variance Accounts

OEB staff sought feedback on the removal of the list of deferral and variance accounts ("DVA") in keeping the Filing Requirement evergreen. OPG supports this change.

OPG has also proposed to clarify that DVA schedules should be provided only for historical years since the DVA balances are last cleared, in alignment with the practice in OPG's prior applications and the expectation that DVAs are to be cleared on the basis of actual, rather than forecasted, balances. Additionally, OPG proposes to remove the reference to proposals regarding the Nuclear Liability Deferral Account interest rate, as this matter has already been resolved in prior OPG applications.

Should there be any questions regarding these submissions, please do not hesitate to contact me.

Respectfully submitted,

Evelyn Wong

cc: Saba Zadeh, OPG
Aimee Collier, OPG
Charles Keizer, Torys LLP

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

Ontario Energy Board

Filing Requirements for Ontario Power Generation Inc.

Setting Payment Amounts for Prescribed Generation Facilities under Section 78.1 of the *Ontario Energy Board Act, 1998*

MMM DD, 2024

Commented [A1]: Note for stakeholders: The title is proposed to change from Filing Guidelines to Filing Requirements in order to harmonize this document with current practices (i.e., Transmission and Distribution Filing Requirements).

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FILING REQUIREMENTS FOR ONTARIO POWER GENERATION

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1. Introduction

This document sets out specific Filing Requirements for purposes of the setting of payment amounts for certain of Ontario Power Generation Inc.'s (OPG's) generation facilities under section 78.1 of the *Ontario Energy Board Act, 1998* (the Act).[1] The generation facilities in question are identified in O. Reg. 53/05 (*Payments Under Section 78.1 of the Act*) and are collectively referred to herein as the "prescribed generation facilities".

1.1 Overview of Legislative Context

Section 78.1 of the Act authorizes the OEB to set payments to be made to OPG with respect to the output of the prescribed generation facilities. Under O. Reg. 53/05, the OEB's authority in that regard commenced on April 1, 2008.

In addition to identifying the prescribed generation facilities, O. Reg. 53/05 generally empowers the OEB to establish the form, methodology, assumptions and calculations to be used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. It also contains rules that must be followed by the OEB in setting those payment amounts.

O. Reg. 53/05 requires that OPG establish certain deferral and variance accounts and that the OEB ensure recovery of the balance in those accounts subject to certain conditions being met; it also requires that the OEB ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG.

Commented [A3]: From the perspective of keeping the filing requirements evergreen, the second sentence in the footnote is unnecessary. The second sentence seemingly sets a firm requirement for a CIR application to be five years, whereas setting a payment amounts term is beyond the scope of the Filing Requirements.

Commented [A4]: Note for stakeholders: The list of generation facilities have been removed with the intention of keeping the Filing Requirements evergreen.

Commented [A5R4]: OK

[1] The working assumption reflected in these Filing Requirements is that OPG will be filing a payment amounts application every five years. ~~If the application is filed under the Custom Incentive Rate-Setting framework, the application is to include a minimum of five years of information for the prospective payment amounts term.~~

2. General Requirements

2.1 Introduction

In addition to the Handbook for Utility Rate Applications, which outlines the key principles and expectations of the OEB when reviewing an application, these Filing Requirements outline relevant information that is necessary for a complete payment amounts application. These Filing Requirements provide the minimum information that OPG must file for a complete payment amounts application. However, OPG should provide any additional information that is necessary to justify the approvals being sought in the application. If circumstances warrant, the OEB may require OPG to file evidence in addition to what is identified in these Filing Requirements.

A clearly written, accurate and complete application that presents information and data consistently across all exhibits, and clearly demonstrates the appropriateness of the relief sought (e.g., approval or permission) is essential for an effective regulatory review and timely decision making. The OEB's examination of an application and its subsequent decision are based on the evidence filed in that case. A complete and accurate evidentiary record is essential to facilitate an efficient regulatory process and a timely decision.

The material presented is OPG's evidence and the onus is on OPG to prove the need for and the basis for the proposed new payment amounts. The supporting information provided by OPG in its prefiled evidence should be scaled to the request that is being sought.

In determining what evidence to file, OPG should consider what reasonable information the OEB and the intervenors are likely to request and provide that information in the prefiled evidence rather than waiting for the request to be made at the hearing. The evidence should be designed to increase the understanding of the parties with the overall objective of reducing the number and scope of interrogatories required. This will ensure a better use of hearing time, and, if required, a more focused and informed cross examination on such evidence.

To the extent that materials are the same or substantially the same as those filed in previous payment amounts applications, OPG should indicate this to improve the efficiency of the review.

2.2 Completeness Review

The filing of a comprehensive application is essential for the development of an

Commented [A6]: Note for stakeholders: Sections 2.1-2.4 have been revised to align with other OEB filing requirements / handbook (Distribution, Transmission, Natural Gas).

Commented [A7R6]: OK

Commented [A8]: "likely to request" captures a broad assortment of potential documentation. OPG believes it is important to limit the requirement to reasonable requests.

accurate Notice of Hearing and for the timely and effective review of an application. Therefore, before the OEB can begin processing the application, it must conduct a preliminary review to determine if the application is complete. The preliminary review determines if the information provided adheres to these Filing Requirements and provides sufficient information to prepare an accurate Notice of Hearing, and if there is any missing information. According to the OEB's performance standards, the OEB has 14 calendar days to complete this preliminary review.

A filing that includes all documentation detailed in these Filing Requirements will be considered complete for purposes of further processing by the OEB. If the Registrar determines that the application is consistent with these Filing Requirements, the Registrar will issue a letter notifying OPG that the OEB has commenced processing the application.

If there are any information gaps in the application, OEB staff will contact OPG and provide OPG with an opportunity to file the missing information. The timing required for filing the missing information is determined by the type of information that is missing.

If the missing information adversely affects the OEB's ability to prepare the Notice of Hearing or materially affects the OEB's ability to assess the application, OPG will be required to file the missing information within the 14-day preliminary review period. If the information cannot be filed within the 14-day review period, the Registrar will issue an "incomplete letter." This letter will list the information that must be provided before the OEB can commence processing the application.

If the missing information does not adversely affect the OEB's ability to prepare the Notice of Hearing or materially affect the OEB's ability to assess the application, the OEB may commence the proceeding before the missing information is filed. In such applications, the Registrar will generally issue a letter directing OPG to file the missing information by the date of the OEB's first procedural order (refer to OEB performance standards for details on the timing of the first procedural order), so that the information is available for the preparation of interrogatories by OEB staff and intervenors. If the information cannot be filed by the noted date and the delay could impact the schedule for the case or the OEB's ability to continue processing the application, the OEB may stop the proceeding and place the application in abeyance until the missing information is filed.

The OEB also conducts an error checking process on a best-efforts basis. If any of the errors affect the OEB's ability to prepare the Notice of Hearing, the OEB expects these will be addressed within the preliminary review period. If the errors do not affect the preparation of the Notice of Hearing, the OEB expects any errors to be addressed before the issuance of Procedural Order No.1.

2.3 Confidential Information

The OEB relies on complete disclosure of all relevant material to ensure that its decisions are well-informed. To ensure a transparent and accessible rate review process, OPG should make every effort to file all material publicly and completely. However, the OEB's Rules of Practice and Procedure and the *Practice Direction on Confidential Filings* (the Practice Direction) allow OPG and other parties to request that certain evidence be treated as confidential. In the event a party is applying for confidentiality, the Practice Direction sets out the guidelines for filing a request for confidentiality and associated timelines.

OPG should be aware that the OEB is required to devote additional resources to the administration, management and adjudication of requests for confidentiality and confidential filings. OPG must ensure that filings for which they request confidential treatment are both relevant to the proceeding and genuinely in need of confidential treatment. A list of the categories of information that will presumptively be considered confidential is set out in Appendix B of the Practice Direction. To reduce the administrative issues associated with the management of those filings, the OEB expects that OPG will minimize, to the extent possible, requests for confidential information.

2.4 Certifications

If desired, the certifications listed in this section can be completed by a single individual within a single document, as long as the requirements set out below are met (i.e., the Chief Executive Officer, or Chief Financial Officer, or equivalent provide all certifications).

2.4.1 Certification Regarding Personal Information

All parties are reminded of the OEB's rules regarding personal information in any filing they make as part of a proceeding. Parties should consult Rule 9A of the OEB's *Rules of Practice and Procedure* (the Rules) (and the Practice Direction, as applicable) regarding how to file documents (including interrogatories) that have personal information in them.

Rule 9A of the OEB's Rules states that "any person filing a document that contains personal information, as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*, of another person who is not a party to the proceeding shall file two versions of the document." There must be one version of the document that is a redacted version of the document from which the personal information has been deleted or stricken, and a second version of the document that is un-redacted (i.e., that includes the personal information) and should be marked "Confidential—Personal Information".

The OEB does not expect that personal information would typically need to be filed. However, if OPG is of the opinion that it does need to file personal information as part of its application, the onus is on OPG to ensure that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction).

An application filed with the OEB must include a certification by a senior officer of OPG stating that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable).

OPG is required to provide a similar certification when filing interrogatory responses or other evidence as part of a proceeding.

2.4.2 Certificate of Evidence

An application filed with the OEB must include a certification by a senior officer of OPG that the evidence filed is accurate, consistent and complete to the best of their knowledge.

2.4.3 Certification of Deferral and Variance Account Balances

An application filed with the OEB must include a certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that OPG has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition.

2.5 Structure of Application

OPG's payment amounts application should contain the following nine exhibits:

Exhibit A Administrative Documents and Application Overview
Exhibit B Rate Base
Exhibit C Capitalization, Cost of Capital, and Nuclear Liabilities
Exhibit D Capital Projects
Exhibit E Production Forecast
Exhibit F Operating Costs
Exhibit G ~~Operating~~ Other Revenue
Exhibit H Deferral and Variance Accounts
Exhibit I Determination of Payment Amounts

Commented [A9]: Note for stakeholders: Exhibit titles have been revised based on experience from most recent proceedings.

Commented [A10R9]: OK

Commented [A11]: As discussed below in Section 9.

Each exhibit, where applicable, should provide the identified data for each category of prescribed generation facility (nuclear and hydroelectric). As applicable, ~~E~~each exhibit should also explain how allocations have been made from total corporate costs to each category of ~~the~~ prescribed generation facility (nuclear and hydroelectric) ~~is as a whole~~ and the non-prescribed generation facilities ~~as a whole~~. Where allocations are first made to the prescribed generation facilities as a whole, ~~Then from the allocation to the prescribed generation facilities,~~ an exhibit should explain how sub-allocations have been made to each of the nuclear and hydroelectric categories.

Commented [A12]: Not all exhibits are specific to data of a generation facility category.

Commented [A13]: The edits in the last two sentences are intended to clarify that 1) the concept of allocations does not apply to all exhibits, 2) in some instances allocations are made directly to each of the facility categories rather than as a two-step allocation to the prescribed facilities as a whole and then to each of the categories.

Excel spreadsheets should be provided as appropriate to the data in question with formulae indicating on-sheet calculations. As a minimum, OPG should file Excel spreadsheets summarizing the production forecast (as noted in section 7), compensation and benefits (as noted in section 8) and a Revenue Requirement Work Form (RRWF). The RRWF will be filed with the application including data and tables to support the payment amounts order for which OPG is seeking approval.

2.6 Key Planning Parameters

The key planning parameters listed below form the basis of how these Filing Requirements should be applied.

These Filing Requirements are based on a cost of service (single- or multi-) test year application. The OEB does not set out detailed requirements for Custom incentive rate-setting (IR) applications, which are by definition customized. However, these Filing Requirements should be used as a starting point for any Custom IR application by OPG, with additions and modifications as necessary. The filing should be made in accordance with United States Generally Accepted Accounting Principles (US GAAP) until OPG transitions to International Financial Reporting Standards (IFRS).

For IFRS transition guidance, when applicable, OPG should refer to the *Report of the Board: Transition to IFRS dated July 28, 2009* (IFRS Report), and subsequent amendments and addendum. While the IFRS Report was directed to electricity and gas distributors, the OEB will consider OPG's transition to IFRS in the context of the policies established in the IFRS Report as well as transitioning away from capitalizing indirect overheads.[2]

Commented [A14]: Note to stakeholders: A requirement to provide information on OPG's transition to IFRS as well as transitioning from capitalizing indirect overheads has been added.

Commented [A15R14]: OK, but propose a minor clarification that this is a requirement when OPG has plans to transition to IFRS.

In addition, OPG should meet the following requirements in preparing its filing:

- Data for the following years, at a minimum, must be provided:
  - Test Year(s) = prospective year(s)

[2] EB-2020-0200, Decision and Order, December 21, 2023, pp. 98-99.

- Bridge Year = current year (or the year immediately preceding the Test Year(s))
- Historic Years = Three most recent historical years (or for as many years as are necessary to provide actuals back to and including the most recent OEB-approved test year(s), but not less than three years, and not more than five years)[3]

- A summary of the main schedules should be presented on one sheet with multi-year data for the Historic Years, the Bridge Year and the Test Year(s)

- Where applicable, Aa detailed variance analysis should also be provided comparing OEB-approved to actual costs and production for each Historic Year and Bridge Year.[4] The phrase "OEB-approved" in these Filing Requirements refers to the set of data used by the OEB as the basis for approving the most recent payment amounts. This analysis should explain the drivers of the variance and the contribution of each towards the total ~~year-over-year~~ variance

- Cost variance analysis should include a comparison of the total costs for the most recent payment amounts term (i.e., the term sought for approval in the previous payment amounts application) with the total costs for the next payment amounts term (i.e., the term sought for approval in the current payment amounts application) to provide a term-over-term variance analysis. The term-over-term variance analysis should be provided for operating, maintenance and administration (OM&A) costs and capital costs~~all cost categories~~. The term-over-term analysis is not required for production data

- Written evidence should be presented before the data schedules

- With respect to any claimed revenue sufficiency/deficiency, OPG should provide a summary of the drivers of the sufficiency/deficiency for each Test Year, along with how much each driver contributes

[3] OPG's hydroelectric base payment amount has not been rebased since EB-2013-0321. For OPG's next application to rebase the hydroelectric base payment amount (expected to be filed in 2025), OPG is also to provide, going back to 2013, hydroelectric rate base continuity tables (including gross plant and accumulated depreciation and amortization) and associated capital projects in-service listings, on a total regulated hydroelectric basis only. For other applicable tables and information on compensation and benefits, OPG is to file a total of nine years of historical actual data (expected to be 2016-2024) for the hydroelectric business, where for the years beyond the five most recent historical years (expected to be 2016-2019), OPG is required to file such information on a total regulated hydroelectric basis only. Where OPG determines that it is unable to file any of this information beyond the five most recent historical years (expected to be 2020-2024), it will clearly set out the reasons as to why this is the case. For information filed beyond the five most recent historical years, OPG is not required to provide variance analysis.

[4] The requirement for year-over-year variance analysis is excluded for ~~operating, maintenance and administration~~capital costs. See section ~~8~~ 6 for more details.

Commented [A16]: OPG believes it is reasonable to limit the minimum filing requirements for historic years to five years as a general rule. OPG believes, in general, that five years of historical actual data is sufficient to determine any trends, that information going back beyond five years likely has limited relevance due to the passage of time and changes in the business, and that requiring the filing of any more than five years of historic information can result in significant effort to maintain this information on a comparable basis with Test Period information (due to potential for realignment of organizational/cost structures etc over time). OPG should have the flexibility to determine whether information of more than five years is necessary to justify its requests as part of the prefiled evidence, on a case-by-case basis.

Notwithstanding and without prejudice to this general position, with respect to the specific circumstances of the next hydroelectric rebasing application, OPG accepts the intervenors' interest in information spanning beyond the five years and, with certain limitations, generally proposes to file nine years of historical actuals as further set out in the footnote.

Commented [A17]: Re-inserted this language from the existing filing requirements to allow for alignment with the specific nature and requirements in each exhibit section. This will help keep the evidence comparable application over application.

Commented [A18]: Note to stakeholders: The requirement for a detailed variance analysis has been removed for OM&A costs. OEB staff have not found this information needed for its review of the payment amounts application.

Commented [A19R18]: OPG considered feedback from the stakeholder session as well as its own evidence needs. OPG believes that detailed year over year variance analysis for OM&A has value, whereas capital does not. OPG proposes to do detailed variance analysis, including year over year, for OM&A, and term over term for capital.

Commented [A20]: Minor clarification

Commented [A21]: Note to stakeholders: A requirement has been added to provide term-over-term analysis of costs. In past OPG payment amount applications, OEB staff conducted this analysis manually. This analysis was then verified by OPG through interrogatories. The addition of this requirement is intended to enhance regulatory efficiency.

Commented [A22R21]: OPG has no concerns with filing additional term-over-term variance analysis for OM&A and capital, which is where we believe term-over-term analysis would be meaningful. For other cost categories, OPG does not believe that this analysis would be helpful.

- Any documents are to be provided in bookmarked and text-searchable Adobe PDF format
- Within 7 calendar days of the application being filed, ~~Any~~ any tables must also be provided in a working Microsoft Excel spreadsheet format where available and practical~~.~~

Commented [A23]: OPG does not have concerns with filing excel versions of all tables in the application. However, OPG notes that it had more than 200 tables in its EB-2020-0290 application and will likely have more going forward. Given the existence of notes to draft and linkages to internal working files, OPG requests that the Filing Guidelines allow for the excel versions to be filed within 7 calendar days after submission of OPG's prefiled evidence.

3. Exhibit A Administrative Documents and Application Overview

The administrative documents identified in this section provide the background and summary to the filing. There are two sections:

1) Administration and Overview
2) Background Financial Information

The detailed requirements on what should be included for each section are shown below.

3.1 Administration and Overview

- Table of Contents / Exhibit List
- List of relevant statutory provisions (such as any provisions of, or regulations under, the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998*)
- ~~A list of relevant company policies and regulations~~Summary of OPG's legislative and regulatory framework
- A list of specific approvals requested and relevant section(s) of the legislation must be provided
- Summary of filing (purpose, need and timing of the filing)
- A primary contact for the application, who may be a person within the OPG other than the primary licence contact. The primary contact's name, address, phone number, and email address must all be provided. The OEB will communicate with this person during the course of the application. Identification of any legal or other representation for the application
- Confirmation of OPG's internet address for purposes of viewing the application and related documents, and any social media accounts (with addresses) used by OPG to communicate with its customers
- A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate
- A statement as to the form of hearing requested (i.e., written or oral) and an explanation for OPG's preference
- The requested effective date
- A list of OEB directions from any previous OEB Decisions and/or Orders, this includes any commitments made as part of an approved settlement. OPG must clearly indicate how these are being addressed in the current application
- A description of the organizational structure, showing the main units and executive and senior management positions within OPG
- A draft issues list – including preliminary prioritization of primary and secondary

Commented [A24]: Note to stakeholders: The items listed in this section have been revised to align with Chapter 2 of the Distribution Filing Requirements.

Commented [A25]: OPG finds this to be an overly broad scope, and this also does not appear to be a requirement for LDCs. OPG currently files a summary exhibit explaining its legislative and regulatory framework. OPG proposes to continue filing that exhibit, which it believes should address the objective here.

issues
- Procedural Orders/motions/correspondence
- Relevant maps (or provide link to webpage where maps can be found)
- List of witnesses and their curriculum vitae
- Budget directives and guidelines (capital and operating budgets), including economic assumptions used
- A schedule of overall revenue sufficiency/deficiency that include:
    - Numerical schedules detailing the drivers of the sufficiency/deficiency
    - Complete and detailed references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it
    - A detailed narrative of the causes of the sufficiency/deficiency highlighting the significant issues
- An overview of the allocation methodology for assets, costs and revenues to the prescribed and non-prescribed generation facility assets, and to the nuclear- and hydroelectric-specific businesses
- A statement identifying and describing any material changes to methodologies as used in previous application~~s~~
- A summary or copy of relevant orders from any federal or provincial agency (excluding OEB), Ministerial Directives and Shareholder Directives

Commented [A26]: Minor clarification - Adding a materiality consideration to this requirement given the size of the application, and noting that the comparisons should be application over application (i.e., as compared to the last application, and not an ongoing list of changes across all applications).

3.2 Background Financial Information

- Audited Financial Statements (AFS) approved by OPG's Board of Directors for each of the Historic Years (or provide the webpage address of the location on System for Electronic Document Analysis and Retrieval or Electronic Data Gathering, Analysis, and Retrieval where these audited financial statements can be found)
- AFS should be provided as soon as they are available. If the statements are not available at the time of filing, OPG should provide these as an update during the proceeding
- The most recent four quarterly OPG financial reports
- Rating agency reports for each of the Historic Years and the Bridge Year
- An overview of how the provisions of O. Reg. 53/05 is reflected in the filing compared to data in the AFSs
- A detailed reconciliation of the financial results shown in the AFS with the regulatory financial results filed in the application, including a reconciliation of the fixed assets and the identification of any material changes in the reconciling items used in the previous application. ~~This must include the identification of any deviations that are being proposed between the AFS and the regulatory financial results, including the identification of any prior OEB approvals for such deviations~~
- The most recent OPG Board of Directors-approved Business Plan for the regulated

Commented [A27]: OPG's proposed changes are to clarify the requirement based on our understanding of the intent, and to align with language in the list under section 3.1. For clarity, the OEB does not necessarily approve "deviations between AFS and the regulatory financial results" per se but rather approves OPG's revenue requirement and any underpinning methodologies, which may in turn be based on financial accounting values. The edits align to the presentation of information in OPG's past applications

components of OPG, including hydroelectric business, and the nuclear business. Any previous Business Plans that include part of a Test Year should also be filed.

4. Exhibit B Rate Base

A description of the prescribed generation facilities, and of any associated financial assets, should be provided. For nuclear rate base, a separate presentation of asset retirement costs associated with nuclear liability obligations is required.

Commented [A28]: Minor clarification.

Items used in the computations or derived should include opening and closing balances of the net fixed assets, working capital, accumulated depreciation~~,~~ and changes in working capital~~, accrued deferred earnings, and annual amortization of accrued deferred earnings~~.

Commented [A29]: These items do not apply to OPG.

The information presented here should cover three areas:

1) A list of gross assets (property, plant and equipment), including capital budgets and intangible assets (e.g., computer software) if any, included in rate base
2) Accumulated depreciation and amortization
3) Working capital including cash working capital calculation, fuel inventory (for the nuclear business), and materials and supplies

For each of these areas there will be some common statements that should be provided summarizing the rate base. The schedules for rate base should include the Historic Years, the Bridge Year ~~(actuals to date, balance of year as budgeted)~~ and the Test Year(s).

Commented [A30]: Full year budgeted information may be used for Bridge Year, depending on the circumstances

Additional statements that should be provided for 1 and 2 include:

Continuity statements

The continuity statements must provide year-end balances and annual activity, and include directly attributable costs, for example, capitalized borrowing costs.

Commented [A31]: Minor clarification

Summary variance explanation

A written explanation should be provided to identify the drivers to the variance for rate base. This applies to OPG's rate base for the following comparisons:

- OEB-approved vs. actual for each of the Historic Years
- OEB-approved vs. Bridge Year
- Year-over-year analysis over the Historic Years, the Bridge Year and the Test Year(s)

4.1 Gross Assets – Property, Plant and Equipment and Intangible Assets

Continuity statements should be provided as indicated above.

- ~~Required~~ statements and analysis should be broken down by major function or division
- ~~A detailed breakdown should be provided by major plant account for each functionalized plant item~~ for each of the Historic Years, the Bridge Year and the Test Year(s). For the Test Year(s), each plant item should be accompanied by a written description
- Mid-year averages should be provided

Commented [A32]: These edits align to the presentation of OPG's rate base evidence in past applications and to ensure continuity of such information to be presented in future applications. The indicated statements and analysis in this section are provided on a rolled up basis by several major categories in OPG's applications. Doing so by the detailed plant accounts comprising OPG's fixed asset would not be practical. A detailed breakdown of the plant accounts at a point in time is included as part of independent depreciation studies.

4.2 Accumulated Depreciation and Amortization

Continuity statements and a summary variance explanation should be provided as indicated above for each of the Historic Years, the Bridge Year and Test Year(s) by asset account. Continuity statements should be reconcilable to calculated depreciation costs.

4.3 Working Capital Calculation

A working capital calculation should be provided for the each of the Historic Years, the Bridge Year and the Test Year(s). The results should be provided on a single schedule for comparison. The basis for the calculation of cash working capital must be detailed.

5. Exhibit C Capitalization, Cost of Capital and Nuclear Liabilities

OPG should ensure that the total capitalization in the filing (debt, ~~and~~ equity and as applicable a provision for nuclear liabilities) equates to the total rate base.

Commented [A33]: These edits are to more accurately reflect the OEB approved methodology for capitalization of OPG's prescribed nuclear assets

5.1 Capital Structure – Amounts & Ratios

The following elements of the proposed capital structure should be detailed, with the necessary schedules, for each of the Historic Years, the Bridge Year and the Test Year(s):

- Long-term debt
- Short-term/unfunded debt (to equate total capitalization with rate base)
- Preference shares
- Common equity

Justification for the proposed capital structure is required, including an explanation of the following:

- Non-scheduled retirement of debt or preference shares and buy back of common shares
- Long-term debt, preference shares and common share offerings
- The assumptions and methodology used ~~since the establishment of the prescribed generation facility asset classes~~:

  ~~to develop prescribed generation facility asset valuations~~
  - to allocate OPG's debt to the prescribed generation facilities as a whole
  - to allocate OPG's debt as between the prescribed nuclear and hydroelectric generation facilities

Commented [A34]: This language appears to be obsolete. The OEB accepted the valuations of OPG's assets upon becoming rate regulated. If OPG were to propose any changes in valuation methodologies for rate-setting purposes, this would be captured by the OEB staff's new language in section 3.1.

- A historic accounting of changes to ~~OPG's~~ capital structure including:
  - Non-scheduled retirement of debt or preference shares or buy-back of common shares
  - Issuances of long-term debt, preference shares and common shares
- A discussion of material changes in the proposed capital structure (i.e., increased or decreased equity thickness) of OPG, and the reasons for these changes

Commented [A35]: The deemed capital structure is what is relevant rather than OPG's capital structure.

- All internal or commissioned reports, studies or analyses, from four years to the date

of filing, of ~~how to value OPG's assets and~~ how to allocate debt, by business unit or asset class

Commented [A36]: For clarity - same as above.

5.2 Component Costs of Debt

The following should be provided for each of the Historic Years, the Bridge Year and the Test Year(s):

- A calculation of the cost of each item
- A justification of forecast costs by item including key economic assumptions
- Profit or loss on redemption of debt
- Consensus Forecasts – latest interest rate forecast based on a selection of forecasters that are common to utilities (e.g., the major banks and the Bank of Canada)

5.3 Calculation of Return on Equity

Justification for the proposed return on equity is required, including the filing of supporting documentation, e.g., Global Insight reports.

5.4 Nuclear Waste Management and Decommissioning Costs

This section provides a summary of OPG's obligations for nuclear waste management and decommissioning. This exhibit should also provide the funding responsibilities as described in the Ontario Nuclear Funds Agreement.

Any updates or revisions to the Ontario Nuclear Funds Agreement Reference Plan must be summarized and the financial impacts explained in appropriate detail, including a reconciliation with the OEB-approved amounts for the Historic Years and the Bridge Year. If the reconciliation is summarized elsewhere in the application, the reference should be provided in this section.

Commented [A37]: **Note for stakeholders:** In efforts to keep the Filing Requirements evergreen, reference to specific years have been removed and are kept general.

Commented [A38R37]: OK

The information should be disaggregated to present Darlington and Pickering separate from Bruce.

The information presented should cover the following:

- The revenue requirement treatment and the revenue requirement impact of OPG's liabilities for decommissioning its nuclear stations and nuclear used fuel and low and intermediate level waste management
- The revenue requirement treatment and the revenue requirement impact of OPG's liabilities for decommissioning Bruce

Further, the exhibit should include:

- A summary of net book values of unamortized asset retirement costs for OPG's nuclear stations including Bruce~~, noting amounts of unamortized asset retirement cost,~~ for the Historic Years, the Bridge Year and the Test Year(s)
- Continuity statements providing year-end balances and annual activity for ~~A summary of the forecast pre-tax charge in OPG's income statement due to~~ the nuclear liabilities and the segregated funds

Commented [A39]: These edits are to more accurately describe the information presented in OPG's applications in support of the revenue requirement calculations pursuant to OEB approved methodologies, and to ensure comparability of information presented in future applications.

6. Exhibit D Capital Projects

This section provides details on OPG's capital project costs, including OPG's capitalization policy, accounting treatment of capital costs, capital expenditures and capital cost variance analysis. For clarity, this section will also apply to Project OM&A where relevant, namely, information required for Pproject OM&A and cost variance explanations.

Commented [A40]: This note was always in this exhibit following Table 1. Including it at the top for clarity.

6.1 Policies

OPG's capitalization policy and any changes to that policy should be presented as part of the capital budget evidence.

OPG should provide details on its proposed accounting treatment, including the treatment of costs of funds for capital projects that have a project life cycle greater than one year.

6.2 Capital Expenditures

OPG should provide a summary of capital expenditures for the Historic Years, the Bridge Year and the Test Year(s), including the OEB-approved amounts for the Historic Years and the Bridge Year.

The table below summarizes the information required based on capital project costs.

Table 1: Information Required in Capital Project Summaries

For Capital Projects of	Detail Required
$420 million or more	• Name, description, start date, in- service date, and cost for each project • Business case for each project • Provide actual in-service dates (month and year) for capital projects that closed to rate base in the Historical Years and provide projected in-service dates (month and year) for the Bridge Year and the Test Year(s) • Total cost of all projects in this category

Commented [A41]: **Note for stakeholders:** Seeking feedback on whether these capital project cost thresholds are still appropriate. The thresholds were set in 2011.

Commented [A42R41]: OPG believes that the project thresholds are no longer appropriate given the passage of time, but that the necessary escalations are not the same as between capital and OM&A projects.

Fror capital projects, based on Building Construction Price Indexes, $20 million in 2011 would be equivalent to approximately $40 million today. OPG believes these thresholds are appropriate as they maintain the status quo of materiality considered in 2011 and helps manage regulatory efficiency and better focus on material issues for both OPG and intervenors.

For project OM&A, based on Consumer Price Indices, $20 million in 2011 would be equivalent to approximately $30 million today (OPG used CPI rather than Building Construction Price Indexes to approximate this change as costs associated with Project OM&A are typically labour rather than the construction/installation of assets). OPG believes this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and helps manage regulatory efficiency and better focus on material issues for both OPG and intervenors.

Consistent with the above assessment, OPG has also proposed to increase the third tier to $10 million, while would also be made consistent with the historical materiality threshold of $10 million used in OPG's applications generally.

Between $~~5~~10 million and $~~4~~20 million	• Name, description, start date, in-service date, and cost for each project • Provide actual in-service dates (month and year) for capital projects that closed to rate base in the Historical Years and provide projected in service dates (month and year) for the Bridge Year and the Test Year(s) • Total cost of all projects in this category
Less than $~~5~~10 million	• Number of projects in this category, total cost of all projects in this category and average cost of the projects in this category • Provide the total cost related to projects that will close to rate base in the Test Year(s)

OPG should provide an overall summary table of the business cases filed. The summary table should include the title of the business case, date prepared, the project stage, and status of the business case (~~i.~~e.g., full, partial, developmental), for the current payment amounts proceeding. Where applicable, the table should also indicate the business case's status in the previous payment amounts proceeding. Note that all of the above is also applicable to Project ~~Operating, Maintenance and Administrative (~~OM&A~~)~~ business cases, except Tier 1 is greater than $30 million and Tier 2 ends at $30 million.

For capital projects with a project cost of $~~2~~40 million or more ($30 million or more for Project OM&A), OPG should provide a written explanation of variances where the variance is 20~~10~~% or more of the project budget.

Variance explanations should be provided for the following comparisons:

- OEB-approved vs. actual for each of the Historic Years
- OEB-approved vs. Bridge Year forecast
- ~~Year-over-year~~Term-over-Term analysis ~~over the Historic Years, the Bridge Year and the Test Year(s)~~

OPG should provide a summary table for capital projects and P~~p~~roject OM&A with a project cost of $~~5~~10 million and greater that were projected to go into service or to be completed during the previous payment amounts term. The table should include the project stage as provided in the previous payment amounts application and the current status of the project.

Commented [A43]: Minor clarification.

Commented [A44]: OPG believes that there should be adjustments to the variance analysis thresholds. For capital projects over $40 million and project OM&A over $30 million, OPG proposes to provide a written explanation of variance where the variance is 20% or more of the project budget. Firstly, for execution business cases within the Association for the Advancement of Cost Engineering (AACE) class 3 range of estimate, a project estimate is expected to be within an accuracy range of -20/+30%. The ranges are broader for earlier classes of estimate. Therefore, projects with a 20% variance are still within the range of expected project outcomes. Secondly, focusing the variance analysis on projects with a 20% variance is consistent with OPG's governance which requires a superseding business case at that variance threshold.

Commented [A45]: As noted above, OPG believes that year-over-year analysis of project variances is of limited value given the specific nature of each project and the inherent shifts between years of a project's lifespan that can occur. OPG proposes that term-over-term analysis would be more instructive in this instance.

Commented [A46]: Minor clarification.

7. Exhibit E Production Forecast

The production forecast and any normalization methodology should be provided. A description of outage planning processes and production reliability initiatives should also be provided.

The following information should also be included:

- Explanations of causes and assumptions for the production forecast
- Production for the Historic Years, the Bridge Year and the Test Year(s)
- Weather forecasting and hydrological forecasting methodologies
- All data tables used to determine the forecast should be presented in MS Excel spreadsheet format
- Comparison of historical data with the forecast data in regard to forecasting assumptions
- A variance analysis of production should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year analysis for the Historic Years, the Bridge Year and the Test Year(s)
- All significant economic assumptions and their sources used in the preparation of the production forecast should be included in this section
- Where ~~available~~applicable, actual and forecast generation losses due to spill should be filed

Commented [A47]: Minor clarification.

Commented [A48]: Minor clarification.

Commented [A49]: For clarity - Clarifying that this information is filed as necessary, e.g., to support clearance of the SBG Variance Account.

Hydroelectric Incentive Mechanism (HIM)

An analysis of the HIM should be provided. The analysis should include an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of any changes to the mechanism ~~that the OEB may have approved over time and/or any further changes~~ that OPG may wish to propose.

Commented [A50]: For clarity. The assessment of the HIM benefits captured in the first part of the sentence is necessarily inclusive of any changes to the mechanism previously approved by the OEB that are in effect. The edits are intended to make clear that there is no requirement to provide a separate assessment of each past change that may have been approved at any past point.

8. Exhibit F Operating Costs

8.1 Benchmarking Studies

This exhibit should include benchmarking studies that update studies filed in previous applications or new benchmarking studies. Further, this exhibit should include a consolidation of the benchmarking information so that comparisons are evident, e.g., Total Generating Cost, nuclear capacity factors, and other safety, reliability and value for money measures.

The benchmarking should note whether the basis is a forecast or actual results.

8.2 Operating, Maintenance & Administration Costs

For clarity, Project OM&A business cases and variance analysis should follow the requirements set out in Section 6 above.

Details of the budgets for each of the Historic Years, the Bridge Year and the Test Year(s) should be provided.

The OM&A statements for each year should provide:

- Base, outage and project OM&A separately. Where applicable, the information is to include a breakdown by major functions or divisions and the allocations to each of the prescribed nuclear and hydroelectric businesses.~~A breakdown on a work basis of each major item that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million~~
- Detailed information is to be provided for each expense incurred through the purchase of services or products that meets the threshold ~~of the lesser of 1% of total expenses before taxes or~~ $~~2~~30 million. The information is to include, for each such expense:
  - A summary of the tendering process used
  - If a tendering process was not used, an explanation of why that was the case as well as a description of the pricing methodology used
  - The identity of the company transacting with OPG
  - A summary of the nature of the activity transacted

  In addition, the annual dollar value, in aggregate, for all such expenses should be provided.

Commented [A51]: Note for stakeholders: Seeking feedback on whether this OM&A project cost threshold is still appropriate. The threshold was set in 2011.

Commented [A52R51]: OPG addressed the Project OM&A threshold above in Section 6.

Commented [A53]: For clarity - no substantive change relative to current OPG evidence. As discussed at the stakeholder session and agreed to with intervenors present, the prior language did not reflect OPG's historical applications. Parties felt that OPG's existing evidence was appropriate. Accordingly, OPG has proposed amendments for alignment with OPG's existing evidence to ensure comparability of OPG's applications continues going forward.

Commented [A54]: OPG proposes to modify and increase the threshold from "the lesser of 1% of total expenses before taxes or $20 million", to $30 million. The removal of the 1% rule simplifies the rule and makes it more comparable case over case. Based on Consumer Price Indices, $20 million in 2011 would be equivalent to approximately $30 million today. OPG believes this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and helps manage regulatory efficiency for both OPG and intervenors in focusing on material issues in the application.

- A breakdown of employees by the following groups: number of full-time equivalents (FTEs) including contributions from part time employees; total salaries, wages and benefits; and salaries, wages and benefits charged to OM&A. In addition, the following should also be provided:
  - Total compensation by employee group and average level per group
  - Details of any pay-for-performance or other employee incentive program
  - The status of pension funding and all significant assumptions used in the analysis

  Information should be presented in terms of FTEs. In some cases, OPG may choose to provide the information in terms of head count as well as FTEs. The basis for each breakout of compensation data will be specified:
  - Head count or FTE
  - Yearly average, mid-year or year end

  This data should be provided in Excel spreadsheet table format.

- Employee benefit programs, including pensions, and costs charged to O&M should include the following details:

  - Historic actuarial reports
  - Actuarial evidence to support pension and other post-employment benefits (OPEB) expense for the Bridge Year and Test Year(s) including any educational notes or articles issued by the Canadian Institute of Actuaries on methods for determining discount rates used for reporting under Chartered Professional Accountants (CPA) Canada standards
  - CPA Canada guidance, practice notes, etc. that provide information on approaches to selecting discount rates should be filed
  - Discussion and analysis on discount rates used for calculating pensions and OPEB benefit obligations, cost for the year and liabilities
  - A table that summarizes actual accounting expense compared to OEB-approved expense and with amounts actually paid for pensions and OPEBs for the historical years
  - The most recent report filed with Financial Services Regulatory Authority of Ontario

- A variance analysis for OM&A, and components of OM&A (including asset service fees, regulatory affairs costs), should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year variance analysis

Commented [A55]: Minor clarification. This is not intended to result in any changes to the scope or level of detail of OPG's pension related evidence.

Commented [A56]: As discussed above, OPG can provide both the new term-over-term variance analysis, and also continue to provide year-over-year variance analysis.

- Term-over-term variance analysis (most recent payment amounts application versus the proposed payment amounts application)
- A written explanation is required for any variance greater than or equal to 10% of category expenses

8.3 Depreciation/Amortization/Depletion

This section should include the following:

- An independent depreciation study and summary of changes for depreciation, amortization and depletion by asset group should be provided
- Details of provision for depreciation, amortization and depletion by major ~~asset group~~function or division for each Test Year should be provided, as should comparative data for each of the Historic Years and the Bridge Year, including asset amount and rate of depreciation

Commented [A57]: Minor clarification to align with the proposal for section 4.1 (gross plant). In OPG's past applications, depreciation tables follow the presentation of the rate base schedules given their connectedness. As noted earlier, detailed plant account listing and associated depreciation rates are provided in depreciation studies.

8.4 Corporate Cost Allocation

A summary of the corporate cost allocation should be provided, including information showing the costs incurred at the corporate level, the methodology and assumptions used ~~to allocate these costs to the prescribed and non-prescribed generation facilities and the methodology~~ to allocate these costs to each of the prescribed nuclear and hydroelectric businesses.

Commented [A58]: For clarity. Corporate costs are allocated directly to each of the prescribed nuclear and hydroelectric businesses, not as a two step process.

Details in relation to shared corporate services should include:

- Type of service (IT, office space, etc.) or function/division
- Total annual expense by service or function/division
- Rationale and derivation of cost allocators used for shared costs, for each type of service (square footage/computers/headcount/etc.)
- Any variances for corporate cost allocation for the two most recent years from filing date of the current payment amounts application

Commented [A59]: Minor clarification to align with how OPG's applications present corporate cost information and to ensure comparability in future applications

8.5 Taxes

OPG should file information on its income tax for the Historic Years, the Bridge Year and the Test Year(s) and the detailed calculation supporting the data. The documentation should include copies of the most recent tax returns and notices of assessment, re-assessment and statements of adjustments.

A detailed tax calculation should be provided for each of the Historic Years, the Bridge Year and the Test Year(s), including derivation of interest deducted, capital cost allowance showing differences from depreciation/amortization expense, all other

material differences from regulatory ~~financial statement~~ income, tax rates and payments in lieu of taxes included in deriving the revenue requirement.

Details on the gross revenue tax applicable to the hydroelectric business should be provided either separately or as part of the operating expenses for the hydroelectric business.

Where applicable, ~~All~~ reconciling items should have supporting schedules and calculations.

Commented [A60]: This clarification aligns to the evidence in past applications where some smaller differences are aggregated to help manage information presented.

Commented [A61]: In this exhibit, the starting point for regulatory taxes is regulatory income. Reconciliation between regulatory income and the AFS financial results is captured by the requirements under section 3.2.

Commented [A62]: Currently, OPG is providing supporting schedules and calculations for CCA. This leaves open for other items to have supporting schedules as required.

9. Exhibit G ~~Operating~~Other Revenue

~~The revenue forecast, any normalization methodology and sales activities should be provided here.~~ The information presented in this section should include other revenue derived from the use of the prescribed generation facilities as well as from the Bruce nuclear generating stations, broken down by revenue source.

~~9.1 Energy Revenue~~

~~This section should include the following:~~

- ~~Production and energy revenues for the Historic Years, the Bridge Year and the Test Year(s)~~
- ~~Schedule of production showing volumes, total revenues and unit revenues for each of the Historic Years, the Bridge Year and the Test Year(s)~~

~~9.2~~9.1 Other Revenues

Details of other revenue, broken down by revenue source, should be provided. This should include OPG's revenues and costs associated with the Bruce nuclear generating stations

- A variance analysis of other revenues should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year over the Historic Years, the Bridge Year and the Test Year(s)
- A detailed explanation of how other revenues are attributed to the prescribed generation facilities should be provided

Commented [A63]: Note for stakeholders: Seeking feedback on the organization of this section. The organization of this exhibit is not consistent with how OPG has structured its most recent payment amounts application (2022-2026 term).

In that application, the exhibit solely focused on other revenues. E.g., Bruce, sale of isotopes etc. The broader pieces on operating revenue were rolled into other Exhibits

Commented [A64R63]: As discussed at the stakeholder session with intervenors, parties agreed that the current evidence structure as reflected in OPG's applications is appropriate, and that it would facilitate comparability application over application to revise the Filing Requirements to reflect the structure of OPG's evidence. The proposed edits reflect this shared view.

Commented [A65]: Minor clarification as Bruce facilities are not prescribed.

Commented [A66]: Note for stakeholders: Seeking feedback on whether year-over-year variance analysis is needed and/or term over term for Other Revenue.

Commented [A67R66]: For the same reasons set out above in section 2.7, OPG believes that year-over-year analysis would be more meaningful in this instance. OPG believes no change is needed.

10. Exhibit H Deferral and Variance Accounts

As described in section 1, O. Reg. 53/05 contains a number of provisions regarding the establishment of deferral and variance accounts (DVAs) and the recovery of balances in those accounts. In this section, OPG should include information necessary to enable the OEB to deal with these accounts in the manner contemplated by O. Reg. 53/05, including OPG's proposals regarding the following, as applicable:

- The end date for entries into the DVAs
- Addressing timing differences between the end date for entries into the DVAs and the effective date of the OEB's order
- The number of years over which balances in the DVAs should be recovered (subject to the maximum set out for each in O. Reg. 53/05)

- ~~The interest rate proposed for the nuclear liability deferral account referred to in section 5.2(1) of O. Reg. 53/05~~

For existing DVAs, this exhibit should include:

- A listing and detailed description (including account definition) of all outstanding DVAs - those required by O. Reg. 53/05 as well as those established by the OEB in previous decisions
- Continuity statements listing opening balances, transaction details including recoveries where applicable, interest rates and carrying charges, and closing balances. The schedules should reflect annualized data for the Historic Years ~~and the Bridge Year~~since the balances were last cleared. ~~Notes~~ Information should be provided for any transactions that are outside the normal course of business for OPG or that otherwise appear to be unusual due to their timing, size, or nature
- A detailed proposal for the disposition of the balances in the DVAs, where applicable.

OPG should also identify any deferral or variance accounts that it may wish to have authorization to establish on and after the date of the OEB's order.

Commented [A68]: Minor clarification as not all of the items would necessarily apply to all account or at all times

Commented [A69]: Cleanup - This has already been resolved in prior applications.

Commented [A70]: Note to stakeholders: The list of DVAs have been removed in efforts to keep the Filing Requirements evergreen.

Commented [A71R70]: OK

Commented [A72]: Edits to clarify that balances are cleared periodically, on an actual basis. Information is therefore not presented on a Bridge Year basis in OPG's application, and Historic Year information goes back to the last OEB approval.

Commented [A73]: Minor clarification as this information in practice may be provided by a combination of notes to the tables and narrative evidence, depending on the nature of the item

11. Exhibit I Determination of Payment Amounts

This exhibit should include the following:

- Calculation of Revenue Deficiency or Sufficiency
  - Determination of regulatory net income
  - Statement of rate base
  - Indicated rate of return
  - Gross and net deficiency or sufficiency in revenue
  - Revenue Requirement Work Form
- Proposed Payment Amounts Schedule and Analysis
  - Proposed payment amounts and revenue adjustments
  - Proposed approach for smoothing payment amounts, if applicable
  - Detailed calculations of revenue under the current payment amounts schedule and the proposed payment amounts schedule
  - Detailed reconciliation of payment amounts revenue and other revenue to the total revenue requirement
  - Analysis of % change in proposed payment amounts vs. current payment amounts
  - Bill impact analysis
- Payment Design (if proposing changes)
  - Analysis of the existing design of payment amounts and whether the design maximized efficient use of the prescribed generation facilities
  - Proposed payment design and rationale
  - Explanation of non-cost factors and their application to payment design
- Payment Implementation

  OPG should provide a description of the settlement process with the IESO, including a description of the timelines associated with the requested effective date.

Commented [A74]: Minor clarification.

Commented [A75]: This section is unnecessary unless changes to payment design are contemplated. It would be repetitive application over application otherwise.

Board Staff Interrogatory #322

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 37-44

Preamble:

At Reference 1, OPG states:

> The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington's number of operating units rather than a four-unit site. OPG is performing a mid-life refurbishment at Darlington, which involves bringing units offline for the replacement of certain life-limiting components. It is necessary to normalize these metrics during refurbishment to allow for comparisons to prior site performance and industry peers, given reduced generation and no corresponding decline in fixed costs.

Question(s):

a) For each year from 2021-2023, please provide a table showing the adjustment made to each affected cost category.

b) Aside from the Darlington site, please provide a list of all plant refurbishments affecting the 57 nuclear sites studied by ScottMadden from 2006 to 2023.

c) Aside from the Darlington site, please confirm that no refurbishment normalizations have been applied to the costs of any other site.

Response

a) Chart 1 below shows the adjustments made to each Total Generating Costs cost category for Darlington's Refurbishment normalization methodology for the years 2021-2023.

Chart 1: Refurbishment Normalization Methodology – Darlington

2024 Benchmarking Report ($K)	Annual			3-Year
	2021	2022	2023	2023
OM&A	1,066,820	902,440	982,563	2,951,823
Capital	326,294	454,447	547,277	1,328,018
Non-Normalized (Sub-Total)	1,467,101	1,409,975	1,593,117	4,470,192
Refurbishment Adjustment - OM&A	(191,488)	(325,926)	(370,301)	(887,715)
Refurbishment Adjustment - Capital	(87,868)	(259,891)	(313,576)	(661,335)
Refurbishment Adjustment (Sub-Total)	(279,356)	(585,817)	(683,877)	(1,549,050)
Normalized – OM&A	875,331	576,514	612,262	2,064,108
Normalized - Capital	238,426	194,556	233,701	666,683
Total Normalized OM&A & Capital	1,113,758	771,069	845,963	2,730,790

b) Refer to Ex. L-F2-Staff-328, part b).

c) Confirmed.

Board Staff Interrogatory #323

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 7

Preamble:

At Reference 1, OPG states that ScottMadden analyzed eighteen years of Electric Utility Cost Group (EUCG) data (from 2006-2023) for OPG and it indicated that Canada Deuterium Uranium (CANDU) technology increases predicted Total Generating Cost (TGC) by over $539 million per year relative to non-CANDU plants and each month of average unit age increases predicted TGC by $77,000 per year. ScottMadden then adjusted the EUCG data to normalize for these factors.

At Reference 2, it illustrates the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

Question(s):

a) Please clarify if the above updated study and normalization methodology applies to both Darlington's and Pickering's normalized TGC calculation in 2023 and their annual target calculation in 2026-2031.

b) Given the differences between the reactor design of the units at Pickering and Darlington, please clarify if there is any difference to account for the CANDU technology costs impact in the TGC normalization calculations between the two stations.

c) Given that Pickering will start refurbishment in late 2026, please clarify if any normalization is developed and applicable to Pickering's refurbishment project and its annual normalized TGC calculation in 2027-2031. If so, please provide calculation details similar to the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

Response

a) ScottMadden's updated study and normalization methodology applies to both Darlington and Pickering's normalized TGC/MWh calculations in 2023, as shown in Ex. F2-1-1, p. 11, Darlington's annual target calculations for 2026-2031 and to

Pickering's 2026 target calculations. Pickering does not have annual Value for Money targets during the IR term, including for normalized TGC/MWh, as discussed in Ex. L-F2-Staff-183.

b) No, there is no difference for the technology normalization adjustment between Pickering and Darlington, as both stations use CANDU technology.

c) No, normalizing TGC/MWh is not applicable to Pickering during refurbishment over the IR term, as discussed in Ex. L-F2-Staff-183. As noted in part a), Pickering does not have Value for Money targets for 2027-2031.

Board Staff Interrogatory #324

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / pp. 8-9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / pp. 6-7

Preamble:

In Reference 1, OPG explains that ScottMadden conducted econometric analyses of Electric Utility Cost Group (EUCG) data for OPG and its industry peers to assess whether and to what extent site characteristics influence total generating cost (TGC) over time, and to normalize observed costs for those characteristics. In an earlier analysis using nine years of EUCG data (2009–2017), ScottMadden found that "CANDU technology increases predicted TGC by over $250M per year relative to non-CANDU plants, and each month of average unit age increases predicted TGC by $346,000 per year". In the current study, an expanded eighteen-year dataset (2006–2023) is used. ScottMadden reported "CANDU technology increases predicted TGC by over $539M per year relative to non-CANDU plants and each month of average unit age increases predicted TGC by $77,000 per year." In both cases, ScottMadden then adjusted the EUCG data to normalize these factors.

At Reference 2, ScottMadden notes in footnote 3 that the prior study's Canada Deuterium Uranium (CANDU) adjustment was $283.9 million in 2017 dollars, which inflation-adjusted to 2023 dollars would be ~$343.3 million — still substantially below the current $539 million figure. The document does not explain the factors driving this ~57% real increase in the CANDU technology cost penalty. Reference 2 also notes that there are only three CANDU plants in the 57-site EUCG dataset.

Question(s):

a) Please explain why a different data period is used in the current study.

b) Please confirm if the same set of "industry peers" is used in both analyses.

c) Regarding Reference 3, please explain step by step how ScottMadden arrived at the Plant Weighted Age variable found in the Weighted Performance Calcs tab.

d) Please explain the driving factors of the differences in the effect of average unit age on predicted TGC in the 2018 study and the 2025 study.

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e) Please identify and quantify the factors that account for the increase in the CANDU technology adjustment from ~$343 million (2018 study, inflation-adjusted to 2023 dollars) to ~$539 million (2025 study, 2023 dollars), distinguishing between the effect of: (a) the expanded dataset period (9 years vs. 18 years), (b) changes in the composition of the EUCG peer panel, (c) actual cost increases at CANDU plants relative to Pressurized Water Reactor/Boiling Water Reactor peers, and (d) any other contributing factors.

f) Given that there are only three CANDU generating stations in the 57-site EUCG dataset, please discuss how ScottMadden assessed the statistical reliability of a coefficient derived from three generating stations within a dataset of 57 sites.

Response

The following responses (a-f) were prepared by ScottMadden Management Consultants:

a) ScottMadden included 18 years of data, compared to nine years of data used previously, because increasing the amount of data improves the accuracy, stability, and predictiveness of the model derived from that data.

b) While the peer panels are similar in both analyses, they are not the same. The 2018 study used a 63-site EUCG panel consisting of 37 PWR sites, 23 BWR sites, and 3 CANDU sites. The 2025 study used a 57-site EUCG panel consisting of 34 PWR sites, 20 BWR sites, and 3 CANDU sites. The variance of six is due to plant closures.

c) The Plant Weighted Age variable is calculated as a capacity-weighted average unit age at the plant-year level.

The steps are:

1. For each unit and year in the “IAEA Unit Data and Weighting” tab, determine the unit’s Commercial Start date and the applicable Aging End Date for that year.
2. Calculate Unit Age (Months) as the number of months between Commercial Start and Aging End Date for that unit-year.
3. For each unit-year, multiply Unit Age (Months) by Rated Unit Power (RUP) to create Weighted Age. This is shown as:
   Weighted Age = Unit Age (Months) × RUP
4. Aggregate those unit-level weighted ages to the plant-year level by summing Weighted Age across all units at the plant. In the workbook, this is on the ‘Weighted Performance Calcs” tab in the ‘Sum of Weighted Age” field.

5. Sum RUP across all units at the plant for the same year. In the workbook, this is on the 'Weighted Performance Calcs" tab in the 'Sum of RUP" field.
6. Compute Plant Weighted Age as:

$$Plant\ Weighted\ Age = \frac{\Sigma(Unit\ Age\ in\ Months\ \times\ RUP)}{\Sigma \mathrm{RUP}}$$

7. That plant-year result is then brought into the "Master Compilation" tab as Plant Weighted Age, and the R script uses that field directly in the regression model. The script then estimates TGC as a function of Plant_Weighted_Age, site capacity, and reactor type.

d) The main driving factor of the difference in the effect of average unit age on predicted TGC between the current study and the 2018 study is due to changes in the underlying dataset and the statistical relationships within that dataset. When the dataset was expanded from 2009–2017 to 2006–2023 and the peer panel changed, these relationships changed. In particular:

- If age becomes more correlated with other variables in the model (e.g., capacity or reactor type), the regression will attribute less independent effect to age
- If the marginal relationship between age and TGC weakens in the expanded dataset, the estimated coefficient on age will decrease.

Consistent with this, the current model results show that the age coefficient is substantially smaller and is less statistically significant, indicating that once capacity and reactor type are controlled for, age explains less incremental variation in TGC in the updated model. Accordingly, the reduction in the age adjustment reflects a reallocation of explanatory power within the regression model, rather than a change in methodology.

e) To assess the drivers of the increase, ScottMadden performed additional sensitivity analysis using consistent model specifications across different time periods. The results are summarized below (all values in thousands of Canadian dollars):

Study	Period	Basis	CANDU Coefficient
Prior Study	2009-2017	2017$Ck	283,946
Prior Study (with Infl'n Adj)	2009-2017	2023$Ck	343,291
Current Study	2006–2023	2023$Ck	539,468
Current Study (same starting point)	2009–2023	2023$Ck	555,768

These results indicate the following:

(a) & (c) Expanded dataset period & CANDU relative to PWR/BWR (primary driver)

The increase in the CANDU technology adjustment reflects the re-estimation of the regression model using more recent data. As the CANDU adjustment is the estimated coefficient on the CANDU indicator variable, changes in this value arise from changes in the underlying dataset and the statistical relationships within that dataset.

From a regression perspective, this is captured through:

- Changes in the relative costs between CANDU and PWR/BWR plants, and
- How those differences interact with other variables in the model (e.g., capacity and age).

(b) Changes in EUCG peer panel composition (limited impact)

The only change in the peer panel was to remove plants that are no longer in commercial operation. The 57 plants in the current peer panel were also present in the prior peer panel. Six plants ended commercial operation between this report and the prior report.

f) Although there are only three CANDU sites, it reflects three quarters of the CANDU plants in North America and the regression is estimated on 54 CANDU site-year observations over 2006-2023, within a total sample of 1,026 plant-year observations.

The statistical reliability of the CANDU coefficient in the current regression is supported by the regression output itself:

Estimated CANDU coefficient: C$539.5 million
Standard error: C$32.1 million
t-statistic: 16.8
p-value: $< 2e^{-16}$
Approximate 95% confidence interval: C$476 million to C$603 million

So, while the number of distinct CANDU stations is small, the coefficient is estimated very precisely in the plant-year panel actually used in the model. However, because the CANDU coefficient is identified from only three sites, it necessarily captures not only reactor-technology differences, but also any persistent CANDU-site characteristics that are not separately controlled for and that are common to those Canadian stations, such as regulatory environment, operating context, and other structural differences. The 2025 report notes that CANDU plants differ from PWR/BWR plants in several relevant ways, including unit configuration, outage/maintenance requirements, and operation in Canada under a different regulatory and market environment.

Board Staff Interrogatory #325

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 6 / footnote 2

Preamble:

At Reference 1, ScottMadden states "[w]e do not adjust costs for differences in site capacity, despite this being a significant driver of cost, since this would also have required a complex adjustment to generation."

Question(s):

a) Please explain why MW capacity was included in the econometric model if no adjustment to total generating cost (TGC) was made.

Response

The following response was prepared by ScottMadden Management Consultants:

a) Larger plants generally have higher total costs. By including capacity in the model, ScottMadden was able to account for this relationship and more accurately isolate the impact of other factors, such as reactor type and unit age.

   However, ScottMadden did not adjust TGC for capacity in the benchmarking results because doing so would also require adjusting generation (MWh) in a consistent way. Specifically, adjusting TGC for capacity without making a consistent adjustment to generation would distort the TGC/MWh metric, as capacity directly influences both the numerator (cost) and denominator (generation).

   So, capacity was included in the model to improve its explanatory power but not used as a normalization factor in order to keep the benchmarking approach straightforward and transparent.

Board Staff Interrogatory #326

Interrogatory

Reference:
Ref 1: Cost Model - With Formulas - BWR Base v4 (For OEB).xlsx
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4

Preamble:

Reference 1 forms part of the confidential working papers that support ScottMadden's Nuclear Cost Performance Benchmarking study, Reference 2.

Question(s):

a) In the calculation of TGCperMWhOutageAdjusted within the "Cost per MWh Calcs" tab, please confirm whether or not Total_Generating_Costs is adjusted for inflation.

Response

The following response was prepared by ScottMadden Management Consultants:

a) Confirmed. Total_Generating_Costs is adjusted for inflation.

As described in the ScottMadden report at Ex. F2-1-1, Attachment 4, p. 8, all Total Generating Cost (TGC) values are converted to a common dollar basis (2023 dollars) prior to performing the econometric analysis and related calculations.

Board Staff Interrogatory #327

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 11
Ref 2: Master Data Adjusted For 0 Generation - ORIGINAL.xlsx
Ref 3: OPG Regression Analysis v0.07 (For OEB).R

Preamble:

At Reference 1, ScottMadden states:

> All reactor types have planned maintenance outages on either 18, 24, 30, or 36-month cycles. Planned maintenance outages for PWRs and BWRs are incorporated into refueling cycles and occur every 18 or 24 months. Planned maintenance outages for CANDU reactors occur every 24, 30, or 36 months. Work to significantly extend the operating life of a plant (life-extension activities) is also approached differently across technologies. For PWR and BWR plants, it is more common to complete this work as part of planned refueling and maintenance outages over a series of multiple outages to minimize time in outage. The scope for this work also differs from one plant to the next due to differences in plant design, market construct, and other factors. Comparable life-extension activities for CANDU plants largely occur during long-duration refurbishment outages where multiple, major plant components are replaced, though some related work can also be incorporated into more frequently recurring planned maintenance outages.

Question(s):

a) Please explain why OPG Regression Analysis v0.07 (For OEB).R defines Planned_Outage_PCT using Outage_Hours rather than Planned_Outage_Hrs.

b) Please explain the difference between Outage Hours and Total Outage Hrs in Master Data Adjusted For 0 Generation - ORIGINAL.xlsx, tab “Master Compilation.” Please confirm that ScottMadden is using Outage Hours in its Nuclear Outages Analysis.

c) Using the sourcedataoutage data frame in OPG Regression Analysis v0.07 (For OEB).R, CAEC calculated the average share from 2006 to 2023 of planned outage hours (Planned_Outage_PCT) and the average age (Plant_Weighted_Age) for the three CANDU sites. To the extent that planned maintenance outages for CANDU reactors occur on a fixed schedule as described above, please explain the variation in average Planned_Outage_PCT across these three sites. In particular, despite

having similar plant ages, explain why plant 967 and the Pickering plant have significantly different planned plant outage percentages.

d) Regarding Reference 3 and the Darlington plant capacity and planned outage percent from 2006 to 2023.
   i. Please explain how Planned_Outage_PCT is related to the mid-life refurbishment projects at the Darlington plant.
   ii. Please confirm that such projects affect reported capacity and MWh.

Response

The following responses (a-d) were prepared by ScottMadden Management Consultants:

a) 'Planned Outage Hrs', 'Unplanned Outage Hrs', 'External Outage Hrs', and 'Total Outage Hours' were derived from International Atomic Energy Agency ("IAEA") data. Whereas Outage_Hours reflects the outage hours as reported in Electric Utility Cost Group ("EUCG").

   For consistency, EUCG data was the data source used throughout this analysis.

b) Outage_Hours reflects actual hours incurred for planned refueling/maintenance outages reported through EUCG; and 'Total Outage Hrs' is a calculated value derived from a separate data source (IAEA-based unit-level data).

   Confirmed, Outage_Hours from EUCG data was the data source used throughout this analysis.

c) While CANDU reactors follow planned maintenance outage cycles, the outage percentages used in the analysis are based on actual reported planned (not forced) outage hours in the EUCG dataset, rather than a standardized or assumed outage schedule (e.g., 24-,30-, or 36-month intervals).

   In the prior study, ScottMadden relied on survey responses from operators to estimate planned outage durations by reactor type and maintenance (or refueling) cycle. In contrast, the current analysis used actual reported planned outage hours over the 2006–2023 period. The methodology then normalized plants to the level of the best-performing (i.e., lowest percentage of actual planned outage hours) plant rather than using assumed values based on survey responses.

   As a result, the calculated Planned_Outage_PCT reflects observed plant performance over time, which can vary across sites for several reasons, including:

- Differences in outage scope and execution from one cycle to the next
- Differences in plant configuration (e.g., number of units and unit size)
- Differences in operating practices and site-specific conditions across plants

Accordingly, even where plants have similar average unit ages and follow broadly similar outage cycles, it is expected that their observed outage percentages will differ when measured using actual historical outage hours over a long period.

In this context, the variation observed between plant 967 and Pickering reflects differences in their actual outage experience over the 2006–2023 period, rather than a difference in the underlying outage cycle framework.

d)

i. Planned_Outage_PCT is calculated using reported outage hours related to the units in service. For the Darlington mid-life refurbishment, individual units were taken offline for extended periods. This time is not reported in the outage figures. To account for the offline units in refurbishment, the number of units associated with the plant were reduced proportionately in the affected years. In other words, if one unit was offline for the whole year, the units figure was reduced from ‘4’ to ‘3’.

ii. Confirmed, these projects reduced the plant capacity and MWh reported in the EUCG data.

Board Staff Interrogatory #328

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 12

Preamble:

At Reference 1, ScottMadden states:

> ScottMadden adjusted the MWh values for all 57 sites from 2006-2023, as described above, to account for the impact of differences in planned outage durations across technology types and outage frequencies. In addition, the Darlington Refurbishment accounted for significant time in planned outage, but this outage time was captured in the reported unit capacity each year, so no further capacity adjustments were needed.

Question(s):

a) Please explain what is meant by "the Darlington Refurbishment accounted for significant time in planned outage, but this outage time was captured in the reported unit capacity each year, so no further capacity adjustments were needed."

b) Did ScottMadden consider whether or not such capacity adjustments were needed for other sites in the sample in addition to the Darlington site? If not, please explain.

Response

The following responses (a-b) were prepared by ScottMadden Management Consultants:

a) This statement means that the impact of the Darlington refurbishment was already reflected in the data used for the analysis.

During refurbishment, one or more units at Darlington were offline for extended periods. In the dataset, this was captured through reduced reported capacity (i.e., fewer operating units or lower available MW) in those years. As a result, both the reported generation (MWh) and the effective capacity of the plant already reflect the refurbishment outages.

Because the outage impact was already embedded in the reported capacity and generation data, ScottMadden did not need to make an additional, separate adjustment to capacity for those refurbishment periods. Doing so would have risked double-counting the effect.

b) ScottMadden did not apply similar MW capacity-related adjustments for other sites in the sample. While other plants in the EUCG dataset have undertaken life-extension activities during the data window, these activities were not treated in the same manner. We did not have detailed cost data associated with these life extension projects at other plants and thus did not and could not remove these costs from their TGC as we did for Darlington. Furthermore, when applying model-derived downward adjustments for these plants, we did not reduce the size of these downward adjustments based on the associated costs for life-extension work. This combination of factors (i.e., higher TGC as a result of not removing life extension costs and additional reduction in TGC from full application of model-derived adjustments) made us comfortable that the comparison was still appropriate.

SEC Interrogatory #177

Interrogatory

Reference:
F3-1-1, Table 1-3c

Question(s):

With respect to Corporate Support & Administrative Groups OM&A Costs, is Table 1 (OPG) the costs of OPG regulated facilities or all OPG costs (regulated and unregulated)? If the latter, please explain why the totals in Table 1 (OPG) are not the sum of Tables 2 (Regulated Hydroelectric), Table 3 (OPG Nuclear Facilities) and Table 3c (DNNP Facilities).

Response

Exhibit F3-1-1, Table 1 represents total OPG Corporate Support & Administrative Services OM&A costs (regulated and unregulated) and therefore does not sum to such Table 2 (Regulated Hydroelectric), Table 3 (OPG Nuclear Facilities) and Table 3c (DNNP Facilities), which reflect only the regulated businesses.

SEC Interrogatory #178

Interrogatory

Reference:
F3-1-1
F3-1-2

Question(s):

With respect to support services and asset service fees, OPG has only provided the allocated amounts of the total OPG costs for hydroelectric to 2027.

a. [F3-1-1] Please expand Tables 2, 5, and 7b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.

b. [F3-1-2] Please expand Table 1b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.

Response

a) and b)

OPG declines to expand the referenced Tables 2, 5, 7b or Table 1b to include amounts allocated to the regulated hydroelectric facilities for the 2028-2031 period. Under the proposed regulated hydroelectric rate-setting methodology, OM&A costs and certain other revenue requirement elements are relevant for the 2027 test year only (Ex. A1-3-2, Section 2.0). As such, support services costs and asset service fees allocated to the regulated hydroelectric facilities for the 2028-2031 period are not relevant to the Application.

SEC Interrogatory #180

Interrogatory

Reference:
F3-1-4, Attachment 1, p. 12

Question(s):

Please provide a live copy of the referenced OPG cost allocation model with all formulas intact.

Response

OPG does not maintain a separate "live" cost allocation model in the form of a standalone spreadsheet or similar file that can be produced with formulas intact. The cost allocation methodology and related computations are implemented and executed within OPG's SAP Business Warehouse ("BW") environment.

The BW environment is SAP's enterprise data warehousing and reporting platform that consolidates data from SAP and non-SAP source systems, applies data translations and business rules, and produces outputs based on defined logic and parameters through centrally managed data models and queries rather than spreadsheet-based formulas.

SEC Interrogatory #181

Interrogatory

Reference:
F3-2-1

Question(s):

With respect to Asset Service Fees ("ASF"):

a) [p.1] The evidence states, "[t]he ASF methodology considers that to the extent that 90% or more of the beneficial use of joint-use asset relates to a particular business, the related assets are fully attributed to that business." Does this mean that an asset is used 91% by the regulated business, and 9% by an unregulated business, therefore the unregulated business bears no cost of the asset? If, so please explain why that is appropriate.

b. [p.3-6] Please provide the underlying calculations used to determine the other costs, depreciation expense and tax-adjusted return for each of the Corporate Headquarters and Corporate IT ASF to each of the regulated segments (nuclear, DNNP, and hydroelectric)

Response

a) Confirmed.

If 90% or more of the beneficial use of a joint-use asset relates to the regulated hydroelectric business, the asset is included in the regulated hydroelectric rate base. This "dominant use" approach has been consistently applied in all OPG payments amounts proceeding beginning with EB-2013-0321, when 48 additional hydroelectric facilities were prescribed for regulation by the OEB under Ontario Regulation 53/05. These additional facilities and their associated supporting infrastructure such as controls dams and service centres had been in existence for many years prior to OPG's contracted hydroelectric facilities, which may share the use of these assets, being constructed in the province. The "dominant use" approach reflects the cost allocation principle of causation, given that the existence of an asset is effectively caused by the particular business that requires greater than 90% of the usage of that asset.

The treatment of OPG's joint-use assets, including hydroelectric joint-use assets, was reviewed by Elenchus Research Associates Inc. ("Elenchus") as part of their assessment of OPG's cost allocation methodology, filed at Ex. F3-1-4, Attachment 1, Section 3.5, where Elenchus found that this treatment "remains reasonable given the operation of OPG's business and is consistent with cost causality principles."[1]

b) The underlying calculations used to determine the Corporate IT ASF are provided for each of the regulated segments within the Ex. F3-2-1, Table 5. The underlying calculations used to determine the Corporate Headquarters ASF for each of the regulated segments can be found in Attachment 1.

[1] This treatment of joint-use assets was also reviewed by HSG Group Inc. in EB-2013-0321 (Ex. F5-5-1, p. 25).

Attachment 1

OPG Corporate Headquarters Asset Service Fee Calculation

			OPG Nuclear Facilities					DNNP Facilities					Regulated Hydroelectric
Line	**Component**	**Reference**	**2027**	**2028**	**2029**	**2030**	**2031**	**2027**	**2028**	**2029**	**2030**	**2031**	**2027**
1	Total Depreciation		5.0	5.4	5.8	6.0	6.2	5.0	5.4	5.8	6.0	6.2	5.0
2	% Allocated		71.4%	70.8%	71.0%	69.5%	71.2%	8.8%	10.1%	9.6%	10.2%	3.8%	13.4%
3	ASF Depreciation	Line 1 x Line 2	3.6	3.8	4.1	4.2	4.4	0.4	0.5	0.6	0.6	0.2	0.7
4	Total Property Tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
5	ASF Property Tax	Line 4 x Line 2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Cost of Capital												
6	Net Book Value		195.8	206.4	203.0	199.3	195.4	195.8	206.4	203.0	199.3	195.4	195.8
7	Cost of Debt	For OPG Nuclear and Reg. Hydro: Line 6 x Ex. C1-1-1 Tables 1-5, col. b), Line 4 x Ex. C1-1-1 Table 5, col. c), Line 4 For DNNP: Line 6 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 3 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 3	4.3	4.7	4.8	4.7	4.7	0.0	0.0	0.0	0.0	0.0	4.3
8	Return on Equity	For OPG Nuclear and Reg. Hydro: Line 6 x Ex. C1-1-1 Table 5, col. b), Line 5b x Ex. C1-1-1 Tables 1-5, col. c), Line 5a For DNNP: Line 6 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 4 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 4	9.3	9.8	9.6	9.4	9.3	17.8	18.8	18.5	18.2	17.8	9.3
9	Total Cost of Capial		13.6	14.5	14.4	14.2	13.9	17.8	18.8	18.5	18.2	17.8	13.6
10	ASF Cost of Capital	Line 9 x Line 2	9.7	10.3	10.2	9.9	9.9	1.6	1.9	1.8	1.9	0.7	1.8
11	Tax gross up	Line 8 * (25% / (1 -25%)) * Line 2	2.2	2.3	2.3	2.2	2.2	0.5	0.6	0.6	0.6	0.2	0.4
12	ASF Tax-Adjusted Cost of Capital	Line 10 + Line 11	11.9	12.6	12.5	12.0	12.1	2.1	2.5	2.4	2.5	0.9	2.2
13	Operating Costs		7.6	7.7	7.9	8.0	8.1	7.6	7.7	7.9	8.0	8.1	7.6
15	ASF Operating Costs	Line 13 x Line 2	5.4	5.5	5.6	5.6	5.8	0.7	0.8	0.8	0.8	0.3	1.0
16	Total OPG Corporate Headquarters ASF	Line 3 + Line 5 + Line 12 + Line 15	21.1	22.1	22.4	22.0	22.6	3.2	3.9	3.7	3.9	1.5	4.0

SEC Interrogatory #182

Interrogatory

Reference:
F3-2-1, Table 1

Question(s):

With respect to Asset Service Fees ("ASF"):

a) Please provide the number of IT-end users for nuclear, DNNP, and hydroelectric which are used to allocate IT related Support Services costs under OPG's cost allocation methodology.

b) Please explain the increase in Joint-use Renewable Generation Assets allocated to Regulated Hydroelectric in 2023.

Response

a) The number of IT-end users for OPG's nuclear facilities, the DNNP facilities and OPG's regulated hydroelectric facilities as used under OPG's cost allocation methodology in this Application is provided in Chart 1. As OPG does not forecast IT-end users, these figures are derived by using available actual IT-end users at a point in time, assigned by the applicable categories in Chart 1, and then extrapolating on a forecast basis by the change in FTEs in the respective categories. This approach has been found to be applied "in a consistent manner" by Elenchus Research Associates Inc. as part of their assessment of OPG's cost allocation methodology (Ex. F3-1-4, Attachment 1, p. 15).

Chart 1 – IT End-users Cost Driver

	2027	2028	2029	2030	2031
OPG Nuclear Facilities	10,017	9,790	9,874	9,857	10,404
DNNP Facilities	718	776	674	575	581
OPG Regulated Hydroelectric	1,164	1,164	1,139	1,139	1,126

b) The increase in the Joint-use Renewable Generation ("RG") ASF in 2023 is largely due to the in-service of the RG Monitoring and Diagnostic Centre used to monitor the performance of systems and components of the RG stations in support of shifting to more advanced condition-based maintenance strategies.

Witness Panel: Compensation and Corporate Costs

Board Staff Interrogatory #217

Interrogatory

Reference:
Ref 1: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 17
Ref 2: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 27

Preamble:

At Reference 1, Elenchus recommended that, for allocating the costs of the Energy Markets department, "OPG consider using a MCR cost driver rather than OM&A/Capital for allocating costs within Renewable Generation".

At Reference 2, Elenchus recommended that OPG enhance its internal written documentation of the cost allocation model and description of its allocation processes.

Question(s):

a) Is OPG planning to implement the Elenchus recommendation to use the Maximum Continuous Rating (MCR) cost driver discussed at Reference 1? If not, please explain OPG's rationale and provide any analysis conducted to support its decision.

b) Is OPG planning to implement the Elenchus recommendation made at Reference 2? If not, please explain OPG's rationale and provide any updated internal documentation.

Response

a) Yes.

b) Yes.

Board Staff Interrogatory #218

Interrogatory

Reference:
Ref 1: Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / p. 13
Ref 2: Exhibit F3 / Tab 1 / Schedule 1 / p. 9

Preamble:

The Hackett Group (Hackett), which completed OPG's last two corporate support costs benchmarking studies, was retained by OPG again to carry out the study for this Application.

At Reference 1, Hackett identified that OPG's HR process costs increased from $3,806 per employee in 2019 to $4,742 per employee in 2024, while the peer group median is at $3,543 per employee in 2024.

At Reference 2, in discussing HR process costs remaining in the 3rd quartile, OPG refers to "intensified recruitment and onboarding efforts and other support required through a period of increased hiring and workforce transition".

Question(s):

a) Please provide a more detailed explanation regarding why OPG's HR process costs increased by almost $1,000 per employee since 2019 and why OPG is $1,200 per employee higher than the peer group median.

Response

a) Compared to 2019, HR process costs increased due to an increase in resources required to perform additional recruitment and onboarding work effort, and increased investment to automate the associated processes. These increases were necessary to meet elevated hiring requirements following a period of reducing hiring associated with the anticipated downsizing related to the end of Pickering commercial operations as planned in EB-2020-0290. As discussed at Ex. F4-3-1, pp. 11, 13-14 and Ex. F3-1-1, p. 4, the subsequent shift of the organization from downsizing to an expanded project mandate, including the refurbishment and continued operations of Pickering, resulted in a peak in hiring and onboarding needs, including an approximately 120% increase in the number of applications since 2022 and an approximately 199% increase in OPG onboarding since 2019 (refer to Ex. L-F3-SUP-013, Attachment 1).

In parallel, higher candidate decline rates (peaking at approximately 26% in 2022) required additional effort to fill positions, including expanded outreach and partnership activities aimed at improving acceptance outcomes, which resulted in an improvement of 33% in external offer decline rates by 2024. While these actions and related technology enhancements increased HR costs in the 2020-2024 period, the investments to automate and streamline recruitment and onboarding have delivered measurable efficiency gains, including a 34% reduction in the average time to fill positions (Ex. L-F3-SUP-013, Attachment 1).

The ongoing initiatives to automate and streamline the function and the expectation of a return to a comparatively lower volume of hiring between 2026-2030 contribute to the HR department's lower costs over the IR term. Based on Ex. F3-1-1, Table 1, the HR department's costs are forecast to decline from 2024 levels, in inflation adjusted terms, by approximately 13% by 2031, while absorbing the incremental needs associated with the operations of DNNP Unit 1 once it comes online (estimated using an illustrative 2.5% annual cost escalation assumption).

Society Interrogatory #013

Interrogatory

Reference:
OEB staff interrogatory F3-Staff-218

Preamble:

Hackett identified that OPG's HR process costs increased from $3,806 per employee in 2019 to $4,742 per employee in 2024, while the peer group median is at $3,543 per employee in 2024.

OEB staff have asked OPG to "provide a more detailed explanation regarding why OPG's HR process costs increased by almost $1,000 per employee since 2019 and why OPG is $1,200 per employee higher than the peer group median".

It is not clear from the submitted evidence as to whether OPG has maintained or improved or reduced its HR service levels to its internal client base of employees through the 2019 to 2024 period.

Question(s):

a) Please provide HR service level performance metrics actual annual values for its internal client base of employees for the period 2019 until 2024.

b) Please explain annual changes in these levels of +/- 5% or more as well as any changes between 2019 and 2024 of +/- 5% or more.

c) If OPG has no such performance metrics for its HR service levels to its internal client base of employees, please explain:
   i. Why there are no such performance metrics, and;
   ii. How and why notionally HR service levels to its internal client base of employees have changed between 2019 and 2024.

Response

a) Refer to Attachment 1.

   Certain metrics in Attachment 1 became available for reporting during the 2019-2024 period due to new data tracking capability. Information is provided for the years it is available.

b) The year over year changes in the metrics of +/- 5% or more as well as any changes between 2019 and 2024 of +/- 5% or more are driven by business needs as well as efforts to adopt technological advancements and to improve HR processes. The efforts resulted in an overall improvement of the metrics over the period. Refer to Ex. L-F3-SEC-172 and Ex. L-F4-Staff-218 for additional details regarding increased recruitment and employee support demand since EB-2020-0290.

c) Not applicable.

Attachment 1- Human Resources Service Metrics (2019-2024)

Line No.	Metric	2019	((c) - (a)) / (a)	2020	((e) - (c)) / (c)	2021	((g) - (e)) / (e)	2022	((i) - (g)) / (g)	2023	((k) - (i)) / (i)	2024	% Change over Period
		Actual	% Change	Actual	% Change	Actual	% Change	Actual	% Change	Actual	% Change	Actual	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Recruitment - Avg Time to Fill (Days)							69	1%	70	-34%	46	-33%
2	Recruitment - External Offer Decline Rate							26%	-35%	17%	-47%	9%	-65%
3	Recruitment - Internal Movement	1,234	22%	1,504	1%	1,521	-3%	1,480	16%	1,723	1%	1,747	42%
4	Recruitment - External Hires	140	9%	153	46%	224	214%	704	78%	1,251	23%	1,539	999%
5	Recruitment - Trade Union Hall Requisitions	257	60%	410	-26%	304	5%	320	-10%	287	-8%	263	2%
6	Recruitment - OPG Onboarding Volume	762	31%	995	8%	1,079	86%	2,007	38%	2,777	-18%	2,279	199%
7	Recruitment - OPG Vendor Onboarding Volume	699	29%	904	70%	1,536	211%	4,782	-9%	4,349	6%	4,611	560%
8	Recruitment - Outreach Events	11	-100%	0	0%	0	0%	0	n/a	35	17%	41	273%
9	Recruitment - Equity Deserving Hire Ratio							31%	0%	31%	52%	47%	52%
10	Recruitment - ION Program Placements	12	67%	20	30%	26	8%	28	11%	31	77%	55	358%
11	Employee Turnover Rates	5.40%	12%	6.00%	-23%	4.70%	29%	6.00%	-40%	3.60%	5%	3.80%	-29%
12	HR - Case Volume			64,068	-6%	59,908	5%	63,059	3%	65,008	3%	66,997	5%
13	HRSC - Avg. Case Duration in Days			94	-21%	74	-92%	6	0%	6	-33%	4	-96%
14	Number of Employee Communications	917	15%	1,059	8%	1,147	5%	1,207	34%	1,620	6%	1,712	87%
15	Employee Training Hours (Non-Tech)	57,413	-38%	35,674	113%	75,901	29%	97,744	31%	128,002	34%	171,883	199%
16	Employee Self-Development Training Hours	N/A		1,053	39%	1,466	90%	2,785	90%	5,287	154%	13,449	1177%

VECC Interrogatory #012

Interrogatory

Reference:
Exhibit F3, Tab 2, Schedule 1, Table 1

Question(s):

a) Please update Table 1 -Corporate Asset Service Fees – Regulated Hydro Electric- to include 2025 actual results.

b) In 2023 actual costs for the Kipling Ave offices et al (line 2) and OPG Corporate Headquarters (Line 3) totaled $1.1 million. In 2027 the forecast is for no allocations from Kipling Ave et al. but $4.0 million in costs of CHQ. Please explain the change occurring between 2023 and 2027.

Response

a) Refer to Attachment 1.

b) As noted at Ex. F3-2-1, p. 2, lines 11-13 beginning in the IR term, asset service fees are no longer charged for the leasehold improvements at 700 University Avenue and the Wesleyville site. The asset service fee for the 800 Kipling Avenue site was discontinued following the site's sale in 2022. The increase in the asset service for the Corporate Headquarters (CHQ) since 2023 primarily corresponds to the associated in-service additions, discussed at Ex. D2-1-2, p. 4, line 15 to p. 5, line 2.

Attachment #1

Corporate Asset Service Fees - Regulated Hydroelectric ($M)

Line No.	Business Unit	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Corporate Information Technology Assets**	2.7	3.0	3.4	4.4	3.8	4.5	5.9	5.6	5.8	6.8	8.4	8.5
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	3.2	2.9	2.5	3.5	2.3	2.2	2.0	1.1	1.3	0.7	0.3	0.0
3	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.6	3.1	4.0
4	**Joint-use Renewable Generation Assets**	0.9	1.6	1.3	1.2	2.6	3.9	5.8	8.3	8.3	9.7	9.6	12.7
5	**Total**	6.8	7.5	7.1	9.1	8.6	10.6	13.7	15.0	16.0	18.8	21.5	25.2

VECC Interrogatory #013

Interrogatory

Reference:
Exhibit F3-1-1 / Attachment 2 / Table 7b

Question(s):

a) Are the Hackett Group benchmark categories at page 2 of Attachment 2 (i.e. Finance/Procurement/Real Estate/Human Resources/ Information Technology/Executive) intended to match the similarly named six categories of corporate costs shown in the subsequent tables, e.g. Table 1-3b?

b) Please revise Table 7b to show 2025 actual results.

c) Please revise Table 7b to show the number of Staff in each of the six categories (as identified in response to a) above) for each year 2020 – 2027. For example, in 2020 allocating the 121.1 Regular Staff to each of the six categories.

Response

a) No. Refer to Ex. L-F3-CCC-081 for further details.

b) Refer to Attachment 1.

c) OPG is unable to provide the requested information for historical (2020-2023) and forecast years (2025-2031), by each of Nuclear and Regulated Hydroelectric, for the reasons provided in Ex. L-F3-CCC-081, part a).

OPG is able to provide the total regulated (Nuclear and Regulated Hydroelectric) FTEs in the categories that underlie the 2024 Hackett Corporate Benchmarking Study costs. Such total regulated FTEs by corporate group are set out in Chart 1 below.

1

Chart 1 – Total Regulated FTEs by Corporate Group in Corporate Cost Benchmarking Study, Shown by Hackett Grouping	
Corporate Group	**2024 Benchmarked FTEs**
Corporate & Technology Services (CTS) / Information Technology	333.4
Real Estate	28.8
Supply Chain / Procurement	135.0
Finance	147.5
Human Resources	237.7
Corporate Centre / Executive & Corporate Service (ECS)	125.5
Total Benchmarked FTEs	**1,007.9**

2

Attachment #1

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - Regulated Hydroelectric - 2020-2027

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Hydroelectric OM&A:								
1	**Regular Staff**	121.1	105.0	117.9	130.0	153.1	146.7	155.6	147.4
	Non-Regular Staff								
2	Temporary	10.5	12.7	15.1	14.2	13.7	12.1	8.4	6.2
3	**Subtotal Regulated Hydroelectric OM&A**	131.6	117.6	133.0	144.3	166.8	158.7	164.0	153.6
	Hydroelectric Capital:								
4	**Regular Staff**	6.3	7.6	10.0	10.0	11.5	17.4	29.9	36.4
	Non-Regular Staff								
5	Temporary	0.1	0.1	0.0	0.9	0.7	0.4	0.0	0.4
6	**Subtotal Regulated Hydroelectric Capital**	6.4	7.7	10.0	10.9	12.2	17.9	29.9	36.8
7	**Total Regulated Hydroelectric**	137.9	125.4	143.0	155.1	179.0	176.6	193.9	190.3

VECC Interrogatory #014

Interrogatory

Reference:
Exhibit F3-1-1 Table 8

Question(s):

a) Please revise Table 8 to show 2025 actual results.

b) Please revise Table 8 in the same fashion as the previous question, showing the Staff allocated to each of the six categories. For this revision the years 2023 through 2027 are the only years we are requesting the revision to show.

Response

a) Refer to Attachment 1. Note certain amounts in this version of Ex. F3-1-1, Table 8 have been corrected in line with Ex. L-F2-Staff-199, Attachment 1.

b) Refer to Ex. L-F3-VECC-013.

Attachment #1

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Nuclear OM&A:												
1	**Regular Staff**	854.9	799.2	880.2	1,049.6	1,124.5	1,050.5	1,077.1	998.1	993.1	996.0	1,003.0	1,055.3
	Non-Regular Staff												
2	Term/ETE/PECO Temporary	57.4	76.1	79.2	61.9	53.0	39.9	33.3					
3	Temporary	146.9	156.0	168.5	186.2	152.1	118.1	73.4	55.4	55.5	53.2	54.9	58.0
4	EPSCA	24.6	25.3	22.1	21.6	15.7	18.4	28.1	23.1	23.1	23.1	23.0	26.9
5	**Total Non-Regular Staff**	229.0	257.3	269.8	269.7	220.8	176.4	134.7	78.5	78.5	76.2	78.0	85.0
6	**Subtotal Nuclear OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,226.9	1,211.8	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
	Nuclear Capital:												
7	**Regular Staff**	14.7	14.2	21.5	42.5	45.5	65.4	116.3	155.7	153.1	156.0	152.0	144.5
	Non-Regular Staff												
8	Term/ETE/PECO Temporary	2.6	1.3	1.1	2.7	5.6	3.1	0.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	1.0	0.0	0.0	10.8	11.1	0.0		3.2	3.2	3.2	3.2	3.2
10	EPSCA	10.7	10.2	1.0	2.8	1.7	1.4	0.9	0.9	0.9	0.9	0.9	0.9
11	**Total Non-Regular Staff**	14.3	11.5	2.1	16.3	18.4	4.5	0.9	4.1	4.1	4.1	4.1	4.2
12	**Subtotal Nuclear Capital**	29.0	25.7	23.6	58.8	63.9	69.9	117.2	159.8	157.2	160.1	156.1	148.6
	Darlington Refurbishment:												
13	**Regular Staff**	37.4	33.4	31.5	32.4	37.3	27.3	17.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
14	Temporary	10.6	12.2	9.3	10.2	6.9	7.6	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	6.7	8.9	7.8	7.2	8.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Non-Regular Staff**	17.3	21.1	17.2	17.4	14.9	14.3	0.0	0.0	0.0	0.0	0.0	0.0
17	**Subtotal Darlington Refurbishment**	54.7	54.5	48.7	49.9	52.2	41.6	17.0	0.0	0.0	0.0	0.0	0.0
	Pickering Refurbishment:												
18	**Regular Staff**	0.0	0.0	0.0	0.9	29.7	92.6	145.7	244.4	234.9	234.9	229.1	167.9
	Non-Regular Staff												
19	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Temporary	0.0	0.0	0.0	0.0	4.4	8.3	1.0	3.0	1.0	1.0	1.0	1.0
21	EPSCA	0.0	0.0	0.0	0.0	4.5	2.9	8.0	13.0	13.0	13.0	13.0	10.3
22	**Total Non-Regular Staff**	0.0	0.0	0.0	0.0	11.0	11.2	9.0	16.0	14.0	14.0	14.0	11.3
23	**Subtotal Pickering Refurbishment**	0.0	0.0	0.0	0.9	40.7	103.9	154.7	260.4	248.9	248.9	243.1	179.2
	Darlington New Nuclear Program:												
24	**Regular Staff**	0.0	0.0	9.9	14.0	21.9	28.2	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
25	Temporary	0.0	0.0	0.2	0.3	1.7	6.5	0.0	0.0	0.0	0.0	0.0	0.0
26	EPSCA	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total Non-Regular Staff**	0.0	0.0	0.2	0.3	1.8	6.6	0.0	0.0	0.0	0.0	0.0	0.0
28	**Subtotal New Nuclear DN Capital**	0.0	0.0	10.2	14.2	23.7	34.8	0.0	0.0	0.0	0.0	0.0	0.0
	Darlington New Nuclear & Other New Nuclear OM&A:												
29	**Regular Staff**	4.8	25.4	0.3	4.6	7.6	14.0	41.8	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
30	Temporary	0.4	2.1	0.0	0.2	0.3	1.5	1.0	0.0	0.0	0.0	0.0	0.0
31	**Subtotal Darlington & Other New Nuclear OM&A**	5.2	27.6	0.3	4.9	7.8	15.5	42.8	0.0	0.0	0.0	0.0	0.0
	Nuclear Provision:												
32	**Regular Staff**	16.3	14.5	16.1	15.3	27.6	52.4	59.1	58.1	56.5	49.1	50.2	50.4
	Non-Regular Staff												
33	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0
34	Temporary	1.5	0.5	2.0	2.4	2.5	1.2	1.0	1.0	1.0	1.0	1.0	1.0
35	EPSCA	0.0	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0
36	**Total Non-Regular Staff**	2.1	1.6	2.0	2.4	4.4	2.5	1.0	1.0	1.0	1.0	1.0	1.0
37	**Subtotal Nuclear Provision**	18.4	16.1	18.1	17.8	31.9	54.9	60.1	59.1	57.5	50.1	51.2	51.4
38	**Total Nuclear**	1,191.3	1,180.5	1,250.8	1,465.6	1,565.7	1,547.4	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4

AMPCO Interrogatory #108

Interrogatory

Reference:
F4-1-1 Table 1

Question(s):

Please provide the OEB-approved depreciation and amortization amounts for each of the years 2016 to 2024.

Response

Per the OEB's Filing Requirements, the phrase "OEB-approved" refers to the set of data used by the OEB as the basis for approving the payment amounts.[1] Because OPG has not rebased its regulated hydroelectric payment amounts since EB-2013-0321, there are no historical OEB-approved amounts for the years in question.

[1] Ontario Energy Board, *Filing Requirements for Ontario Power Generation Inc.*, September 17, 2024, p. 6.

AMPCO Interrogatory #109

Interrogatory

Reference:
F4-1-1 Table 2

Question(s):

Please provide the OEB-approved depreciation and amortization amounts for the Nuclear Facilities for each of the years 2020 to 2024.

Response

Chart 1 below provides the OEB-approved depreciation and amortization amounts for OPG's nuclear facilities for the years 2020 to 2024.

Chart 1 – OEB-Approved Depreciation and Amortization Amounts for OPG's Nuclear Facilities ($M)

	2020	2021	2022	2023	2024
OEB-approved Depreciation & Amortization[1]	575.1	286.0	547.2	462.9	567.4

[1] The 2020 and 2021 amounts are per EB-2016-0152 Payment Amounts Order, App. A, Table 10, col. (b), lines 40 and 50, respectively. The 2022-2024 amounts are per EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 9, 18 and 27.

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

AMPCO Interrogatory #112

Interrogatory

Reference:
F4-3-1 Attachment 1 p.1

Question(s):

Please provide Appendix 2-K on a Plan basis (EB-2020-0290) for each of the years 2020 -2031 and include the adjustments requested in F4-AMPCO-110 part (b) to part (d).

Response

Refer to EB-2020-0290, Ex. JT 4.8 for 2020-2026. Refer to Ex. L-F4-AMPCO-110 for 2027-2031.

AMPCO Interrogatory #117

Interrogatory

Reference:
F4-3-1 Attachment 1

Question(s):

a) Please provide Appendix 2-K for Darlington NGS that includes the adjustments in F4-AMPCO-110 part (b) to part (d) and provide an excel version of the response.

b) Please provide Appendix 2-k for Pickering NGS that includes the adjustments in F4-AMPCO-110 parts (b) to part (d) and provide an excel version of the response.

Response

a) and b)

Refer to Attachment 1, including the adjustments requested in Ex. L-F4-AMPCO-110 parts b) and d). Regarding the adjustments requested for Ex. L-F4-AMPCO-110 part c), refer to Ex. L-F4-AMPCO-110 part c).

AMPCO Interrogatory #118

Interrogatory

Reference:
F4-3-1

Question(s):

Please provide the incremental compensations costs due to hiring a Term Employee as a Regular Employee and show the calculation.

Response

As discussed in EB-2020-0290, Ex. F4-3-1, p.7, lines 19-23, the main difference in the compensation costs of a PWU-represented Term Employee and a PWU-repersented Regular Employee results from a Term Employee not being eligible to join OPG's pension and benefit plans. The resulting difference in annual compensation costs (which, for pension and OPEB, comprise the current service cost components) for a newly hired employee is estimated at approximately $35,000, reflecting the pension and OPEB impacts computed by OPG's external actuary, Aon, based on the actuarial assumptions underpinning the forecast costs in this Application.

Aon produced the pension and OPEB estimate using their proprietary actuarial valuation system, using demographic and economic assumptions and projection algorithms that cannot be replicated in this response. The figures provided reflect the output of this system, which is the same used by Aon for OPG's pension and OPEB related reporting in its consolidated financial statements.

AMPCO Interrogatory #119

Interrogatory

Reference:
F4-3-1

Question(s):

a) Please provide the number of forecast and actual layoffs and the associated forecast and actual severance costs for the period 2022-2026 period.

b) Please provide the assumption with respect to severance costs for 2027-2031.

c) Please provide the employee turnover rate for each of the years 2020 to 2025.

d) Please quantify ($) the assumptions in the 2027-2031 budget with respect to total annual merit increases to be paid out.

e) Please provide the merit increases paid in total over the 2020 to 2025 period.

f) Please provide the reduction ($) because of the actual vacancy rate for each of the years 2022 to 2025.

g) Please provide OPG's assumptions with respect to the vacancy rate for each of the years 2027 to 2031.

Response

a) There were no actual layoffs for the 2022-2025 period, none are forecast for 2026, and as such there are no associated severance costs.

b) OPG has not included any severance costs in its proposed revenue requirements for the 2027-2031 IR term.

c) The Regular employee voluntary turnover rate, referring to the percentage of employees that leave due to retirements and resignations over a period and are replaced, is provided in Chart 1.

Chart 1 – Regular Employee Annual Voluntary Turnover Rates

2020	2021	2022	2023	2024	2025
6.0%	4.7%	6.1%	3.6%	3.8%	3.8%

d) Refer to Ex. L-F4-CCC-085, part f).

e) The management merit increases attributable to the regulated business over the 2020-2025 period, as estimated to the regulated operations, are outlined in Chart 2 below:

Chart 2 – Annual Total Management Merit Increases Attributable to the Regulated Business ($M)

2020	2021	2022	2023	2024	2025
2.5	2.1	2.3	4.1	5.8	7.1

f) OPG does not track vacancy rates. OPG's 2025-2031 Business Plan was created based on the work programs and the need to execute them; therefore, any vacancy would require other resources to execute the work. With respect to the historical period, actual FTEs, in aggregate, exceeded the levels forecasted in EB-2020-0290. As such, there are no savings associated with vacancies.

g) OPG did not include any assumptions with respect to a vacancy rate in its 2025-2031 Business Plan. The FTEs in the plan are based on the required resource levels to execute and support planned work programs.

AMPCO Interrogatory #120

Interrogatory

Reference:
F4-3-1 p.25

Preamble:

Chart 1 provides the 2021-2026 Collective Agreement Wage Increases for PWU and Society for the years 2021 to 2026.

Question(s):

a) Please provide the wage increase assumptions built into the plan for the years 2027 to 2031 for PWU and Society.

b) Please provide the average wage increase for management for each of the years 2021 to 2031.

Response

a) Refer to Ex. L-F4-Staff-227, Chart 1.

b) The wage increase assumptions for management for the 2027-2031 period are detailed in Ex. L-F4-Staff-227, Chart 1.

Chart 1 below provides the average wage increase for management for each of the years 2021-2026. As detailed in Ex. F4-3-1, p. 30, line 19, wage increases for management are determined through performance-based merit increase budgets. On an annual basis, OPG submits the merit budget for management to its Board of Directors for approval.

Chart 1 – Average Merit Increase for Management (2021-2026)

2021	2022	2023	2024	2025	2026
1.57%	1.75%	2.89%	3.35%	3.63%	3.11%

AMPCO Interrogatory #121

Interrogatory

Reference:
F4-3-1 p.27

Question(s):

With respect to Figures 5, 6, 7, 8 please provide the underlying data.

Response

The data in the referenced figures was compiled using the applicable publicly available collective agreements (available through the Ontario Labour Relations Board at https://www.lr.labour.gov.on.ca/en-CA/Collective-Agreements/). Refer to Ex. L-F4-Staff-230 for the referenced figures, including the underlying data.

AMPCO Interrogatory #123

Interrogatory

Reference:
F4-04-1 Table 3

Question(s):

a) Please explain the increase in Performance Incentive costs in 2025.

b) Please provide the derivation of the Performance Incentive amounts ($M) for each of the years 2027 to 2031.

Response

a) As discussed in Ex. F4-3-1, pp. 30-31, the Applicants use a financial results model for its Stakeholder Return Program ("SRP"), whereby forecasted earnings before tax and corporate balanced scorecard results are key components in determining performance incentive amounts. The increase in performance incentive costs in 2025 compared to 2024 is due to a higher forecast EBT in that year. OPG seeks approval from its Board of Directors for the percentage applied to forecast EBT for any given program year. As discussed in Ex. L-F4-SEC-195, the percentage applied is limited to an industry range provided by Willis Towers Watson, and has been at the lowest end of this range.

b) Chart 1 below provides a derivation of the forecast total OPG performance incentive amounts for each of the years 2027-2031, as presented in Ex. F4-4-1, Table 1, line 4. As noted at Ex. F4-4-1, p. 7, lines 12-14, these total OPG performance incentive costs are attributed, as applicable, to OPG's regulated hydroelectric facilities (Ex. F4-4-1, Table 2, line 3), OPG's nuclear facilities (Ex. F4-4-1, Table 3, line 4) and the DNNP facilities (Ex. F4-4-1, Table 4, line 4), pursuant to OPG's cost allocation methodology.

As shown in Chart 1, the total performance incentive costs are based on a corporate score at target, or 1.0, in the forecast period.

Chart 1 – Calculation of Total OPG Performance Incentive Costs* ($M)

	2027	2028	2029	2030	2031
Forecast Earnings Before Tax [A]					
% of Earnings Before Tax [B]					
Calculation with an assumed Corporate Score of 1.0 (Target) [C] = [A] x [B] x 1.0	41.7	44.8	46.5	47.0	48.4
Adjustment for Individual Performance Distribution Curve of 2.65% [D] = [C] x 2.65%	1.1	1.2	1.2	1.2	1.3
Allowance for CEO Awarded Amounts for Performance Achievement, up to 10% [E] = [C+D] x 10%	4.3	4.6	4.8	4.8	5.0
Total Performance Incentive Cost [C+D+E]	**47.0**	**50.6**	**52.5**	**53.1**	**54.6**

*numbers may not calculate due to rounding

1

AMPCO Interrogatory #124

Interrogatory

Reference:
F4-04-1

Preamble:

The budget for the program is set using a financial results model based on a percentage applied to forecast corporate earnings before tax. Between 2021-2024, 2% was applied on average to forecast EBT and OPG's corporate score ranged from 0.97 to 1.28.

Question(s):

a) Please provide the percentage applied to forecast corporate earnings before tax in 2025 and 2026.

b) Please provide the corporate score in 2025 and show how it was calculated.

c) Please provide the assumptions in the Plan with respect to the percentage applied to forecast corporate earnings before tax for the years 2027 to 2031 for Nuclear. Please confirm the percentages apply to both Nuclear and Hydroelectric. If not please provide separately.

Response

a) Refer to Ex. L-F4-SEC-195.

b) Refer to Attachment 1.

c) Refer to Ex. L-F4-AMPCO-123.

2025 Corporate Balanced Scorecard						2025 Year End Results		
Weight	**Key Performance Indicators**		**Threshold**	**Target**	**Stretch**	**Year-end Result**	**Year-end Weighted Score**	**Year-end Assessment**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce.							
10%	**Safety: Serious Injury Incidence Rate (SIIR)**		0.04	0.02	0	**0.00**	**1.000**	**Stretch (adjusted to Target)**
10%	5%	**Supply Chain Diversity Program ($M)**	$45	$55	$70	**$103**	**1.500**	**Stretch**
	5%	**Indigenous Economic Empowerment ($M)**	$75	$100	$125	**$241**	**1.500**	**Stretch**
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)		$2,171	$2,311	$2,656	**$2,536**	**1.326**	**Above Target**
15%	**OM&A Expenses From Ongoing Operations** – Total OPG ($M)		$2,753	$2,703	$2,558	**$2,689**	**1.048**	**Above Target**
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)		69.3	71.8	74.3	**72.3**	**1.100**	**Above Target**
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
15%	7.5%	**Refurbishment Cost** – Unit 3,1 & 4 Costs ($M)	N/A	$6,216	$6,073	**$6,005**	**1.500**	**Stretch**
	7.5%	**Refurbishment Schedule –** Unit 4 Schedule - % Complete	Project is 86% complete overall	Project is 91% complete overall	Project is 95% complete overall	**98%**	**1.500**	**Stretch**
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g., Darlington Refurbishment)		$1,126 +/- 10% to +/- 15%	$1,126 +/- 3% to +/- 10 %	$1,126 +/-3%	**$1,196**	**1.000**	**Target**
100%	**Year-end Result**						**1.218**	

These measures form the basis on which OPG's overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute.

*The Board will include OPG's reputation risk and Environmental, Social, and Governance (ESG) considerations as part of its assessment of Corporate performance. The Board and President reserve the right to determine the Corporate Score.
In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

AMPCO Interrogatory #127

Interrogatory

Reference:
F4-3-1 Attachment 1

Question(s):

For the purposes of Attachment 1, please define FTE and confirm at what point in the year the FTEs numbers are based on.

Response

An FTE is not determined at a point in time but rather is a calculation based on annual hours.

The FTE calculations and associated costs are consistently represented in the Application for the historical and forecast period as the number of hours worked over the year converted to an equivalent number of full-time employees. The associated labour costs are determined on the basis of the number of hours worked. Historical FTEs are calculated by dividing the total period of time an employee occupied a position during the year by the scheduled hours associated with the position. The same scheduled hours are utilized whether an employee is a regular full time, regular part time or a non-regular employee. The standard scheduled hours of work are either 35, 37.5 or 40 hours per week.

For example, a part time regular employee who works on average 20 hours per week in a position normally scheduled for 40 hours, would equate to 0.5 of an FTE, provided the employee worked the entire year. Similarly, a full time regular or non-regular employee in this same position working 40 hours a week for half of the year would also equate to 0.5 of an FTE.

Forecast FTEs are determined as part of the business planning process in a manner similar to that described above. Demand for labour resources are identified and hours assigned to different work programs by job family. There are standard scheduled hours of work for each job family, being 35, 37.5 or 40 hours per week. The hours assigned to the various work programs and the standard scheduled hours of work are used to derive the number of FTEs forecasted for each job family. In some cases, forecasted FTEs may be entered directly. In these situations, the associated hours are determined using the scheduled hours of work for the job family.

CCC Interrogatory #086

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 1

Question(s):

Please provide a revised version of Appendix 2-K for the Nuclear Facilities (excluding DNNP LP) that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i) to iii)

Refer to Ex. L-F4-AMPCO-110, Attachment 1.

CCC Interrogatory #089

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachments 1-3

Question(s):

Please provide a revised version of Appendix 2-K for the combined regulated business (i.e., all of Nuclear, DNNP LP, and Hydroelectric FTEs and compensation combined) that has all the same information as in the pre-filed Appendix 2-K and also includes:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i. ii. and iii.

Refer to Attachment 1.

Regulated - OM&A

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k") EB-2025-0297 (2027-2031 Custom IR term)

Numbers may not add due to rounding

Line No.	Regulated Facilities	Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
		2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	5.9	6.7	6.3	6.1	31.3	25.3	28.0	30.0	33.3	32.3	32.3	31.9	28.6	28.6	28.7	28.0	32.2
2	Non-Executive Management	77.5	77.7	78.4	72.9	523.6	425.1	407.8	458.4	493.7	471.7	469.6	464.2	389.1	377.8	377.5	380.4	426.4
3	Management Subtotal	83.4	84.4	84.8	79.1	554.9	450.5	435.8	488.4	527.0	504.0	501.9	496.1	417.7	406.4	406.1	408.4	458.6
4	Society	241.0	247.5	276.4	260.9	1,993.1	1,836.6	1,697.1	1,789.9	1,888.1	1,753.2	1,844.4	1,804.4	1,350.2	1,324.0	1,325.6	1,362.4	1,558.6
5	PWU	646.9	613.9	635.1	618.7	3,693.3	3,514.2	3,056.5	3,089.5	3,270.2	3,168.9	3,329.0	3,291.4	2,794.4	2,793.9	2,844.4	2,845.3	3,255.6
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	586.2	767.0	887.8	930.0	600.5	237.9	202.2	174.7	0.0	0.0	0.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	77.3	94.4	99.4	88.2	100.0	51.5	54.2	25.4	22.0	21.6	21.6	21.0	20.0
8	Subtotal	971.3	945.9	996.3	958.7	6,904.8	6,662.7	6,176.6	6,385.9	6,385.8	5,715.5	5,931.6	5,792.1	4,584.2	4,546.0	4,597.8	4,637.3	5,292.7
	OPG Regulated - Allocated																	
9	Executive	6.3	4.8	3.6	3.3	27.1	25.3	26.8	28.4	27.4	29.5	30.4	33.5	31.3	31.2	31.1	30.6	28.7
10	Non-Executive Management	61.3	56.8	55.4	56.7	289.3	281.5	286.0	325.5	352.5	347.4	395.7	398.5	358.1	358.9	358.0	360.0	358.7
11	Management Subtotal	67.7	61.6	59.1	60.1	316.5	306.7	312.8	353.9	380.0	376.9	426.1	432.0	389.4	390.1	389.1	390.7	387.4
12	Society	72.2	67.9	74.6	77.0	407.4	396.6	419.2	548.3	601.1	570.6	619.2	598.6	534.3	537.1	530.0	536.3	560.3
13	PWU	37.3	38.8	39.3	34.0	427.9	397.4	451.0	482.7	470.3	395.3	420.0	386.0	357.8	354.7	353.0	354.2	388.1
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	57.6	76.1	79.2	61.9	53.0	39.9	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	24.7	25.3	22.1	21.6	15.7	18.4	27.1	28.1	23.1	23.1	23.1	23.1	27.1
16	Subtotal	177.1	168.4	172.9	171.1	1,234.1	1,202.1	1,284.3	1,468.4	1,520.0	1,401.1	1,531.4	1,477.9	1,304.6	1,305.0	1,295.2	1,304.3	1,362.9
	OPG Regulated Facilities																	
17	Executive	12.2	11.5	9.9	9.5	58.4	50.6	54.8	58.3	60.7	61.8	62.7	65.5	59.8	59.8	59.7	58.7	60.8
18	Non-Executive Management	138.8	134.6	133.9	129.6	812.9	706.6	693.8	783.9	846.2	819.1	865.2	862.7	747.2	736.7	735.5	740.4	785.1
19	Management Subtotal	151.0	146.1	143.8	139.1	871.3	757.2	748.6	842.2	907.0	880.9	927.9	928.2	807.0	796.5	795.2	799.1	845.9
20	Society	313.2	315.5	351.0	337.9	2,400.4	2,233.3	2,116.2	2,338.3	2,489.1	2,323.8	2,463.6	2,403.0	1,884.4	1,861.2	1,855.6	1,898.7	2,118.9
21	PWU	684.2	652.7	674.4	652.7	4,121.2	3,911.6	3,507.5	3,572.1	3,740.5	3,564.2	3,749.0	3,677.4	3,152.3	3,148.7	3,197.4	3,199.6	3,643.8
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	643.9	843.1	967.1	991.9	653.4	277.8	241.2	208.0	0.0	0.0	0.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	102.0	119.7	121.5	109.8	115.7	69.9	81.3	53.5	45.1	44.7	44.7	44.1	47.1
24	Total	1,148.5	1,114.3	1,169.2	1,129.8	8,138.8	7,864.8	7,461.0	7,854.3	7,905.7	7,116.6	7,463.0	7,270.0	5,888.8	5,851.0	5,892.9	5,941.5	6,655.7
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	3.0	3.2	2.8	2.5	15.1	13.6	14.4	14.1	16.0	17.8	16.2	17.2	16.1	16.3	16.7	16.6	17.6
26	Non-Executive Management	18.5	18.1	18.6	18.5	116.0	102.1	108.0	119.4	131.3	138.5	140.2	145.7	132.1	133.3	137.5	143.0	156.3
27	Management Subtotal	21.5	21.3	21.4	21.0	131.1	115.6	122.4	133.5	147.3	156.3	156.4	162.9	148.1	149.6	154.2	159.7	173.9
28	Society	37.8	39.0	42.8	42.2	316.3	319.8	291.0	353.8	380.3	366.5	395.7	393.5	324.8	328.0	338.4	360.8	418.4
29	PWU[2]	73.7	69.3	70.1	69.9	478.7	489.2	418.1	495.6	577.2	497.5	496.1	507.9	453.3	465.2	493.4	509.7	603.8
30	Term[2]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	69.3	95.0	114.9	130.9	84.3	37.2	26.8	24.3	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	14.9	17.1	13.8	11.5	15.7	15.8	12.8	8.8	8.0	8.1	8.5	8.4	9.1
32	Unallocated[3]	(5.1)	(4.9)	(11.7)	(11.0)	(11.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	127.9	124.7	122.5	122.1	998.9	1,036.7	960.2	1,125.2	1,204.8	1,073.4	1,087.8	1,097.5	934.2	950.9	994.4	1,038.6	1,205.3
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.8	1.0	1.1	1.0	7.9	6.8	7.0	9.1	7.7	9.8	8.8	8.5	8.9	9.6	9.9	9.9	10.4
35	Non-Executive Management	2.3	3.1	2.9	2.8	23.0	23.2	20.9	32.0	32.9	40.7	36.1	33.3	34.8	37.4	38.9	39.6	40.6
36	Management Subtotal	3.1	4.1	4.0	3.8	30.9	30.0	27.9	41.1	40.6	50.4	44.9	41.9	43.7	47.0	48.8	49.6	51.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.4	0.8	1.8	0.9	5.5	5.8	5.6	5.7	6.3	6.7	3.2	3.0	2.9	2.9	2.4	2.3	2.2
38	PWU	0.0	1.2	2.4	1.9	12.4	14.2	14.5	14.9	15.0	18.4	8.5	8.0	7.8	7.6	6.9	6.6	1.6
39	Total	0.4	2.0	4.3	2.8	17.9	20.0	20.1	20.7	21.3	25.1	11.7	11.0	10.7	10.5	9.3	8.9	3.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	1.9	2.4	2.4	2.8	34.3	38.5	40.3	40.3	40.2	28.9	27.8	26.2	24.1	21.2	24.7	23.6	27.5
41	PWU	5.5	7.6	7.7	8.4	75.4	83.7	72.7	82.9	92.1	68.1	71.6	66.9	73.8	64.9	77.0	70.5	83.5
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	8.7	11.3	15.6	19.9	11.2	3.9	3.1	2.5	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	1.5	2.8	3.8	3.7	5.0	1.9	0.9	0.6	1.0	0.8	0.9	0.8	0.7
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	7.3	10.0	10.1	11.2	119.8	136.2	132.4	146.9	148.5	102.7	103.4	96.2	98.8	87.0	102.6	95.0	111.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	1.2	1.3	1.1	1.0	6.7	7.8	7.8	4.9	6.0	6.4	5.8	6.7	6.1	6.2	6.4	6.4	6.8
47	Non-Executive Management	8.1	7.9	9.5	8.8	59.0	60.6	60.1	32.6	53.7	52.7	48.2	55.3	48.9	49.0	51.2	52.7	58.0
48	Management Subtotal	9.3	9.1	10.6	9.9	65.7	68.4	67.9	37.5	59.7	59.2	54.1	62.0	55.0	55.2	57.7	59.1	64.8
49	Society	16.6	16.7	21.6	20.2	158.9	178.0	168.7	88.8	155.5	131.1	134.1	149.5	116.0	117.6	123.9	131.6	156.1
50	PWU	31.0	29.6	34.1	32.1	215.1	234.8	206.9	127.6	201.4	189.5	167.5	182.5	160.8	163.9	174.5	181.9	220.6
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	5.0	5.8	8.0	8.8	7.1	2.8	1.7	1.5	0.0	0.0	0.0	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	1.0	0.2	0.3	(0.3)	(0.3)	1.3	0.6	0.4	0.4	0.4	0.4	0.4	0.4
53	Unallocated[3]	(1.0)	(1.4)	(3.0)	(1.8)	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	55.9	54.0	63.4	60.4	449.1	487.2	451.8	262.4	423.3	383.9	357.9	395.9	332.3	337.1	356.5	373.0	441.9
55	Current Benefits (Statutory)	8.3	8.3	8.1	7.9	63.5	61.1	64.8	69.2	76.7	70.7	77.5	77.1	66.0	66.7	71.6	72.5	84.3
56	Current Benefits (Non-Statutory)	5.7	6.5	5.9	5.9	38.2	48.9	46.8	48.3	46.4	56.2	53.4	53.5	46.7	48.0	50.6	52.2	61.0
57	Pension & OPEB (Current Service)[1]	41.9	39.2	49.4	46.6	347.3	377.2	340.1	144.9	300.3	257.1	226.9	265.4	219.5	222.3	234.3	248.3	296.6
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	5.0	5.5	5.0	4.5	29.7	28.2	29.2	28.1	29.8	34.0	30.8	32.5	31.1	32.1	33.1	32.9	34.8
59	Non-Executive Management	28.9	29.0	31.0	30.1	198.0	185.9	189.1	184.0	217.9	231.9	224.5	234.3	215.8	219.7	227.6	235.4	254.9
60	Management Subtotal	33.9	34.5	35.9	34.7	227.8	214.0	218.3	212.1	247.6	265.9	255.3	266.8	246.9	251.9	260.7	268.3	289.7
61	Society	56.6	58.8	68.7	66.1	514.9	542.0	505.7	488.7	582.2	533.2	560.7	572.1	467.8	469.6	489.4	518.4	604.1
62	PWU	110.2	107.7	114.3	112.3	781.7	821.9	712.1	721.1	885.8	773.6	743.7	765.2	695.6	701.6	751.8	768.7	909.6
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	82.9	112.0	138.5	159.5	102.7	43.8	31.6	28.4	0.0	0.0	0.0	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	17.4	20.1	17.9	14.9	20.3	19.0	14.3	9.9	9.3	9.3	9.8	9.6	10.3
65	Unallocated[3]	(6.1)	(6.3)	(14.7)	(12.8)	(8.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	194.6	194.8	204.2	200.2	1,616.5	1,710.1	1,592.5	1,596.3	1,838.6	1,635.6	1,605.7	1,642.4	1,419.7	1,432.4	1,511.6	1,565.1	1,813.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Regulated - CAPITAL

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

		Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
Line No.	Regulated Facilities	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	0.0	0.0	0.0	0.0	6.9	7.2	6.4	6.2	10.2	13.1	16.0	14.4	13.2	11.9	10.4	9.7	9.3
2	Non-Executive Management	1.2	2.1	2.7	5.0	123.6	114.7	135.9	151.3	227.5	290.9	380.8	343.0	373.4	360.3	343.9	322.0	283.1
3	Management Subtotal	1.2	2.1	2.7	5.0	130.5	121.9	142.2	157.5	237.7	304.0	396.8	357.4	386.6	372.2	354.3	331.7	292.3
4	Society	24.7	34.8	44.4	63.5	477.4	520.0	537.9	616.3	793.3	1,036.4	1,445.4	1,391.1	1,674.3	1,606.5	1,568.0	1,501.2	1,272.0
5	PWU	18.1	25.1	35.3	45.9	247.5	257.1	284.6	289.3	356.4	446.7	578.2	796.6	1,427.4	1,503.6	1,546.7	1,466.4	1,034.3
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	4.9	11.7	20.0	25.7	25.9	17.1	29.0	38.3	7.0	7.0	7.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	154.1	256.9	297.7	342.5	317.0	280.9	263.7	167.2	372.6	491.2	426.8	342.0	259.9
8	Subtotal	44.1	62.0	82.4	114.4	1,014.4	1,167.6	1,282.3	1,431.2	1,730.3	2,085.2	2,713.1	2,750.6	3,867.9	3,980.5	3,902.7	3,641.3	2,858.5
	OPG Regulated - Allocated																	
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	0.0	0.7	0.7	0.7	7.9	9.5	13.3	16.0	26.9	39.4	40.2	46.7	51.3	48.0	42.0	38.2	27.5
11	Management Subtotal	0.0	0.7	0.7	0.7	7.9	9.6	13.3	16.0	26.9	39.4	40.2	46.7	51.3	48.0	42.0	38.2	27.5
12	Society	1.8	1.8	2.6	4.5	37.3	41.7	51.7	79.0	112.8	155.9	202.1	212.3	278.2	264.4	256.6	246.3	207.0
13	PWU	0.0	0.0	0.1	0.1	14.6	16.0	16.4	26.9	31.2	58.5	79.5	91.3	156.4	155.7	157.2	151.9	126.3
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	2.4	1.3	1.1	2.7	7.7	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	17.4	19.1	8.9	10.0	14.3	11.1	9.9	8.9	13.9	13.9	13.9	13.9	11.2
16	Subtotal	1.8	2.4	3.3	5.2	79.6	87.6	91.4	134.6	192.8	268.0	331.7	359.3	499.8	482.1	469.6	450.3	372.0
	OPG Regulated Facilities																	
17	Executive	0.0	0.0	0.0	0.0	6.9	7.3	6.4	6.2	10.2	13.1	16.0	14.4	13.2	11.9	10.4	9.7	9.3
18	Non-Executive Management	1.2	2.8	3.3	5.7	131.5	124.2	149.2	167.3	254.3	330.3	421.0	389.7	424.7	408.3	385.9	360.1	310.5
19	Management Subtotal	1.2	2.8	3.3	5.7	138.4	131.5	155.5	173.5	264.5	343.4	437.0	404.1	437.9	420.2	396.2	369.9	319.8
20	Society	26.5	36.6	47.0	68.0	514.7	561.7	589.6	695.3	906.1	1,192.3	1,647.5	1,603.5	1,952.5	1,871.0	1,824.5	1,747.6	1,479.0
21	PWU	18.1	25.1	35.4	46.0	262.0	273.1	301.0	316.2	387.6	505.3	657.7	888.0	1,583.9	1,659.3	1,703.9	1,618.3	1,160.6
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	7.3	13.1	21.1	28.3	33.6	20.2	29.0	38.3	7.0	7.0	7.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	171.6	275.9	306.6	352.5	331.3	292.0	273.6	176.1	386.5	505.1	440.7	355.9	271.1
24	Total	45.9	64.5	85.7	119.6	1,094.0	1,255.2	1,373.7	1,565.9	1,923.1	2,353.2	3,044.9	3,109.9	4,367.7	4,462.6	4,372.3	4,091.7	3,230.5
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.0	0.0	0.0	0.0	2.2	1.9	1.5	1.6	2.6	3.2	3.9	3.7	3.5	3.2	2.9	2.7	2.7
26	Non-Executive Management	0.2	0.4	0.5	0.9	20.0	17.9	22.5	25.8	40.3	53.6	68.3	65.8	75.1	74.9	74.1	69.5	60.9
27	Management Subtotal	0.2	0.4	0.5	0.9	22.2	19.8	24.1	27.4	42.9	56.9	72.1	69.5	78.6	78.1	77.0	72.2	63.5
28	Society	3.3	4.6	5.8	8.6	64.7	75.1	81.5	103.2	134.4	181.2	241.8	242.2	315.6	315.0	325.0	316.8	276.2
29	PWU[2]	2.1	3.0	4.1	5.4	28.3	38.4	42.1	40.1	51.3	64.9	83.9	122.0	227.8	247.8	267.6	257.5	186.4
30	Term[3]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.5	1.8	2.7	4.1	4.6	1.8	4.4	5.4	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	25.9	47.0	55.3	68.7	66.3	51.7	45.2	29.9	71.5	93.7	86.0	71.3	56.1
32	Unallocated[3]	1.8	2.6	3.7	4.4	29.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	7.3	10.6	14.1	19.3	171.0	182.1	205.7	243.6	299.5	356.5	447.4	469.0	694.7	735.7	756.8	717.8	582.2
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	0.4	0.7	1.0	1.4	7.6	8.4	9.9	13.9	18.6	21.7	21.7	19.6	26.8	26.9	27.9	27.5	22.8
41	PWU	0.4	0.9	1.4	1.8	6.2	7.0	8.3	9.0	12.7	14.3	15.1	17.9	40.5	41.9	46.1	46.7	32.4
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.1	0.2	0.6	0.7	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	3.2	9.3	15.3	18.2	18.5	8.9	10.3	4.3	18.8	17.7	17.3	17.8	14.6
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	0.8	1.5	2.4	3.2	17.0	24.9	33.9	41.8	50.6	45.2	47.1	41.9	86.1	86.5	91.3	92.1	69.8
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	0.0	0.0	0.0	0.0	0.8	0.8	0.7	0.8	0.9	1.3	1.5	1.5	1.4	1.3	1.2	1.1	1.1
47	Non-Executive Management	0.1	0.2	0.2	0.4	8.6	6.6	8.8	12.0	14.3	21.2	27.0	26.3	30.7	30.5	30.2	28.4	25.1
48	Management Subtotal	0.1	0.2	0.2	0.4	9.3	7.4	9.5	12.8	15.2	22.5	28.5	27.8	32.2	31.8	31.4	29.5	26.2
49	Society	1.4	2.0	2.5	3.7	25.6	25.4	29.6	48.0	48.9	73.0	97.6	97.2	133.4	133.9	138.8	135.5	118.5
50	PWU	0.9	1.3	1.7	2.3	11.7	10.7	12.1	16.8	16.1	22.8	30.3	45.4	89.1	96.7	104.8	100.8	71.7
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.1	0.2	0.3	0.1	0.1	0.1	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	1.8	3.0	4.3	4.9	5.3	2.8	2.6	1.6	4.3	5.3	4.9	4.3	3.4
53	Unallocated[3]	0.2	0.2	0.3	0.5	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	2.6	3.8	4.8	6.8	53.6	46.7	55.8	82.9	85.9	121.0	159.2	172.3	259.0	267.8	280.0	270.1	219.8
55	Current Benefits (Statutory)	0.5	0.7	1.0	1.3	10.9	9.7	11.9	15.9	21.9	25.6	32.4	33.6	50.0	52.1	53.9	51.8	41.9
56	Current Benefits (Non-Statutory)	0.4	0.6	0.7	1.0	7.3	4.6	5.4	8.2	13.2	15.7	20.9	21.5	32.4	33.4	35.0	33.8	27.6
57	Pension & OPEB (Current Service)[1]	1.7	2.5	3.0	4.6	35.4	32.4	38.5	58.8	50.7	79.7	105.9	117.2	176.6	182.2	191.0	184.5	150.2
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	0.0	0.0	0.0	0.0	3.0	2.7	2.2	2.3	3.5	4.5	5.4	5.3	4.9	4.5	4.1	3.8	3.8
59	Non-Executive Management	0.3	0.6	0.8	1.3	28.6	24.5	31.3	37.9	54.7	74.8	95.2	92.1	105.9	105.4	104.3	97.9	86.0
60	Management Subtotal	0.3	0.6	0.8	1.3	31.6	27.2	33.6	40.2	58.1	79.3	100.6	97.4	110.8	109.9	108.4	101.7	89.7
61	Society	5.1	7.3	9.3	13.7	97.8	108.8	121.0	165.2	201.9	275.9	361.1	359.1	475.8	475.8	491.7	479.9	417.4
62	PWU	3.4	5.1	7.2	9.5	46.2	56.1	62.4	66.0	80.1	101.9	129.2	185.3	357.4	386.4	418.5	405.0	290.5
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.6	2.1	3.5	5.1	5.8	2.2	4.6	5.7	1.2	1.3	1.3	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	30.8	59.3	74.9	91.8	90.0	63.4	58.2	35.8	94.7	116.7	108.2	93.4	74.1
65	Unallocated[3]	2.0	2.8	4.0	4.9	34.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	10.8	15.9	21.3	29.4	241.6	253.6	295.4	368.2	435.9	522.7	653.7	683.3	1,039.8	1,090.0	1,128.1	1,080.0	871.8

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Regulated - PROVISION (Nuclear Facilities only)

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

Line No.	Regulated Facilities	Regulated Facilities (Nuclear)												
		2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	OPG Regulated - Direct													
1	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
2	Non-Executive Management	37.6	41.9	42.8	50.0	56.5	58.6	66.2	60.5	60.0	59.5	50.0	52.1	51.6
3	Management Subtotal	39.8	43.2	44.9	52.0	58.5	60.1	68.2	62.5	62.0	61.5	52.0	54.1	53.6
4	Society	141.3	153.9	161.9	186.9	221.1	258.7	303.7	287.6	259.6	245.2	207.4	209.4	211.6
5	PWU	185.6	198.2	202.3	210.2	306.9	575.0	605.5	486.8	434.5	419.5	368.5	369.5	369.5
6	Term/ETE/PECO Temporary	7.8	16.1	20.2	33.0	31.1	21.0	9.0	2.3	0.0	0.0	0.0	0.0	0.0
7	EPSCA	2.9	4.4	4.1	4.0	10.2	45.6	3.3	2.3	2.3	2.2	2.0	2.0	2.0
8	Subtotal	377.3	416.0	433.4	486.1	627.8	960.5	989.7	841.5	758.4	728.4	629.9	635.0	636.7
	OPG Regulated - Allocated													
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
11	Management Subtotal	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
12	Society	3.8	5.2	8.4	8.5	12.8	25.5	29.7	26.1	26.4	26.6	21.8	21.9	22.1
13	PWU	10.1	8.1	6.3	5.5	13.0	21.1	28.6	26.1	25.0	23.7	21.7	22.7	22.7
14	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Subtotal	15.7	16.1	18.1	17.8	31.9	54.9	66.5	60.1	59.1	57.5	50.1	51.2	51.4
	OPG Regulated Facilities													
17	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
18	Non-Executive Management	38.8	43.5	46.2	53.8	60.7	65.7	74.4	68.5	67.7	66.7	56.6	58.7	58.2
19	Management Subtotal	41.0	44.9	48.2	55.8	62.7	67.2	76.4	70.5	69.7	68.7	58.6	60.7	60.2
20	Society	145.0	159.1	170.3	195.4	233.9	284.2	333.4	313.7	286.0	271.8	229.2	231.4	233.7
21	PWU	195.7	206.3	208.6	215.7	320.0	596.2	634.1	512.8	459.5	443.2	390.2	392.2	392.2
22	Term/ETE/PECO Temporary	8.3	17.2	20.2	33.0	32.1	21.9	9.0	2.3	0.0	0.0	0.0	0.0	0.0
23	EPSCA	2.9	4.4	4.1	4.0	11.0	46.0	3.3	2.3	2.3	2.2	2.0	2.0	2.0
24	Total	392.9	432.1	451.5	503.9	659.7	1,015.4	1,056.2	901.6	817.5	785.9	680.0	686.2	688.1
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.3	0.4	0.5	0.4	0.5	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5
26	Non-Executive Management	5.9	6.8	7.7	8.1	9.8	10.8	12.3	11.5	11.7	11.8	10.6	11.2	11.4
27	Management Subtotal	6.2	7.2	8.2	8.6	10.3	11.1	12.8	11.9	12.1	12.3	11.1	11.7	11.9
28	Society	18.4	21.4	23.6	28.2	34.7	44.9	51.2	49.1	46.4	46.0	41.6	42.7	44.7
29	PWU[2]	21.4	23.1	24.3	26.4	43.3	79.5	84.8	69.0	63.5	63.2	58.1	59.3	61.4
30	Term[1]/ETE/PECO Temporary	0.9	2.0	2.3	4.3	4.6	2.8	1.0	0.2	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	0.4	0.7	1.0	0.7	2.1	8.1	0.5	0.4	0.4	0.4	0.4	0.4	0.4
32	Unallocated[3]	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	49.3	54.2	59.4	68.1	95.0	146.5	150.2	130.7	122.4	121.9	111.1	114.0	118.4
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.2	0.1	0.0
39	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	1.8	1.9	2.0	2.3	3.9	4.7	0.6	0.7	0.6	0.6	0.7	0.7	0.7
41	PWU	3.4	3.9	4.9	5.0	7.7	11.6	4.8	4.8	4.8	5.0	5.1	5.3	5.4
42	Term/ETE/PECO Temporary	0.1	0.2	0.3	0.4	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.1	0.1	0.1	0.3	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	5.3	6.1	7.3	7.9	12.2	17.5	5.5	5.5	5.5	5.6	5.8	6.0	6.2
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
47	Non-Executive Management	2.7	2.9	3.2	3.9	3.5	4.2	4.8	4.7	4.8	4.9	4.4	4.6	4.7
48	Management Subtotal	2.8	3.0	3.4	4.1	3.7	4.3	4.9	4.9	5.0	5.1	4.6	4.8	4.9
49	Society	8.0	8.3	9.4	12.8	12.4	17.7	20.2	20.1	19.3	19.2	17.3	17.8	18.6
50	PWU	8.9	8.4	9.2	11.1	14.4	28.8	31.6	26.9	24.7	24.6	22.7	23.2	24.1
51	Term/ETE/PECO Temporary	0.1	0.1	0.1	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Unallocated[3]	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	20.4	19.9	22.1	28.4	31.0	51.4	56.9	51.8	49.0	48.8	44.7	45.8	47.6
55	Current Benefits (Statutory)	3.2	3.0	3.3	4.2	6.6	10.4	10.1	8.9	8.3	8.3	7.6	7.8	8.1
56	Current Benefits (Non-Statutory)	2.3	2.1	2.3	3.0	5.0	6.8	7.7	6.7	6.3	6.3	5.7	5.9	6.1
57	Pension & OPEB (Current Service)[1]	15.0	14.8	16.5	21.2	19.3	34.3	39.0	36.3	34.4	34.3	31.3	32.2	33.4
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	0.4	0.5	0.7	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7
59	Non-Executive Management	8.6	9.7	10.9	12.1	13.4	15.0	17.1	16.2	16.5	16.7	15.0	15.8	16.1
60	Management Subtotal	9.0	10.2	11.6	12.7	14.0	15.4	17.7	16.8	17.2	17.4	15.7	16.5	16.8
61	Society	28.2	31.5	35.0	43.4	51.0	67.3	72.1	70.0	66.4	65.9	59.5	61.1	64.1
62	PWU	33.7	35.4	38.3	42.5	65.5	119.9	121.2	100.7	93.1	92.8	86.1	88.0	91.0
63	Term/ETE/PECO Temporary	1.0	2.3	2.8	5.0	5.3	3.2	1.2	0.3	0.0	0.0	0.0	0.0	0.0
64	EPSCA	0.5	0.9	1.1	0.8	2.5	9.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4
65	Unallocated[3]	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	75.0	80.2	88.8	104.4	138.2	215.4	212.7	188.1	177.0	176.4	161.7	166.0	172.2

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Regulated - Total

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

Line No.	OPG Regulated Facilities	Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
		2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	5.9	6.7	6.3	6.1	40.4	34.0	36.4	38.2	45.5	46.9	50.3	48.4	43.7	42.5	41.0	39.7	43.4
2	Non-Executive Management	78.7	79.8	81.1	77.9	684.8	581.7	586.5	659.7	777.6	821.2	916.6	867.8	822.6	797.6	771.3	754.4	761.0
3	Management Subtotal	84.6	86.5	87.4	84.1	725.2	615.6	622.9	697.9	823.1	868.1	966.9	916.1	866.3	840.1	812.4	794.2	804.4
4	Society	265.7	282.4	320.8	324.5	2,611.8	2,510.5	2,396.8	2,593.2	2,902.5	3,048.3	3,593.4	3,483.2	3,284.0	3,175.8	3,101.0	3,073.1	3,042.2
5	PWU	665.1	639.0	670.4	664.6	4,126.3	3,969.5	3,543.3	3,588.9	3,933.5	4,190.7	4,512.8	4,574.8	4,656.4	4,717.0	4,759.6	4,681.2	4,659.4
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	598.9	794.9	928.0	988.6	657.5	276.0	240.2	215.2	7.0	7.0	7.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	234.3	355.7	401.3	434.7	427.2	378.0	321.2	194.9	396.9	515.0	450.4	365.1	281.9
8	Subtotal	1,015.4	1,008.0	1,078.6	1,073.1	8,296.5	8,246.3	7,892.4	8,303.3	8,743.8	8,761.2	9,634.4	9,384.2	9,210.6	9,254.8	9,130.3	8,913.6	8,787.9
	OPG Regulated - Allocated																	
9	Executive	6.3	4.8	3.6	3.3	27.1	25.3	26.8	28.4	27.4	29.5	30.4	33.5	31.3	31.2	31.1	30.6	28.7
10	Non-Executive Management	61.3	57.5	56.1	57.4	298.4	292.7	302.7	345.3	383.7	393.9	444.1	453.2	417.0	414.1	406.6	404.8	392.8
11	Management Subtotal	67.7	62.3	59.7	60.7	325.5	317.9	329.5	373.6	411.1	423.4	474.5	486.7	448.3	445.3	437.6	435.4	421.5
12	Society	74.0	69.7	77.2	81.5	448.4	443.6	479.3	635.8	726.6	752.0	851.0	837.0	838.9	828.2	808.4	804.6	789.3
13	PWU	37.3	38.8	39.4	34.1	452.6	421.5	473.7	515.1	514.5	475.0	528.1	503.4	539.3	534.2	531.9	528.8	537.1
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	60.6	78.5	80.3	64.6	61.6	43.8	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	42.1	44.4	30.9	31.6	30.8	29.9	37.0	37.0	37.0	37.0	37.0	37.0	38.3
16	Subtotal	179.0	170.8	176.2	176.3	1,329.3	1,305.8	1,393.8	1,620.8	1,744.7	1,724.0	1,929.6	1,897.3	1,863.5	1,844.6	1,814.9	1,805.8	1,786.2
	OPG Regulated Facilities																	
17	Executive	12.2	11.5	9.9	9.5	67.5	59.2	63.2	66.6	72.9	76.4	80.7	81.9	75.0	73.7	72.1	70.4	72.1
18	Non-Executive Management	140.0	137.3	137.2	135.3	983.2	874.3	889.2	1,005.0	1,161.3	1,215.1	1,360.7	1,320.9	1,239.6	1,211.7	1,177.9	1,159.3	1,153.8
19	Management Subtotal	152.2	148.8	147.1	144.8	1,050.7	933.6	952.4	1,071.5	1,234.2	1,291.5	1,441.4	1,402.8	1,314.6	1,285.4	1,250.0	1,229.6	1,225.9
20	Society	339.8	352.1	398.0	405.9	3,060.2	2,954.1	2,876.1	3,229.0	3,629.2	3,800.3	4,444.5	4,320.2	4,122.9	4,003.9	3,909.4	3,877.7	3,831.5
21	PWU	702.3	677.8	709.8	698.7	4,578.9	4,391.0	4,017.1	4,104.0	4,448.0	4,665.7	5,040.8	5,078.2	5,195.6	5,251.2	5,291.5	5,210.1	5,196.6
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	659.5	873.4	1,008.4	1,053.2	719.1	319.8	279.2	248.5	7.0	7.0	7.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	276.4	400.0	432.2	466.3	458.0	407.9	358.2	231.8	433.9	551.9	487.4	402.0	320.2
24	Total	1,194.4	1,178.8	1,254.9	1,249.4	9,625.8	9,552.1	9,286.2	9,924.0	10,488.5	10,485.2	11,564.0	11,281.5	11,074.0	11,099.4	10,945.2	10,719.4	10,574.2
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	3.0	3.2	2.8	2.5	17.6	15.9	16.4	16.1	19.0	21.3	20.5	21.4	20.0	20.0	20.1	19.9	20.8
26	Non-Executive Management	18.7	18.5	19.1	19.5	141.9	126.8	138.3	153.4	181.5	202.9	220.7	223.0	218.9	220.1	222.2	223.7	228.6
27	Management Subtotal	21.7	21.7	21.9	22.0	159.6	142.6	154.7	169.5	200.5	224.3	241.3	244.4	238.9	240.0	242.3	243.5	249.4
28	Society	41.0	43.6	48.6	50.8	399.4	416.2	396.2	485.2	549.4	592.7	688.6	684.9	686.8	689.0	704.9	720.3	739.3
29	PWU[2]	75.8	72.3	74.2	75.3	528.4	550.7	484.4	562.1	671.8	641.9	664.8	698.9	744.5	776.1	819.1	826.5	851.7
30	Term[1]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	70.7	98.7	120.0	139.2	93.6	41.9	32.2	30.0	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	41.1	64.8	70.0	80.9	84.0	75.7	58.5	39.1	79.8	102.1	94.8	80.1	65.5
32	Unallocated[3]	(3.3)	(2.3)	(8.0)	(6.6)	19.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	135.2	135.3	136.7	141.5	1,219.1	1,273.0	1,225.2	1,436.9	1,599.3	1,576.4	1,685.5	1,697.2	1,751.3	1,808.5	1,862.4	1,870.5	1,905.9
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.8	1.0	1.1	1.0	7.9	6.8	7.0	9.1	7.7	9.8	8.8	8.5	8.9	9.6	9.9	9.9	10.4
35	Non-Executive Management	2.3	3.1	2.9	2.8	23.0	23.2	20.9	32.0	32.9	40.7	36.1	33.3	34.8	37.4	38.9	39.6	40.6
36	Management Subtotal	3.1	4.1	4.0	3.8	30.9	30.0	27.9	41.1	40.6	50.4	44.9	41.9	43.7	47.0	48.8	49.6	51.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.4	0.8	1.8	0.9	5.5	5.8	5.6	5.7	6.3	6.7	3.3	3.0	3.0	2.9	2.4	2.3	2.2
38	PWU	0.0	1.2	2.4	1.9	12.4	14.2	14.5	14.9	15.0	18.4	8.5	8.0	7.9	7.6	7.0	6.7	1.6
39	Total	0.4	2.0	4.3	2.8	17.9	20.0	20.1	20.7	21.3	25.1	11.8	11.1	10.8	10.5	9.4	9.0	3.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	2.3	3.0	3.4	4.2	43.6	48.7	52.2	56.5	62.6	55.3	50.1	46.5	51.5	48.7	53.3	51.8	51.0
41	PWU	5.9	8.5	9.1	10.1	84.9	94.6	85.8	97.0	112.6	94.0	91.5	89.6	119.1	111.8	128.2	122.5	121.4
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	8.8	11.7	16.4	21.0	12.3	4.4	3.2	2.5	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	4.7	12.2	19.2	22.0	23.8	11.8	11.2	5.0	19.8	18.5	18.3	18.6	15.3
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	8.2	11.5	12.5	14.4	142.1	167.2	173.7	196.5	211.3	165.4	156.0	143.6	190.4	179.0	199.7	193.0	187.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	1.2	1.3	1.1	1.0	7.7	8.7	8.8	5.9	7.1	7.9	7.5	8.5	7.8	7.7	7.8	7.7	8.1
47	Non-Executive Management	8.2	8.0	9.7	9.2	70.2	70.1	72.1	48.5	71.5	78.1	80.0	86.3	84.5	84.4	85.8	85.7	87.8
48	Management Subtotal	9.4	9.3	10.8	10.3	77.9	78.8	80.8	54.4	78.6	85.9	87.5	94.7	92.2	92.1	93.6	93.4	95.9
49	Society	18.0	18.7	24.1	23.9	192.5	211.6	207.7	149.7	216.8	221.8	251.9	266.7	268.7	270.6	280.0	284.9	293.1
50	PWU	31.9	30.9	35.9	34.4	235.8	254.0	228.2	155.5	232.0	241.1	229.3	254.7	274.6	285.2	302.0	305.9	316.4
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	5.1	6.0	8.4	9.4	7.8	3.0	2.0	1.8	0.1	0.1	0.1	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	2.8	3.3	4.7	4.7	5.1	4.5	3.3	2.0	4.8	5.7	5.4	4.7	3.8
53	Unallocated[3]	(0.8)	(1.1)	(2.6)	(1.3)	9.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	58.5	57.8	68.1	67.2	523.1	553.8	529.7	373.7	540.2	556.4	574.0	620.0	640.3	653.7	681.1	688.9	709.3
55	Current Benefits (Statutory)	8.7	9.0	9.1	9.2	77.6	73.8	80.1	89.3	105.3	106.6	120.0	119.5	124.3	127.2	133.1	132.1	134.3
56	Current Benefits (Non-Statutory)	6.1	7.1	6.6	6.8	47.7	55.6	54.5	59.5	64.7	78.6	82.0	81.6	85.4	87.7	91.4	92.0	94.6
57	Pension & OPEB (Current Service)[1]	43.7	41.7	52.4	51.2	397.7	424.4	395.2	224.9	370.3	371.1	371.9	418.9	430.6	438.8	456.6	464.9	480.3
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	5.0	5.5	5.0	4.5	33.2	31.3	32.1	31.1	33.8	38.9	36.8	38.4	36.6	37.3	37.9	37.5	39.2
59	Non-Executive Management	29.2	29.7	31.7	31.5	235.2	220.1	231.3	234.0	285.9	321.7	336.8	342.6	338.2	341.8	346.9	349.0	357.0
60	Management Subtotal	34.1	35.2	36.7	36.0	268.3	251.4	263.4	265.0	319.7	360.6	373.6	381.0	374.8	379.1	384.8	386.5	396.3
61	Society	61.7	66.1	77.9	79.8	640.9	682.4	661.7	697.2	835.1	876.5	993.9	1,001.1	1,010.0	1,011.3	1,040.6	1,059.4	1,085.6
62	PWU	113.6	112.8	121.6	121.8	861.6	913.5	812.9	829.5	1,031.4	995.4	994.1	1,051.2	1,146.1	1,180.8	1,256.3	1,261.7	1,291.1
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	84.6	116.5	144.8	169.6	113.7	49.2	37.4	34.4	1.2	1.3	1.3	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	48.7	80.3	93.9	107.6	112.9	92.0	73.0	46.1	104.4	126.4	118.4	103.4	84.7
65	Unallocated[3]	(4.1)	(3.4)	(10.6)	(8.0)	29.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	205.4	210.7	225.6	229.6	1,933.1	2,044.0	1,976.7	2,069.0	2,412.8	2,373.7	2,472.1	2,513.8	2,636.5	2,698.8	2,801.4	2,811.0	2,857.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

CCC Interrogatory #090

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 2
Exhibit F4, Tab 3, Schedule 1, Attachment 3

Question(s):

Please explain the linkage between the Compensation Philosophy & Peer Groups study (Attachment 2) and the Total Compensation Benchmarking study (Attachment 3). As part of the response, please advise whether the peer group recommendations from Attachment 2 are applied in Attachment 3. In the situation that there are differences between the peer group recommendations, please explain the reason for those differences.

Response

This response was prepared by WTW:

A company's compensation philosophy identifies the talent market and comparator group for assessing the competitiveness of its compensation. As discussed in Ex. L-F4-CCMBC-008, OPG adopted the compensation philosophy recommendations and resulting peer group criteria set out in Ex. L-F4-3-1, Attachment 2, with the exception of the recommendation to eliminate the forced 50:50 weighting between the public sector and private sector to Executive level roles. As detailed in Ex. L-F4-SUP-020, these criteria (Ex. L-F4-3-1, Attachment 2, p.17) were considered by WTW and applied to WTW's survey participants to determine the organizations to include in the Total Excluding Nuclear Authorized comparator group, other than for Executive level roles where a 50% public sector and 50% private sector weighting was applied. In addition, given the nature of pension fund organizations, WTW applied assets under management criteria as a substitute for the revenue criteria ($70 to $250 billion for executive roles and greater than $25 billion for non-executives). This substituted criterion was applied because revenue is not correlated with size and complexity in the pension fund industry.

Refer to L-F4-CCMBC-009 regarding the Nuclear Authorized peer group.

CCC Interrogatory #092

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 3, pp. 6-7, 20, 35

Question(s):

a) Please further explain the 7.5% adjustment for non-authorized nuclear operations roles at select career levels. As part of the response, please provide the number of OPG incumbents (and the percentage of incumbents relative to total) that are applied this adjustment.

b) WTW notes that "[o]ther one-time lump-sum awards (whether in cash or shares) are not captured in WTW's compensation surveys which could potentially understate the market results." Please explain what is included in the long-term incentives (as set out in the market definition data at p. 7 of the report) and how it differs from the Hydro One share grants that are provided to some of OPG's employees.

e) Please provide the percentage of the total peers in the benchmarking study that apply a 1.5x overtime rate.

Response

This response was prepared by WTW:

a) To understand if a pay premium existed for non-authorized roles in nuclear organizations versus the broader utility sector, pay levels for nuclear plan operations roles were compared between US utility and nuclear organizations. It was found that for select non-authorized nuclear operations roles (e.g., technician, supervisory), nuclear organizations provided, on average, a premium of 7.5% relative to the non-nuclear organizations.

   As there are insufficient data (only one directly comparable nuclear operator in Canada participated in WTW's survey), to report for non-authorized roles in nuclear facilities in Canada, the 7.5% premium was applied to the market data from the Canadian Total Sample (excluding Nuclear Authorized), for these select positions. The adjustment was applied to 2,376 OPG incumbents (22% of total OPG employees).

b) Long-term incentives included in the survey include grants of stock options, full-value shares (restricted or performance vesting) and long-term cash plans. Programs similar to OPG's Hydro One share grant are relatively uncommon in the market and distinguishable from typical long-term incentive programs based on program eligibility. The Hydro One share grant program is provided only to those incumbents that were employees at the time the program was implemented. It is not available to new employees, even if the new employee is doing the same or similar work. Long-term incentive plans in the market are provided to eligible employees in each year that they are granted and form part of the compensation and benefits package offered to new employees. As further detailed in Ex. F4-3-1, pp. 41-42, lump-sum awards for the comparators are not captured in WTW's surveys, which makes a direct comparison difficult given the unique nature of OPG's Hydro One share grant program.

c) The overtime analysis is based on the 2024 General Industry Compensation Policies and Practices Survey. Of the energy industry participants in this survey, 50% provide 2x the base rate and 30% provide 1.5x the base rate and 20% provide between 1x and 1.5x the base rate.

CCC Interrogatory #094

Interrogatory

Reference:
Exhibit F4, Tab 4, Schedule 1, p. 6

Preamble:

Second, with the last unit returning from refurbishment in 2026, OPG plans to purchase nuclear BI insurance for Darlington beginning in 2027 in order to mitigate the potential loss of earnings in the event of physical damage to the station from a nuclear peril. Standard BI policies exclude nuclear risks, making specialized coverage necessary for any such protection. While it has not historically procured this coverage, OPG considers this to be an appropriate time to add this product as part of its risk management practices in view of the company's evolving financial profile. OPG is facing increased funding needs to meet the forecast capital expenditures, and uninterrupted revenues from electricity generation at Darlington will be a critical source of such cashflow. Should an insurable BI event occur, having the appropriate insurance coverage will be important to mitigating the impact to OPG's funding profile and therefore credit ratings.

Question(s):

Please explain how BI insurance will operate in the event of an insurable event. For example, how would the insurance operate in the event that OPG lost production at a DRP unit in 2029 as a result of an insurable event? What counts as an insurable event?

Response

In the event of an insurable event, defined as a forced outage at a nuclear generating station that results from 1) any property at the facility damaged due to a nuclear event including unintended radioactive contamination, or 2) damage to property within the Nuclear Island (as defined below) caused by any non-nuclear insured peril (including but not limited to fire, explosion, machinery breakdown, and the like), nuclear business interruption coverage would respond to cover a loss of earnings, subject to policy terms and conditions, including the applicable limits. This coverage would not respond to a loss of earnings due to an outage not caused by physical damage, or for issues of "wear and tear" such as equipment condition degradation.

Like all business interruption insurance, the nuclear business interruption coverage is subject to a waiting period. A waiting period is the minimum amount of time, after an insured event, that must pass before coverage incepts. Similar to a deductible, where any losses below the deductible are not covered, in the case of a nuclear business interruption loss, any loss of earnings below the waiting period is not recoverable. The loss of earnings for the number of days above the waiting period is recoverable, subject to a maximum period (referred to as the indemnity period). The expected waiting period for this coverage is 120 days, which means that the forced outage would need to be at least approximately four months in order to trigger this coverage.

An example of how this coverage could be triggered in 2029 at Darlington is if the station were to experience a forced outage because of a fire that resulted in physical damage to the steam generator. In this scenario, OPG would experience a prolonged outage to repair the damage and return the unit to operation. As the steam generators are included in the definition of Nuclear Island, the nuclear property policy would respond to provide coverage for the direct physical damage to the property. Under the nuclear business interruption coverage, the resulting loss of earnings, because of the forced outage, would be covered by the nuclear business interruption coverage, subject to the limits, including the waiting period and the indemnity period.

Nuclear Island for the purpose of the coverage is defined as the areas of each unit comprising the nuclear reactor containment buildings and its contents; the vacuum building and its contents; that portion of the pressure relief duct work applicable to each unit including equipment therein; the spent fuel storage and its contents; that portion of the fuel handling tunnel and for the unit and any contents thereof; the service auxiliary bays including but not limited to change rooms, health physics department facilities, low activity disposal facilities and the laboratory but not including the control rooms; and any other property that is involved in the process, storage, transportation or handling of nuclear fuel or any radioactive material or heavy water.

CCMBC Interrogatory #004

Interrogatory

Reference:
F4-3-1, Page 48, Figure 13 – Comparison of OPG and Bruce PWU and Society Base Salary

Question(s):

a) Please confirm that Figure 13 does not include pensions and benefits.

b) Please file a figure similar to Figure 13 that compares total compensation including salary, overtime, pensions, and benefits including OPEBs.

Response

This response was prepared by Willis Towers Watson ("WTW"):

a) Confirmed.

b) WTW cannot assess a total compensation comparison between OPG and Bruce Power, as information on the value of Bruce Power's pensions and benefits is not publicly available.

CCMBC Interrogatory #005

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 1, FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for Nuclear Regulated Facilities.

Response

Refer to Attachment 1.

FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Nuclear Facilities (excluding DNNP LP)	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct												
1	Management	642.7	545.9	549.8	623.0	737.4	873.3	751.5	694.7	685.2	671.9	665.0	682.0
2	Society (Regular)	2,015.4	1,923.1	1,829.0	2,070.4	2,375.4	2,954.7	2,550.7	2,492.7	2,461.8	2,429.9	2,413.4	2,395.9
3	Society (Temporary)	255.3	240.6	203.3	152.2	103.6	130.8	232.9	76.5	53.1	46.8	43.8	40.9
4	PWU (Regular)	2,797.4	2,575.6	2,373.7	2,346.1	2,647.7	3,387.9	3,287.6	3,450.2	3,459.1	3,454.3	3,456.6	3,437.5
5	PWU (Temporary)	661.1	717.5	499.4	540.9	558.5	298.1	352.6	201.2	187.3	224.6	183.8	185.6
6	Term	584.2	723.7	830.8	928.1	624.2	240.2	214.2	6.0	6.0	6.0		
7	ETE/PECO Temp	14.7	71.2	97.3	60.5	33.3		1.0	1.0	1.0	1.0		
8	EPSCA	234.3	355.7	401.3	434.7	427.2	321.2	194.9	396.9	515.0	450.4	365.1	281.9
9	Subtotal	7,205.1	7,153.3	6,784.4	7,155.9	7,507.3	8,206.1	7,585.4	7,319.2	7,368.4	7,284.9	7,127.7	7,023.8
	Nuclear - Allocated												
10	Management	268.9	267.4	273.5	314.9	341.3	403.6	387.1	347.4	343.7	344.3	342.4	336.7
11	Society (Regular)	355.7	355.3	390.4	529.3	602.6	727.2	680.8	675.1	665.8	663.0	660.9	648.8
12	Society (Temporary)	30.0	30.0	26.7	35.2	41.1	27.1	9.2	6.5	3.4	2.0	2.0	2.0
13	PWU (Regular)	334.7	295.2	321.3	339.1	372.4	427.3	398.9	440.0	433.6	434.2	437.6	438.9
14	PWU (Temporary)	99.5	109.8	127.6	150.9	116.0	70.9	57.4	49.9	51.7	50.8	51.7	54.9
15	Term	59.6	72.8	74.6	63.2	61.6	39.0	33.3					
16	ETE/PECO Temp	1.0	5.7	5.7	1.4								
17	EPSCA	42.1	44.4	30.9	31.6	30.8	37.0	37.0	37.0	37.0	37.0	36.9	38.2
18	Subtotal	1,191.3	1,180.5	1,250.8	1,465.6	1,565.7	1,732.2	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4
	Nuclear Facilities												
19	Management (Regular)	911.5	813.3	823.3	937.9	1078.6	1276.9	1138.6	1042.2	1028.9	1016.2	1007.4	1018.7
20	Society (Regular)	2,371.0	2,278.4	2,219.4	2,599.8	2,977.9	3,681.9	3,231.5	3,167.9	3,127.6	3,092.9	3,074.3	3,044.7
21	Society (Temporary)	285.3	270.6	230.0	187.3	144.8	157.9	242.1	83.1	56.5	48.8	45.8	42.8
22	PWU (Regular)	3,132.1	2,870.8	2,695.0	2,685.2	3,020.1	3,815.3	3,686.5	3,890.1	3,892.7	3,888.5	3,894.2	3,876.4
23	PWU (Temporary)	760.7	827.3	626.9	691.8	674.4	369.0	410.0	251.1	239.1	275.5	235.5	240.5
24	Term	643.7	796.5	905.4	991.3	685.8	279.2	247.5	6.0	6.0	6.0		
25	ETE/PECO Temp	15.7	76.9	103.0	61.9	33.3		1.0	1.0	1.0	1.0		
26	EPSCA	276.4	400.0	432.2	466.3	458.0	358.2	231.8	433.9	551.9	487.3	402.0	320.0
27	Total	8,396.4	8,333.8	8,035.2	8,621.5	9,073.0	9,938.3	9,189.0	8,875.1	8,903.6	8,816.2	8,659.2	8,543.2
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
28	Management	165.2	151.6	159.1	183.1	209.3	251.9	229.6	220.8	225.0	231.5	234.1	243.5
29	Society (Regular)	318.2	333.5	315.4	408.0	463.3	580.5	525.1	536.8	545.7	564.6	577.8	593.6
30	Society (Temporary)	34.3	33.0	27.2	22.4	19.3	19.7	29.9	10.8	7.6	6.8	6.3	6.1
31	PWU (Regular)[2]	385.1	391.4	357.9	413.0	503.7	523.5	525.8	574.9	592.7	620.4	636.7	648.6
32	PWU (Temporary)[2]	77.4	88.4	59.9	73.0	76.1	36.8	45.5	24.7	23.6	30.0	24.5	25.4
33	Term[2]	68.0	90.9	105.4	131.5	88.0	32.2	29.8	1.0	1.0	1.0		
34	ETE/PECO Temp	2.7	7.8	14.5	7.8	5.5		0.2	0.2	0.2	0.2		
35	EPSCA[2]	41.1	64.8	70.0	80.9	84.0	58.5	39.1	79.8	102.1	94.8	80.1	65.5
36	Unallocated[3]	19.5											
37	Total	1,111.6	1,161.3	1,109.6	1,319.6	1,449.2	1,503.3	1,425.0	1,448.9	1,498.0	1,549.3	1,559.5	1,582.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
38	Society (Regular)	36.8	39.9	43.6	47.9	54.8	42.6	37.4	42.2	39.3	43.5	41.8	40.5
39	Society (Temporary)	2.6	4.3	2.5	1.5	1.3	0.4	0.3	0.0				
40	PWU (Regular)	63.7	64.9	62.1	70.1	83.8	68.8	65.8	96.1	87.3	101.5	95.9	91.4
41	PWU (Temporary)	11.8	16.1	9.2	9.2	10.1	3.0	2.6	0.1	0.1	0.1	0.1	0.1
42	Term	8.6	11.2	15.1	19.8	11.4	3.2	2.5					
43	ETE/PECO Temp	0.2	0.4	1.4	1.2	0.9	0.0						
44	EPSCA	4.7	12.2	19.2	22.0	23.8	11.2	5.0	19.8	18.5	18.3	18.6	15.3
45	Unallocated[3]												
46	Total	128.4	149.1	153.0	171.8	186.0	129.3	113.6	158.2	145.2	163.4	156.5	147.3
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
47	Management	67.5	68.7	69.3	48.1	68.4	77.3	76.1	72.3	72.9	75.6	76.0	79.3
48	Society (Regular)	162.4	179.7	174.3	129.0	186.6	216.3	211.0	211.5	215.2	225.1	229.3	236.5
49	Society (Temporary)	3.6	2.4	1.9	1.8	1.7	1.6	2.4	0.9	0.6	0.5	0.5	0.5
50	PWU (Regular)	191.9	203.6	183.0	119.0	186.3	187.2	203.1	218.8	224.8	237.8	243.4	251.7
51	PWU (Temporary)	7.0	6.7	5.1	5.9	6.6	2.8	3.3	1.8	1.7	2.1	1.8	1.9
52	Term	5.1	5.6	7.6	8.9	7.4	2.0	1.8	0.1	0.1	0.1		
53	ETE/PECO Temp	0.0	0.4	0.8	0.5	0.4	0.0	0.0	0.0	0.0	0.0		
54	EPSCA	2.8	3.3	4.7	4.7	5.1	3.3	2.0	4.8	5.7	5.4	4.7	3.8
55	Unallocated[3]	7.4											
56	Total	447.7	470.5	446.7	318.0	462.4	490.5	499.703	510.1	521.1	546.5	555.7	573.7
57	Current Benefits (Statutory)	68.4	65.8	69.0	77.3	91.3	102.8	96.8	99.6	101.7	107.1	106.6	108.3
58	Current Benefits (Non-Statutory)	40.8	46.3	45.6	50.1	54.8	70.1	65.7	68.0	69.9	73.3	74.2	76.6
59	Pension & OPEB (Current Service)[1]	338.5	358.3	332.0	190.6	316.3	317.7	337.2	342.6	349.5	366.2	375.0	388.8
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
60	Management	232.8	220.3	228.5	231.2	277.7	329.2	305.7	293.1	297.9	307.0	310.1	322.8
61	Society (Regular)	517.4	553.1	533.4	584.9	704.7	839.5	773.5	790.4	800.2	833.2	848.9	870.6
62	Society (Temporary)	40.5	39.8	31.6	25.7	22.2	21.8	32.6	11.7	8.2	7.4	6.8	6.6
63	PWU (Regular)	640.7	659.8	603.0	602.1	773.7	779.6	794.6	889.8	904.8	959.7	976.0	991.7
64	PWU (Temporary)	96.2	111.2	74.2	88.2	92.8	42.6	51.4	26.6	25.4	32.2	26.4	27.3
65	Term	81.7	107.8	128.0	160.1	106.9	37.4	34.2	1.0	1.0	1.1		
66	ETE/PECO Temp	2.9	8.7	16.7	9.5	6.8	0.0	0.2	0.2	0.2	0.2		
67	EPSCA	48.7	80.3	93.9	107.6	112.9	73.0	46.1	104.4	126.4	118.4	103.4	84.7
68	Unallocated[3]	26.9											
69	Total	1,687.7	1,780.9	1,709.3	1,809.4	2,097.7	2,123.1	2,038.3	2,117.2	2,164.3	2,259.2	2,271.7	2,303.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Line No.	Total Compensation $K/FTE Nuclear Facilities (excl DNNP)	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
70	Management	255.4	270.9	277.5	246.5	257.5	257.8	268.5	281.2	289.5	302.2	307.9	316.9
71	Society (Regular)	218.2	242.8	240.3	225.0	236.6	228.0	239.4	249.5	255.9	269.4	276.1	285.9
72	Society (Temporary)	141.9	147.1	137.3	137.4	153.3	138.1	134.7	140.6	145.8	150.9	149.1	153.4
73	PWU (Regular)	204.5	229.8	223.8	224.2	256.2	204.3	215.5	228.7	232.4	246.8	250.6	255.8
74	PWU (Temporary)	126.5	134.4	118.3	127.5	137.5	115.5	125.5	105.9	106.4	117.0	112.0	113.7
75	Term	127.0	135.3	141.4	161.5	155.9	134.0	138.1	169.6	174.1	182.3		
76	ETE/PECO Temp	185.0	112.5	162.5	153.7	205.1		207.9	213.1	218.9	229.2		
77	EPSCA	176.0	200.7	217.2	230.8	246.4	203.8	198.7	240.6	228.9	243.0	257.2	264.7

Line No.	Pension & Benefits as a % of Total Compensation^	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
78	Society & PWU (Regular)	31%	32%	31%	21%	25%	25%	26%	26%	26%	26%	26%	26%
79	Term/ETE/PECO Temp	6%	5%	6%	6%	7%	5%	5%	5%	5%	5%		

^ For Society and PWU regular staff calculated as Benefits (line 48 & 50) divided by Total Compensation (line 61 and 63). For Term/ETE/PECO Temp calculated as Benefits (line 52 & 53) divided by Total Compensation (line 65 & 66)

CCMBC Interrogatory #006

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 2, FTE, Compensation and Benefit Information for OPG's DNNP LP Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for DNNP LP Regulated Facilities.

Response

Refer to Attachment 1.

FTE, Compensation and Benefit Information for
OPG's DNNP LP Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	DNNP LP	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	DNNP LP - Direct						
1	Management	68.4	75.0	58.8	45.4	32.5	26.8
2	Society (Regular)	167.1	170.8	123.6	92.4	84.6	79.1
3	Society (Temporary)	10.1	7.6	6.1	3.7	0.2	(0.9)
4	PWU (Regular)	43.5	110.7	169.2	168.6	135.3	132.0
5	PWU (Temporary)	7.4	5.8	5.3	3.4	4.3	1.6
6	EPSCA						
7	Subtotal	296.4	369.9	363.1	313.6	256.8	238.5
	DNNP LP - Allocated						
8	Management	29.9	35.3	37.3	29.9	29.1	19.1
9	Society (Regular)	50.2	57.4	59.0	46.0	45.3	43.0
10	Society (Temporary)	0.3	0.9	1.3	1.1	1.1	1.1
11	PWU (Regular)	13.4	14.4	13.9	13.1	10.6	16.5
12	PWU (Temporary)	6.0	9.1	9.3	9.2	4.4	1.5
13	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
14	Subtotal	99.8	117.2	120.9	99.5	90.5	81.4
	DNNP LP Facilities						
15	Management	98.3	110.3	96.1	75.3	61.6	45.9
16	Society (Regular)	217.2	228.2	182.6	138.5	129.9	122.2
17	Society (Temporary)	10.4	8.5	7.4	4.9	1.3	0.2
18	PWU (Regular)	56.9	125.1	183.1	181.8	145.9	148.5
19	PWU (Temporary)	13.4	14.9	14.7	12.6	8.7	3.0
20	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
21	Total	396.2	487.1	484.0	413.1	347.3	319.9
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
22	Management	20.9	25.3	24.7	21.5	19.5	16.2
23	Society (Regular)	34.7	38.1	32.6	26.5	25.8	25.8
24	Society (Temporary)	1.5	1.3	1.1	0.8	0.2	0.0
25	PWU (Regular)[2]	9.0	21.8	31.4	32.5	26.7	29.5
26	PWU (Temporary)[2]	1.1	1.4	1.4	1.3	1.0	0.2
27	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
28	Total	67.3	87.8	91.2	82.6	73.2	71.7
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Society (Regular)	1.0	1.0	0.8	0.7	0.7	0.7
30	Society (Temporary)	0.0	0.0	0.0	0.0	0.0	
31	PWU (Regular)	0.2	0.5	0.8	0.8	0.6	3.0
32	PWU (Temporary)	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	1.2	1.6	1.7	1.5	1.3	3.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Management	7.1	8.3	7.4	6.0	4.9	3.7
35	Society (Regular)	13.9	15.0	12.4	9.9	9.3	8.8
36	Society (Temporary)	0.1	0.1	0.1	0.1	0.0	(0.0)
37	PWU (Regular)	3.0	7.5	10.7	11.3	8.8	8.8
38	PWU (Temporary)	0.1	0.1	0.1	0.1	0.1	0.0
39	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
40	Total	24.2	31.0	30.8	27.3	23.1	21.3
41	Current Benefits (Statutory)	4.2	5.5	5.4	4.8	4.0	3.8
42	Current Benefits (Non-Statutory)	3.3	4.2	4.2	3.8	3.2	2.9
43	Pension & OPEB (Current Service)[1]	16.7	21.3	21.1	18.7	15.9	14.5
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
44	Management (Regular)	28.0	33.5	32.1	27.5	24.4	19.8
45	Society (Regular)	49.6	54.1	45.9	37.0	35.7	35.3
46	Society (Temporary)	1.7	1.4	1.2	0.8	0.2	0.0
47	PWU (Regular)	12.2	29.9	42.9	44.7	36.1	41.2
48	PWU (Temporary)	1.2	1.5	1.5	1.4	1.0	0.3
49	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
50	Total	92.7	120.4	123.6	111.4	97.6	96.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

Line No.	Total Compensation $K/FTE DNNP LP	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
51	Management	284.5	303.8	333.7	364.5	395.8	431.7
52	Society (Regular)	228.4	237.0	251.2	267.2	274.9	288.9
53	Society (Temporary)	164.1	164.9	158.5	169.8	169.6	154.6
54	PWU (Regular)	213.8	238.6	234.5	245.7	247.8	277.7
55	PWU (Temporary)	90.8	101.6	104.9	114.6	119.4	85.7
56	EPSCA	148.8	176.1	171.1	178.0	187.0	191.3

CCMBC Interrogatory #007

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 3, FTE, Compensation and Benefit Information for OPG's Hydroelectric Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for Hydroelectric Regulated Facilities.

Response

Refer to Attachment 1.

FTE, Compensation and Benefit Information for OPG's Hydroelectric Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Hydroelectric Facilities	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Hydroelectric - Direct																
1	Management	84.6	86.5	87.4	84.1	82.5	69.8	73.1	74.9	85.7	93.6	96.2	96.6	96.1	95.0	96.7	95.7
2	Society (Regular)	262.1	276.1	309.3	313.6	333.4	334.6	352.6	359.4	417.6	496.0	516.0	528.5	525.0	524.9	527.8	525.0
3	Society (Temporary)	3.7	6.3	11.4	10.9	7.8	12.2	12.0	11.3	5.9	12.0	6.5	7.9	6.2	3.2	3.3	2.3
4	PWU (Regular)	634.0	602.8	630.4	627.7	627.3	622.1	601.4	608.9	650.8	755.8	778.4	778.9	779.2	781.6	783.6	785.3
5	PWU (Temporary)	31.1	36.3	40.0	36.9	40.4	54.4	68.9	93.0	76.5	71.0	105.3	109.7	116.9	127.1	117.6	117.4
6	Subtotal	1,015.4	1,008.0	1,078.6	1,073.1	1,091.4	1,093.0	1,108.0	1,147.4	1,236.6	1,428.3	1,502.4	1,521.5	1,523.4	1,531.8	1,529.0	1,525.6
	Hydroelectric - Allocated																
7	Management	67.7	62.3	59.7	60.7	56.6	50.6	56.0	58.8	69.9	70.9	69.7	65.5	64.3	63.4	64.0	65.7
8	Society (Regular)	71.2	67.4	73.8	78.5	59.5	54.7	58.0	66.4	78.1	91.9	95.1	98.1	98.0	95.9	95.0	94.1
9	Society (Temporary)	2.9	2.3	3.4	2.9	3.3	3.7	4.2	4.9	4.9	4.8	1.4	0.8	0.6	0.3	0.3	0.3
10	PWU (Regular)	33.3	34.6	35.9	29.6	15.9	13.0	18.8	18.5	20.5	24.5	23.0	21.4	21.1	20.2	20.3	21.0
11	PWU (Temporary)	4.0	4.2	3.5	4.5	2.5	3.5	6.1	6.5	5.6	5.3	4.7	4.5	4.4	4.3	4.3	4.4
12	Subtotal	179.0	170.8	176.2	176.3	137.9	125.4	143.0	155.1	179.0	197.5	193.9	190.3	188.5	184.2	183.9	185.4
	Hydroelectric Facilities																
13	Management	152.2	148.8	147.1	144.8	139.1	120.3	129.1	133.7	155.6	164.5	165.9	162.1	160.4	158.4	160.7	161.3
14	Society (Regular)	333.2	343.5	383.1	392.1	392.9	389.2	410.6	425.8	495.7	588.0	611.1	626.6	623.0	620.8	622.8	619.1
15	Society (Temporary)	6.5	8.6	14.8	13.8	11.1	15.9	16.1	16.1	10.8	16.8	7.9	8.7	6.8	3.5	3.6	2.6
16	PWU (Regular)	667.3	637.4	666.3	657.3	643.2	635.0	620.2	627.4	671.3	780.3	801.3	800.3	800.3	801.8	803.9	806.3
17	PWU (Temporary)	35.1	40.5	43.5	41.4	42.9	57.9	75.0	99.5	82.2	76.3	110.0	114.2	121.3	131.4	121.9	121.7
18	Total	1,194.4	1,178.8	1,254.9	1,249.4	1,229.3	1,218.4	1,251.0	1,302.6	1,415.6	1,625.8	1,696.3	1,711.9	1,711.9	1,716.0	1,712.9	1,711.1
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
19	Management	24.8	25.8	25.9	25.7	25.2	21.0	23.5	27.5	31.8	34.3	35.7	36.5	37.3	38.1	39.5	40.7
20	Society (Regular)	40.8	43.5	48.9	50.3	51.2	54.2	57.2	58.9	71.7	89.7	95.7	101.8	104.1	108.2	112.1	115.6
21	Society (Temporary)	0.6	0.9	1.5	1.5	1.2	1.4	2.0	1.7	1.4	1.9	0.9	1.1	0.9	0.5	0.5	0.4
22	PWU (Regular)[2]	72.6	69.3	72.6	73.2	73.7	79.4	72.8	80.3	95.4	102.6	109.6	112.9	116.3	120.9	125.1	129.8
23	PWU (Temporary)[2]	3.3	4.1	4.0	4.0	4.7	5.7	8.3	10.7	11.7	10.4	15.9	16.8	18.3	20.9	19.3	19.8
24	Unallocated[3]	(3.3)	(2.3)	(8.0)	(6.6)	0.4											
25	Total	138.7	141.4	144.9	148.1	156.4	161.7	163.7	179.2	211.9	238.9	257.8	269.0	276.9	288.7	296.4	306.2
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
26	Society (Regular)	2.2	3.0	3.4	4.1	4.2	4.5	6.0	7.0	6.6	7.1	7.8	8.3	8.5	9.0	9.3	9.8
27	Society (Temporary)	0.0	0.0	0.1	0.1	0.1	(0.1)	0.1	0.1	0.0	0.0	0.0					
28	PWU (Regular)	5.7	8.1	8.7	9.8	8.9	12.8	13.5	16.2	17.1	18.5	18.9	20.2	21.3	22.9	23.2	24.1
29	PWU (Temporary)	0.2	0.4	0.4	0.4	0.5	0.8	1.0	1.5	1.6	1.2	2.0	2.2	2.4	2.9	2.7	2.7
30	Unallocated[3]																
31	Total	8.2	11.5	12.5	14.4	13.7	18.0	20.6	24.8	25.3	26.8	28.8	30.7	32.2	34.8	35.2	36.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
32	Management	9.4	9.3	10.8	10.3	10.3	10.1	11.5	6.3	10.3	10.2	11.6	11.6	11.7	12.1	12.5	12.9
33	Society (Regular)	18.0	18.6	24.0	23.7	26.4	29.3	31.4	18.6	28.4	33.8	39.2	41.2	42.2	44.5	45.8	47.3
34	Society (Temporary)	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0
35	PWU (Regular)	31.6	30.6	35.5	34.1	36.5	43.2	39.4	29.6	38.1	38.6	44.2	45.1	46.5	49.2	50.5	52.6
36	PWU (Temporary)	0.3	0.4	0.4	0.3	0.4	0.6	0.7	1.0	0.9	0.7	1.1	1.2	1.3	1.5	1.4	1.4
37	Unallocated[3]	(0.8)	(1.1)	(2.6)	(1.3)	1.7											
38	Total	58.5	57.8	68.1	67.2	75.4	83.3	83.0	55.7	77.8	83.4	96.2	99.2	101.8	107.3	110.2	114.3
39	Current Benefits (Statutory)	8.7	9.0	9.1	9.2	9.2	8.0	11.0	11.9	13.9	17.2	18.5	19.3	20.0	21.2	21.5	22.2
40	Current Benefits (Non-Statutory)	6.1	7.1	6.6	6.8	7.0	9.2	8.9	9.4	9.8	12.0	12.7	13.2	13.6	14.4	14.6	15.2
41	Pension & OPEB (Current Service)[1]	43.7	41.7	52.4	51.2	59.2	66.1	63.1	34.3	54.1	54.2	65.0	66.7	68.2	71.8	74.0	77.0
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
42	Management	34.1	35.2	36.7	36.0	35.5	31.1	34.9	33.8	42.0	44.4	47.2	48.1	49.1	50.2	51.9	53.6
43	Society (Regular)	61.0	65.1	76.2	78.1	81.7	88.0	94.5	84.5	106.7	130.5	142.7	151.3	154.8	161.8	167.2	172.7
44	Society (Temporary)	0.7	1.0	1.7	1.7	1.4	1.4	2.3	2.0	1.5	2.1	1.0	1.2	0.9	0.5	0.5	0.4
45	PWU (Regular)	109.9	108.0	116.9	117.1	119.1	135.4	125.7	126.1	150.7	159.6	172.8	178.2	184.0	193.0	198.8	206.6
46	PWU (Temporary)	3.8	4.9	4.7	4.7	5.6	7.1	10.0	13.1	14.2	12.4	19.1	20.2	22.0	25.3	23.3	23.9
47	Unallocated[3]	(4.1)	(3.4)	(10.6)	(8.0)	2.1											
48	Total	205.4	210.7	225.6	229.7	245.5	263.0	267.4	259.6	315.1	349.0	382.7	399.0	410.9	430.8	441.8	457.2

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Line No.	Total Compensation $K/FTE Hydroelectric Facilities	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
49	Management	224.3	236.2	249.3	248.5	255.4	258.3	270.6	253.1	270.0	270.2	284.5	297.0	305.9	316.9	323.2	332.2
50	Society (Regular)	183.2	189.7	199.0	199.2	208.0	226.1	230.2	198.6	215.3	222.0	233.5	241.4	248.5	260.6	268.4	279.0
51	Society (Temporary)	104.6	112.8	115.4	123.4	122.3	90.6	139.5	123.1	138.6	126.2	129.7	133.6	138.6	142.2	143.1	144.4
52	PWU (Regular)	164.7	169.4	175.4	178.1	185.2	213.3	202.6	201.0	224.5	204.5	215.6	222.6	230.0	240.7	247.3	256.2
53	PWU (Temporary)	107.0	120.2	108.6	114.6	129.6	122.7	133.6	132.0	172.4	162.1	173.2	176.7	181.2	192.5	191.3	196.6

CCMBC Interrogatory #008

Interrogatory

Reference:
F4-3-1, Attachment 2, Southlea Report, Page 18, Recommendations

Question(s):

Did OPG accept and implement all of Southlea's recommendations. If the answer is no, please list recommendations that OPG rejected and / or did not implement?

Response

No, OPG did not fully implement all of Southlea's recommendations. Specifically, Southlea's recommended peer group ownership structure would have entirely eliminated the forced 50:50 weighting between the public sector and private sector comparators. The recommended approach is intended to enable more robust data and more accurately reflect the market in which OPG competes for talent (Ex. F4-3-1, Attachment 2, p.17). While OPG carefully considered this recommendation and recognizes it would better reflect the competitive talent market, as noted at Ex. F4-3-1, p. 43, lines 22-24, OPG decided to continue to apply the 50:50 public sector/private sector forced weighting for Executives, as a measure of ongoing restraint, notwithstanding that this group continues to benchmark well below the target market range.[1]

[1] Target market range is defined by WTW as +/- 10% of the peer group median or "P50".

CCMBC Interrogatory #009

Interrogatory

Reference:
F4-3-1, Attachment 3, Page 5, Comparator Groups, and page 33 Nuclear Authorized – Executives and Non-Executives and page 34 Pension & Benefits Analysis

Question(s):

a) Why were different comparator organizations selected for Nuclear Authorized – Executives and Non-Executives and Pension & Benefits Analysis?

b) For example, why was Tennessee Valley Authority (TVA) selected as a comparator organization for the Nuclear Authorized – Executives and Non-Executives but not for the Non-Executives and Pension & Benefits Analysis?

c) Is WTW aware that Concentric did not include TVA in its proxy group of utilities (C1-1-1, Attachment 1, Page 14 and Pages 103-109, Concentric Report)?

Response

This response was prepared by WTW:

a) and b)

Different comparator organizations were selected for the Nuclear Authorized comparator group and the Total Excluding Nuclear Authorized comparator group based on the talent market with the nuclear professional body of knowledge required for the Nuclear authorized roles. The Nuclear Authorized comparator group includes Canadian and U.S.-based organizations, including Tennessee Valley Authority (TVA).

A single comparator group of Canadian organizations for pension and benefits market data has been used for all roles, including those roles matched to the Total Excluding Nuclear Authorized sample and the Nuclear Authorized sample because organizations typically offer common pension and benefit plans across all roles and skill sets, and pension and benefits plans vary substantially by country given the differences in regulatory environments. As such, TVA, for example, was excluded from the pension and benefits comparator group

c) No.

CCMBC Interrogatory #010

Interrogatory

Reference:
F4-3-1, Attachment 4, Page 3, 2024 Base Salary Comparison | Society of United Professionals

Question(s):

a) Considering that the base salary for Control Room Shift Supervisor, Training Supervisor is 20% lower at OPG than at Bruce Power, are employees in that category leaving OPG to work for Bruce Power?

b) What is the difference in pension and benefits between OPG and Bruce Power for employees in that category?

c) Are there any differences in job descriptions between OPG and Bruce Power for employees in that category?

Response

a) Refer to Ex. L-F4-CCMBC-003, part (a).

b) Refer to Ex. L-F4-CCMBC-004, part (b).

c) Bruce Power LP's job descriptions are not available to OPG or WTW; therefore, neither OPG nor WTW can comment on any differences between the job descriptions.

CCMBC Interrogatory #011

Interrogatory

Reference:
F4-3-2, Page 1, Pension and Other Post-Employment Benefit Costs

Question(s):

a) Does OPG agree that the vast majority of ratepayers, and in particular younger ratepayers, will never receive pensions and other benefits (if they receive pensions and other benefits at all) anywhere approaching the value of the pensions and other benefits described in this section that are allocated for OPG employees? If OPG does not agree with that statement, please provide evidence to support why OPG believes young ratepayers could expect to receive similar pensions and benefits to OPG employees.

b) How would OPG convince young ratepayers just starting out in their careers that they should accept paying higher rates so that OPG employees can receive lucrative pensions and benefits that these ratepayers are unlikely to receive in their lifetimes?

Response

a) and b)

OPG declines to provide the requested response on the basis of speculation and relevance. With the assumptions and characterizations underlying parts a) and b) of this interrogatory, as well as the broad and general nature of the question, OPG is unable to comment and provide a meaningful or responsive answer that would be relevant. The question seeks information and comment regarding the future personal pension and benefits of ratepayers, particularly younger ratepayers. OPG does not have access to such information, and any such answer would be speculative as it would be entirely dependent on assumptions that have no basis in fact. Furthermore, OPG notes that matters relating to the individual pension and benefit arrangements of ratepayers are outside the scope of and irrelevant to this proceeding.

PWU Interrogatory #010

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 48 of 50

Preamble:

The reference states:

Bruce Power remains OPG's closest competitor for attracting and retaining talent. Both Bruce Power and OPG generate electricity in the same energy market, operate similar nuclear technology, have a workforce comprised of similar roles, and have employees represented by the same unions.

WTW undertook a comparison of OPG's wages to those provided by Bruce Power. The results of this comparison are captured in Attachment 4, and a summary is provided below in Figure 13. The analysis shows that Bruce Power's unionized wages are 24% higher for PWU represented positions and 9% higher for Society-represented positions. For licensed nuclear roles, such as the Control Room Shift Supervisor (Society), Bruce Power's unionized wages are up to 20% higher.

Question(s):

a) Please quantify the impact on the test period revenue requirement had OPG wages been equivalent to Bruce Power wages.

b) Please quantify the impact on the test period revenue requirement had OPG's total compensation been equivalent to that of Bruce Power.

Response

a) On average, Bruce Power LP's wage rates are 24% higher than OPG for PWU-represented employees and 9% higher for Society-represented employees as of 2025. For the purposes of quantifying the revenue requirement as if OPG had such wages equivalent to Bruce Power LP's wages, all else equal, the resulting estimated revenue requirement impact of such hypothetical wages and the resulting impact on pension costs is shown in Chart 1 below.

   The pension cost impact represents the hypothetical change in the current service cost assuming the higher wages had been in effect historically. The wage impacts

are determined on the basis of compensation costs reflected in OM&A expenses. The revenue requirement impacts would result in an increase to the OPG and DNNP LP revenue requirements and are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1 -
Estimated Hypothetical Impact of Equivalent Bruce Power Wages on OPG and DNNP LP Revenue Requirements

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear	133	135	148	148	179
Regulated Hydroelectric	37				
DNNP Facilities	6	6	6	8	11

b) As noted in Ex. L-F4-CCMBC-004, OPG understands that WTW cannot assess a total compensation comparison between OPG and Bruce Power LP, as information on the value of Bruce Power LP's pensions and benefits is not publicly available.

PWU Interrogatory #012

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 35 of 50

Preamble:

Figure 9 – Employee Contributions and Employee/Employer Contribution Ratio

Figure 9 – Overview of Employee Contributions

Employee Pension Contributions [1]	above Earnings Limit)			Contribution Ratio (Employee/Employer)
	MG	PWU	Society	
2014	7 / 7	5 / 7	7	24% / 76%
2015	7 / 7	6 / 8	7	24% / 76%
2016	7.3 / 8.25 / 2	7 / 9	8	29% / 71%
2017	7.6 / 9.5 / 4.5	7.5 / 10	9	32% / 68%
2018	7.6 / 9.5 / 4.5	7.5 / 10	9	33% / 67%
2019	7.6 / 9.5 / 4.5	7.5 / 10	9	34% / 66%
2020	7.6 / 9.5 / 4.5	7.5 / 10	9	32% / 68%
2021	7.6 / 9.5 / 4.5	7.5 / 10	9	33% / 67%
2022	7.6 / 9.5 / 4.5	7.5 / 10	9	31% / 69%
2023	7.6 / 9.5 / 4.5	7.5 / 10	9	38% / 62%
2024	7.6 / 9.5 / 4.5	7.5 / 10	9	36% / 64%
2025 [2]	7.6 / 9.5 / 4.5	7.5 / 10	9	47% / 53%
2026 [3]	7.6 / 9.5 / 4.5	7.5 / 10	9	50% / 50%

Question(s):

a) Please quantify the impact on the 2027 revenue requirement specifically, as well as on the revenue requirement for the test period, had the contribution ratio remained at 36%/64% as in 2024 instead of the latest ratio of 50%/50%.

Response

a) If the contribution ratio remained unchanged at 36%/64% from 2026 onwards, the estimated impact on the revenue requirement for 2027 and the remaining IR term is provided in Chart 1 below. These impacts are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1 -
Estimated Hypothetical Impact of 36%/64% Pension Contribution Ratio on OPG and DNNP LP Revenue Requirements

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear	(11)	(16)	(22)	(29)	(36)
Regulated Hydroelectric	(3)				
DNNP Facilities	(1)	(1)	(1)	(1)	(1)

As noted in Ex. L-F4-SUP-027, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.

PWU Interrogatory #014

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 11 of 50

Preamble:

The reference states:

OPG has a mature and experienced workforce. By year-end 2025, approximately 11% of active regular employees (~1,065) will be eligible to retire with an undiscounted pension, with an additional 15% becoming eligible to retire between 2026-2031. Compared to EB-2020-0290, the lower number of employees eligible for fully undiscounted retirement in 2025 reflects changes in the retirement eligibility formula negotiated in 2015 that have now taken effect (see Section 7.0.2 below), and the shift in OPG's overall demographics.

Question(s):

a) Please provide the number of actual retirements from 2020 to 2025 and number of employees eligible to retire in each year from 2026 to 2031.

Response

a) Chart 1 shows the actual number of OPG retirements for the period 2020-2025.

Chart 1 – Total OPG Actual Retirements Per Year (2020-2025)

Total OPG Actual Retirements						
Year	2020	2021	2022	2023	2024	2025
	428	308	362	217	233	278

Chart 2 shows the number of OPG employees eligible to retire in each year 2026-2031 respectively.

Chart 2 – Total OPG Employees Eligible to Retire Per Year (2026-2031)

Total OPG Employees Eligible to Retire*						
Year	2026	2027	2028	2029	2030	2031
	80	245	241	294	302	345

*Numbers are not cumulative, and reflect pension rule changes (Ref. Ex. F4-3-1, p. 36, lines 12-19).

SEC Interrogatory #185

Interrogatory

Reference:
F4-1-1, p. 17

Question(s):

Please provide a table reconciling the increases in depreciation from 2021 to 2031 to "the impact of in-service additions across the fleet".

Response

The table below provides the depreciation and amortization associated with the regulated hydroelectric in-service additions in a given year, beginning with 2021, that accumulate to the change in depreciation and amortization expense from 2020 to 2031 in Ex. F4-1-1, Table 1 related to in-service additions across the fleet.

Year of In-Service	Depreciation and Amortization on In-Service Additions ($M)
2021	6.3
2022	11.2
2023	6.5
2024	10.6
2025	7.2
2026	9.1
2027	14.4
2028	18.9
2029	19.0
2030	16.1
2031	5.5
Total	**126.5**

SEC Interrogatory #186

Interrogatory

Reference:
F4-1-1, Attachment 2, p. 5

Question(s):

Please explain why the end-of-life ("EOL") dates for Bruce A and Bruce B in the table are not December 31, 2064, as described in the text.

Response

The average station EOL dates in the referenced table for the Bruce A and Bruce B nuclear generating stations are correct and remain as December 31, 2061 and December 31, 2052, respectively. These dates represent an average of individual generating unit EOL dates for the respective stations, which are in turn based on such estimated dates specified in the Amended and Restated Bruce Power Refurbishment Implementation Agreement ("ARBPRIA") between the Independent Electricity System Operator and Bruce Power made public in December 2015. Although the ARBPRIA ends on December 31, 2064, such dates specified therein are earlier than December 31, 2064, resulting in the above average station EOL dates. There have been no changes to these dates since they were implemented by OPG for depreciation and amortization purposes effective December 31, 2015.[1]

At Ex. F4-1-1, Attachment 2, p. 5, OPG's Depreciation Review Committee ("DRC") concluded that, notwithstanding the level of technical confidence in the post-refurbishment operation of Bruce Units 3-8 beyond the above noted dates: i) there was insufficient evidence to extend any of such dates beyond the end date of the ARBPRIA; and ii) that while a modest extension of the EOL dates for these units to match December 31, 2064 was possible, such a change was not recommended at that time due to a relatively small impact and as the dates would remain subject to further reassessment until Bruce Power's refurbishment of all six units is completed (and the actual post-refurbishment in-service dates are known).[2] These recommendations are reflected in OPG's financial statements prepared in accordance with US GAAP and the corresponding amounts of Bruce Lease net revenues presented in this Application.

[1] For example, see EB-2016-0152: Ex. F4-1-1, p. 5, lines 8-24 and Attachment 1, p. 4; EB-2020-0290, Ex. F4-1-1, p. 4, Chart 1.
[2] The refurbishment of Bruce Units 1 and 2 was previously completed in 2012 and as such they have a sooner EOL date assumption, resulting in an overall sooner average station EOL date for the Bruce A station.

SEC Interrogatory #188

Interrogatory

Reference:
F4-1-1, Attachment 12, p. 16-17

Question(s):

With respect to the Concentric, *Assessment of Regulated Hydroelectric Asset Depreciation Rates* (December 2019) Report, please restate Table 1 to include, for each of the four categories, the gross book value and accumulated depreciation each year.

Response

The referenced Table 1 is a listing of multiple asset classes for OPG's regulated hydroelectric facilities. OPG is unable to identify the "four categories" noted in the question and is therefore unable to provide any responsive information.

SEC Interrogatory #189

Interrogatory

Reference:
F4-3-1, p. 21, Figure 4a

Question(s):

Please explain why the percentage of nuclear allocation management – supervisors to total employees has increased as compared to 2020-2023.

Response

Refer to Chart 1 below where the average Management-Supervisory FTEs as a percentage of total regular and non-regular FTEs for the nuclear facilities (refer to Ex. F4-3-1, p.21, Figure 4a) is approximately 10% for the period 2024-2031.

As discussed at Ex. F4-3-1, p.13, lines 14-20, the previously implemented reduction in management positions discussed in EB-2020-0290 was maintained until 2023, at which point the planning efforts for the potential Pickering refurbishment, the progression of the DNNP and the ramping up of the hydroelectric work program necessitated the addition of management and other positions to enable the planning and readiness for execution of these major investments.

OPG continues to leverage the centralization of functions implemented in 2020, including Support Services, to more effectively scale project teams up (or down), using existing organizational structures.

Chart 1 – Nuclear including DNNP facilities FTEs 2020-2031

Figure 4a - Nuclear FTE	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Mgmt-Supervisory	732	665	668	760	890	1,055	1,030	969	945	917	902	902
Total FTE (Regular and Non Regular)	8,396	8,334	8,035	8,621	9,073	9,938	9,589	9,368	9,398	9,249	9,038	8,909
Mgmt-Supervisory % of Total FTE	8.7%	8.0%	8.3%	8.8%	9.8%	10.6%	10.7%	10.3%	10.1%	9.9%	10.0%	10.1%

*Refer to Ex. F4-3-1, Figure 4a

SEC Interrogatory #190

Interrogatory

Reference:
F4-3-1, p. 35

Question(s):

Does the contribution ratio set out in Figure 9 reflect the actual or forecast the overall OPG-wide contribution ratio, or does this reflect only a sub-set of employees (e.g. newer employees)?

Response

The pension contribution ratios in Ex. F4-3-1, Figure 9 reflect the actual and forecast overall OPG-wide contribution ratios.

SEC Interrogatory #191

Interrogatory

Reference:
F4-3-1

Question(s):

With respect to the Ontario Public Sector Salary Disclosure List:

a) For each of the most recent years available, what percentage of OPG's employees were on the Public Sector Disclosure list?

b. For most recent year available, please provide the total number of OPG employees whose salaries are at or above, a) $100,000, and b) $200,000.

Response

a) The percentage of total employees on OPG's payroll listed on the Public Sector Salary Disclosure ("PSSD") was approximately 82% in 2024 and 84% in 2025.

b) The PSSD published in 2026 listed 10,346 OPG employees earning $100,000 or more in 2025, including 1,964 OPG employees earning $200,000 or more.

SEC Interrogatory #193

Interrogatory

Reference:
F4-3-1, p. 5

Preamble:

The evidence states notes that the current collective agreement with the PWU expires on March 31, 2027, and the Society collective agreement has expired.

Question(s):

a) For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the Society's collective agreement?

b) Please quantify the impact, if any, between the response to part (a) and what was decided by way of the Arbitration Decision, dated January 26, 2026. Please provide all calculations.

c) For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the next PWU collective agreement (beginning April 1, 2027)?

Response

a) Refer to Ex. L-F4-Staff-227.

b) The estimated revenue requirement impact of the differences in wage escalation in the Society Arbitration decision, dated January 26, 2026 relative to the assumptions in Ex. L-F4-Staff-227 for the years 2026-2028 is an increase of approximately $2M for OPG's nuclear facilities in 2027 and less than $1M annually for the remainder of the IR term and for each of the regulated hydroelectric facilities and the DNNP facilities.

c) Refer to Ex. L-F4-Staff-227.

SEC Interrogatory #195

Interrogatory

Reference:
F4-3-1, p. 30

Question(s):

With respect to the Stakeholder Return Program ("SRP"):

a) Please provide the percentage applied to forecast corporate earnings before tax ("EBT") for each year 2016 to 2031. Please note if the percentage is different for nuclear and hydroelectric.

b) Please explain how the percentages for 2026-2031 were determined.

Response

a) As noted in Ex. F4-3-1, p. 31, the Applicants adopted a financial results model starting in 2021 for deriving the SRP amounts based on a percentage applied to forecast EBT. A single forecast EBT and a single percentage is used across the corporation and therefore underpins the SRP costs attributed to each of OPG's nuclear facilities and regulated hydroelectric facilities. The percentages applied to forecast EBT for each year from 2021-2026 are shown in Chart 1 below. Refer to Ex. L-F4-AMPCO-123 for the 2027-2031 years.

Chart 1
Stakeholder Return Program - Percentage of Forecast EBT Applied

2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Plan
[redacted]					

b) As noted in Ex. F4-3-1, p. 31, and Ex. F4-4-1, pp. 7-8, the percentage of forecast EBT for a given year takes into consideration the business objectives for that year and the industry range of 2%-7% of EBT provided by Willis Towers Watson. On average, over both the 2021-2026 period and the 2027-2031 period, approximately 2% has been applied to forecast EBT, which is at the lowest end of the industry range. The percentage applied to the forecast EBT, the corporate balanced scorecard results, and total incentive amounts are subject to approval by OPG's

Board of Directors, with consideration for reasonableness and ensuring adequate funding to effectively drive performance.

SEC Interrogatory #197

Interrogatory

Reference:
F4-3-1, Attachment 3

Question(s):

With respect to the WTW, *Total Compensation Benchmarking Study*:

a) Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.

b) Please revise the results of the study so that they provide separate results for each of the general and energy industry.

Response

This response was prepared by WTW:

a) As discussed in Ex. L-F4-CCMBC-008, OPG adopted the compensation philosophy recommendations and resulting peer group criteria set out in Ex. L-F4-3-1, Attachment 2, with the exception of eliminating the forced 50:50 weighting between the public sector and private sector to Executive level roles. As detailed in Ex. L-F4-SUP-020 and Ex. L-F4-CCC-90, these criteria were considered by WTW and applied to WTW's survey participants to determine the organizations to include in the Total Excluding Nuclear Authorized comparator group. This was the only methodological change compared to the compensation study filed in EB-2020-0290.

b) An analysis providing separate results for the general industry and the energy industry cannot be completed in a timely manner, as it would take approximately four to six months and would require a change in the comparator group. We note that in the current comparator group, there are limited general industry organizations (10 to 14 depending on if referencing executive or non-executive Total Excluding Nuclear Authorized comparator group) and this would be insufficient to provide quartile statistics covering the same number of roles as covered in the current benchmarking study. Furthermore, this approach would be inconsistent with the methodology of the study, which applies OPG's compensation philosophy and definition of talent market to the peer comparator group.

This response was prepared by OPG:

OPG's position is that the approach postulated in part b) of the question would also be inconsistent with the EB-2020-0290 OEB-approved settlement proposal, which required OPG to complete its compensation benchmarking study on the current two-segment benchmarking approach only.

SEC Interrogatory #200

Interrogatory

Reference:
F4-2-1

Question(s):

Please provide an estimate of the weighted average capital cost allowance ("CCA") rate for each of, a) nuclear operations capital, b) support services capital, and c) regulated hydroelectric capital, each year between 2022 and 2031, excluding the impact of the AIIP.

Response

The chart below provides the estimated weighted average CCA rates for OPG's nuclear facilities and OPG's regulated hydroelectric facilities for each year between 2022 and 2031, inclusive of the associated Support Services capital expenditures, based on the information provided at Ex. F4-2-1, Tables 11-20 (regulated hydroelectric) and Ex. F4-2-1 Tables 23-32 (nuclear). The rates are calculated by dividing total CCA for the year by the average of undepreciated capital cost ("UCC") at the beginning of that year and the UCC at the end of that year. OPG does not track this information separately for Support Services. The weighted average CCA rates have been calculated with reference to actual information for the 2022-2024 period and forecast information for the 2025-2031 period based on the pre-filed evidence.

As the existing accelerated incentive investment property ("AIIP") program in effect since November 2018 is not elective and automatically applies when computing CCA under the Income Tax Act and Regulations (Canada), consistent with the Application, its impact is excluded from the calculation of the weighted average CCA rate after the scheduled phase-out at the end of 2027.

For clarity, this analysis does not include the effects of the reinstatement of the AIIP (referred to as RIIP) that was enacted, for qualifying property acquired on or after January 1, 2025, by the *Budget 2025 Implementation Act, No. 1* in March 2026. As discussed at Ex. F4-2-1, p. 8, lines 20-24, the Application does not reflect these provisions, which were proposed but not legislated at the time.

OPG Weighted Average Capital Cost Allowance Rates

	OPG Nuclear Facilities	Regulated Hydroelectric Facilities
2022	10.2%	7.9%
2023	10.3%	10.7%
2024	9.9%	6.9%
2025	9.7%	7.4%
2026	10.2%	9.9%
2027	11.2%	12.5%
2028	9.8%	9.1%
2029	9.5%	8.5%
2030	9.0%	7.9%
2031	8.9%	7.5%

Board Staff Interrogatory #192

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p. 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a
Ref 3: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

Reference 1 shows nuclear facilities, DNNP LP, and hydroelectric regulated facilities FTEs for 2020-2031, broken down according to direct vs allocated.

Question(s):

a) For each of nuclear facilities, DNNP LP, and hydroelectric regulated facilities, please show how many of the allocated FTEs are treated as capital vs. OM&A for 2026-2031.

Response

a) The forecast Allocated FTEs by Capital and OM&A for 2026-2031 for each of OPG's nuclear facilities, DNNP LP, and OPG's regulated hydroelectric facilities are shown in Charts 1-3 below, respectively.

Chart 1 – OPG Nuclear Facilities Allocated FTEs
OM&A vs Capital for 2026-2031

Nuclear Facilities (excluding DNNP LP)	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Nuclear - Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	1,254.6	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
Capital	288.9	420.2	406.1	408.9	399.3	327.8

Chart 2 – DNNP LP Allocated FTEs
OM&A vs Capital for 2026-2031

	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
DNNP LP Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	59.3	74.4	82.5	76.9	76.7	71.2
Capital	40.5	42.8	38.4	22.6	13.8	10.2

Chart 3 – OPG Regulated Hydroelectric Facilities Allocated FTEs
OM&A vs Capital for 2026-2031

	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Hydroelectric Facilities Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	164.0	153.6	150.8	146.1	146.6	151.5
Capital	29.9	36.8	37.6	38.1	37.3	33.9

Board Staff Interrogatory #219

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 2 / Schedule 1 / p. 5

Preamble:

OPG states that for 2020-2026, regulatory income taxes for the prescribed facilities are presented on a combined nuclear and hydroelectric basis, with total taxes before scientific research and experimental development (SR&ED) investment technology credits (ITCs) allocated based on each business' regulatory taxable income, while 2027-2031 are presented on a standalone basis, i.e. hydroelectric and nuclear are separate.

Question(s):

a) Please provide a bridge from the 2026 combined prescribed-facilities tax calculation to the separate 2027 standalone hydroelectric and nuclear tax calculations, showing separately:
   i. Changes arising from the move away from the combined calculation
   ii. Changes in tax loss utilization
   iii. Changes in SR&ED ITC attribution
   iv. Any changes in reference amounts used for tax-related deferral and variance accounts.

Response

a) i. and ii.

Attachment 1 provides a breakout of the forecast standalone regulatory taxable income for the year 2026 presented at Ex. F4-2-1, Table 3, col. (g) between OPG's prescribed nuclear and regulated hydroelectric facilities in a manner comparable to the respective standalone regulatory taxable income calculations for years 2027-2031 presented at Ex. F4-2-1, Tables 3b and 3d.

In addition, Chart 1 below shows a breakdown of the forecast regulatory income taxes for the two regulated businesses for the year 2026, comprised of regulatory income taxes before SR&ED ITCs and the SR&ED ITCs. In determining regulatory income taxes before SR&ED ITCs for each of the businesses in the historical and bridge periods, such regulatory income taxes for the prescribed facilities as a whole

(for 2026, at Ex. F4-2-1, Table 3, line 28 plus line 29) are allocated to each of the two business proportionately to their regulatory income before taxes, unless there is a negative regulatory taxable income for one of the businesses, in which case the negative regulatory taxable income of the applicable business reduces or eliminates the regulatory income tax expense of the other business.

iii. There are no differences in SR&ED ITC attribution as between the combined and stand-alone regulatory income tax calculations referenced. SR&ED ITCs are predominantly directly attributed to each business based on the underlying expenditures giving rise to the ITCs.

iv. The appliable reference amounts for all of OPG's deferral and variance accounts in effect during 2026 are determined in accordance with the EB-2020-0290 Payment Amounts Order and are not subject to change.

Chart 1 – Breakdown of OPG's 2026 Forecast Regulatory Income Taxes ($M)

	2026		
	Regulated		
	Nuclear	Hydroelectric	Total
Income Taxes Before SR&ED ITC	(20.3)	0.0	(20.3)
SR&ED ITC	(16.6)	(3.3)	(19.9)
Total Regulatory Income Taxes	(36.9)	(3.3)	(40.2)

Board Staff Interrogatory #220

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 2 / Schedule 1 / p. 1
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / p. 15
Ref 3: Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

OPG states that hydroelectric income taxes are embedded in the hydroelectric capital-related revenue requirement and C-factor because those taxes are predominantly (although not entirely) capital-related.

In Reference 2, OPG states that as of the effective date of the payment amounts order, the Income and Other Taxes Variance Account (OPG) reference amounts for hydro will be the corresponding 2027-2031 annual income tax provisions in Exhibit F4-02-01 Table 3b of the evidence. The Income and Other Taxes Variance Account shows that for hydroelectric, the account has a 2024 balance of ($17.3 million), with ($9.2 million) already approved for 2025-2026 amortization, and ($8.1 million) proposed for disposition in this application over 36 months.

Question(s):

a) Please provide, for each year of 2027-2031:
   i. The hydroelectric income tax amount embedded in the capital-related revenue requirement/C- factor
   ii. The portion OPG considers capital-related versus non-capital-related
   iii. An explanation of how OPG avoids duplication between recovery through the C-factor and additions to the Income and Other Taxes Variance Account (OPG) and any related hydro capital variance accounts.

b) For the Income and Other Taxes Variance Account – Hydroelectric,
   i. Please provide a reconciliation from the 2024 audited balance of ($17.3 million) to the ($8.1 million) proposed for disposition in this application, identifying each component by vintage, driver and amount.
   ii. Reconcile which amounts were previously approved for amortization in EB-2023-0336 and explain the derivation of the ($9.2 million) shown in Reference 2.
   iii. Reconcile the annual ($2.7 million) amortization amounts in 2027-2029 to the tax model line “Regulatory Liability Amortization – Income and Other Taxes Variance Account” in Reference 3.

iv. Confirm whether the account balance already includes the associated income tax impacts, i.e. gross-up, for each component.

Response

a)

i. The hydroelectric income tax amounts embedded in the forecast capital-related revenue requirement ("CRRR") underpinning the C-factor calculation are found at Ex. I1-2-1, Table 2, line 4 and Ex. F4-2-1, Table 3b, line 23.

ii. For purposes of determining the forecast CRRR underpinning the C-factor, as referred to at Ex. A1-3-2, p. 18, Note *, OPG has reflected the full amount of forecast regulatory income tax expense for the regulated hydroelectric facilities, calculated at Ex. F4-2-1, Table 3b, line 23, as capital related. This simplified approach recognizes that the large majority of such regulatory income tax expense is capital related, including in relation to regulatory earnings before tax that are tied to the return on equity amounts and most of the adjustments to regulatory earnings before tax. For example, between the addition for depreciation and amortization expense at Ex. F4-2-1, Table 3b, line 2 and the deduction for capital cost allowance at such line 10, these adjustments comprise over 90% of the net additions/deductions across such lines 9 and 16. For purposes of calculating the actual CRRR to determine entries into the Global Hydroelectric Capital Variance Account ("GHCVA"), OPG will only capture income tax impacts that are specific to capital related items.

iii. The interaction between the GHCVA, the Capacity Refurbishment Variance Account and various income tax-related accounts is discussed at Ex. A1-3-2, pp. 23-26. The process described in that evidence would ensure no duplication of recovery across these accounts. There would be no duplication possible between the forecast CRRR underpinning the C-factor and the income-tax related accounts because such accounts would only record differences relative to the forecasts underpinning the payment amounts, not the forecasts themselves.

b)

i. The requested continuity can be found at Ex. H1-2-1, Table 1, line 5, cols. (a) to (d).

ii. The ($9.2M) is the sum of, and is therefore fully addressed, by the OEB-approved amortization for 2025 of ($4.6M) and for 2026 of ($4.6M) from EB-2023-0336 Decision and Order, Appendix A, Table 1, line 5, cols. (h) and (i), respectively.

iii. Refer to Ex. F4-2-1, Table 3b, line 5, cols. (a) to (c), where the annual amounts for 2027 to 2029 are equal to the corresponding annual amortization amounts of ($2.7M) found at Ex. H1-2-1, Table 1, line 5.

iv. The underlying balance of the Income and Other Taxes Variance Account (OPG), and therefore the associated annual amortization amounts at Ex. F4-2-1, Table 3b, line 5, do contain certain income tax impacts, namely as part of Entry (i) into the account as shown at Ex. H1-1-1, Table 6. Specifically, these impacts stem from lines 3 and 4 of that table by virtue of the "gross-up" calculation contained in such line 5. These impacts total approximately ($1.5M), translating into ($0.5M) per year as part of the proposed ($2.7M) annual amortization amount for the 2027-2029 period.[1] OPG does not propose to adjust the approvals sought in the Application on account of the resulting duplication of ($0.5M) per year to the benefit of ratepayers, having acknowledged such potential outcome at Ex. F4-2-1, p. 15, footnote 12. At that reference, the Application explains that, given the modest balances sought for disposition in respect of the account, a simplified approach was taken to base the associated adjustment to regulatory earnings before tax on the full account balance, rather than isolating the portion that was not already "grossed-up". As that evidence also notes, going forward, OPG will ensure that all components of the account consistently reflect the income tax impacts, eliminating the need for this adjustment to earnings before tax altogether. The Applicants intend to apply this approach to entries into the Income and Other Taxes Variance Account (OPG) and the proposed Income and Other Taxes Variance Account (DNNP), effective January 1, 2027.

[1] The ($1.5M) amount is calculated as (Ex. H1-1-1, Table 6: line 3, col. (c) plus line 4, col. (f)) multiplied by (1 / (1-25%) minus 1).

Board Staff Interrogatory #222

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 5-6
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, the Applicants state that OPG also succeeded in maintaining the ability to use the Power Workers' Union (PWU)-represented term-based employees (Term Employees) and the Society of United Professionals (the Society)-represented extended temporary employees (ETEs). The Applicants state that this was a critical strategy in mitigating the impacts of a Pickering shutdown.

Reference 2 provides FTE, Compensation and Benefit information for OPG nuclear, OPG hydroelectric, DNNP LP. The Applicants' workforce classifications include Management, Society, PWU, Term/ETE/PECO Temporary, and Electrical Power Systems Construction Association (EPSCA).

Question(s):

a) Please show the number of Society ETE and PWU Term employees within each of the workforce classifications at Reference 2.

b) If Society ETE and PWU Term employees do not account for all employees in the Term/ETE/PECO Temporary classification, please explain.

c) Please explain how EPSCA employees' compensation is determined, given that those employees do not belong to the unions or management.

Response

a) Refer to Ex. L-F4-CCMBC-005, Attachment 1 for breakdown of PWU Term and Society ETE/PECO Temporary employees at Reference 2.

b) Society ETE and PWU Term employees account for all employees within the Term/ETE/PECO Temporary classification.

For clarity, the terms “ETE” and “ETE/PECO” are used interchangeably in OPG’s pre-filed evidence to refer to Society-represented classifications of employees that could be hired to avoid adding regular staff in circumstances where additional regular employees were likely to be laid off as a result of the planned shutdown of Pickering.

c) Electrical Power Systems Construction Association ("EPSCA") category of employees are unionized. The EPSCA is the employer association which negotiates and administers collective agreements directly with Building Trades Unions ("BTU") on behalf of employers in the electrical construction sector (including OPG). The BTU have exclusive labour jurisdiction to represented individuals in the province’s skilled trades labour workforce. When these employees are directly hired by OPG, they continue to be represented by the BTU and are compensated in accordance with the collective agreement(s) negotiated between the EPSCA and the BTU.

Board Staff Interrogatory #224

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 8
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, OPG states that at the end of 2024, it employed 10,332 Regular, Term and Extended Temporary Employees.

Reference 2 provides FTE totals by business. The 2024 value is 9,073 (p. 1 line 18) for OPG's nuclear business and 1,415.6 (p. 3 line 12) for OPG's hydroelectric business. The sum of these values is 10,488.6.

Question(s):

a) Please reconcile the difference between the value at Reference 1 and the sum using Reference 2 calculated by OEB staff in the preamble.

Response

a) The two References are not equivalent and cannot be reconciled.

Reference 1 includes total OPG headcount for Regular, Term and Extended Temporary Employees for both regulated and non-regulated businesses and represents the number of employees planned. It does not include other temporary resources such as EPSCA resources.

Reference 2 refers to Full Time Equivalent ("FTE") for Nuclear and regulated Hydroelectric businesses, including all temporary resources. Refer to Ex. L-F4-AMPCO-127 for a detailed definition of FTE.

Board Staff Interrogatory #225

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 11
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / pp. 15-17

Preamble:

At Reference 1, OPG states that by year-end 2025, approximately 11% of active regular employees (~1,065) will be eligible to retire with an undiscounted pension, with an additional 15% becoming eligible to retire between 2026-2031.

Reference 2 describes OPG's redeployment strategy. The strategy begins with redeploying 1,300 employees from the Pickering station to other areas of OPG Nuclear.

Question(s):

a) Please describe and explain how OPG Nuclear's redeployment strategy will affect the FTE counts of departments within Pickering Refurbishment, the Darlington generating station, and the DNNP. Please include an explanation of FTE trends in each of the described departments in the 2027-2031 period.

b) Does OPG allow for a period of overlap for the purpose of knowledge transfer between retiring employees and their replacements? How are overlaps of this kind reflected in the 2026-2031 compensation costs and FTE counts?

Response

a) Nuclear redeployments – for example a change in an employee's job, location, or reporting organization – are being grouped and timed in such a way as to ensure that as certain work programs cease at Pickering and the station moves into the Pickering Refurbishment Program ("PRP") and as the Darlington Refurbishment Program ("DRP") reaches completion, employees are redeployed according to business need. It is expected that approximately 1,500 employees will be redeployed, including approximately 1,300 employees from Pickering Operations and approximately 200 employees from the DRP. Of these, about 1,200 employees are planned to move to the PRP, approximately 150 to Darlington Operations, approximately 30 to the DNNP, and the remainder to other parts of the organization. In addition to redeployments, approximately 200 employees previously supporting the DRP are expected to be reassigned to different project work.

Exhibit F2-1-1, Table 2a, line 6 (as corrected in Ex. L-F2-Staff-199) shows Nuclear Facilities OM&A FTEs (i.e., Pickering and Darlington) decline by 1,163 FTEs between 2026 and 2027 as the employees are redeployed per above, followed by a generally stable trend between 2027 and 2030 and then increasing by 615 in 2031 with the expected Pickering Unit 5 return to service and the redeployment of employees back to Pickering.

Exhibit F2-1-1, Table 2a, line 24 shows an increase of 1,209 PRP FTEs between 2026 and 2027, as the employees are redeployed per above, followed by a generally stable trend between 2027 and 2030, before declining by 724 in 2031 as Pickering Unit 5 returns to service and the majority of the employees are redeployed back to operate Pickering.

Exhibit F2-1-1, Table 2b, line 6 and line 1 show DNNP Facilities FTEs increasing for OM&A and declining for Capital over the 2027-2031 period, as the DNNP Unit 1 approaches and reaches completion in 2030.

Exhibit F2-1-1, Table 2a, line 18 shows a decline of approximately 620 FTEs for the DRP between 2025 and 2026 and then a further decline to none over the 2027-2031 period, due to the completion of the DRP.

Note that although the two are directionally aligned, the redeployment values in the first part of this response represent the number of Regular employees, whereas the FTE values in the second part of this response represent charged labour hours divided by scheduled hours, including Non-Regular FTEs.

b) OPG does not prohibit overlaps between a retiring employee and their replacement for purposes of knowledge transfer, where it is necessary. These instances are managed operationally. Overlaps between retiring employees and their replacements are not reflected in the 2026-2031 forecast compensation costs and FTE counts.

Board Staff Interrogatory #226

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 14

Preamble:

At Reference 1, the Applicants state that since 2023, OPG has hired approximately 500 project managers and engineers and expects to continue hiring to ensure the appropriate resourcing through the IR term.

Question(s):

a) Are project managers' compensation costs capitalized to projects, expensed to OM&A, or a mix of both? Please explain.

Response

a) The compensation costs of project managers assigned to capital projects are capitalized, as such amounts represent expenditures directly attributable to such projects. The compensation costs of project managers not assigned to capital or nuclear liability (i.e., nuclear provision) projects are expensed to OM&A costs.

Board Staff Interrogatory #227

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 18

Preamble:

At Reference 1, OPG states that the increases in compensation costs over time primarily reflect the higher collective agreement wage increases over the last several years as well as wage escalation assumptions over the IR term.

Question(s):

a) Please provide the annual wage escalation assumptions for 2025-2031 for the Power Workers' Union (PWU), the Society of United Professionals (the Society), and management.

Response

a) The annual wage escalation assumptions for 2025-2031 as reflected in OPG's 2025-2031 Business Plan and the Application are provided in Chart 1 below. The escalation is effective January 1 of a given year, unless otherwise noted.

Chart 1 – Annual Wage Escalation by Employee Group (2025-2031)

	2025	2026	2027	2028	2029	2030	2031
PWU (Effective April 1)	3.75%	2.50%					
Society	3.25%						
Management	3.82%						

Board Staff Interrogatory #229

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 21
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Figure 4b

Preamble:

At Reference 1, OPG states that the FTEs for the regulated hydroelectric facilities were largely stable over the 2020-2023 period, before increasing by 9% in 2024 and 15% in 2025, mainly to support major capital projects, including the turbine-generator refurbishment program.

Reference 2 shows that there are no Term employees or Extended Temporary Employees (ETE) in the regulated hydroelectric business.

Question(s):

a) Please confirm that none of the increase in regulated hydroelectric FTE count in 2024 and 2025 is due to the hiring of Term employees or ETEs. If not confirmed, please reconcile with Reference 2.

b) Did OPG consider using Term employees or ETEs to support its hydroelectric major capital projects? Please explain.

c) Does OPG expect its FTE complement to decline following the completion of its major capital projects? Please explain.

Response

a) Confirmed.

b) As described in Ex. F4-3-1, p. 17, lines 12-14, in accordance with collective agreement provisions, Term and ETE employees can only be hired instead of regular staff in the Nuclear business, in circumstances where employees are likely to be laid off as a result of the planned shutdown of Pickering. Instead, as described in Ex. F1-2-1, p. 4, lines 16-21, the hydroelectric regional operations groups make use of incremental short-term labour resources that are primarily temporary staff with a start and end date, where appropriate. These resources are deployed to

address peak workload demands, seasonal operational requirements, and to provide coverage for short-duration staff absences or vacancies.

c) The expected future size of OPG's regulated FTE complements at the completion of its major capital projects presented in this Application, which extend beyond the IR term, is not currently known and will depend on a range of factors including future business needs and project requirements.

Board Staff Interrogatory #231

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 30-31
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 3

Preamble:

At Reference 1, OPG states that the Stakeholder Return Program is a short-term (i.e., single year) pay for performance incentive plan for eligible management employees, intended to deliver a portion of total compensation on a pay for performance basis. Since 2021, OPG has used a financial results model for deriving the amounts based on a percentage applied to forecast corporate earnings before tax.

Reference 2 is a Total Compensation Benchmarking Study conducted by Willis Towers Watson.

Question(s):

a) Please describe any changes to the Stakeholder Performance Program since EB-2020-0290.

b) Please confirm that the Stakeholder Performance Program costs are equivalent to the “Target Incentive” included under Total Direct Compensation in Reference 2.

Response

a) There have been no changes to the Stakeholder Return Program (“SRP”) since EB-2020-0290.

b) In the Total Compensation Benchmarking Study conducted by Willis Towers Watson, the “Target Incentive” included under Total Direct Compensation in Reference 2 includes the SRP at target, and other incentive plans as applicable.

Board Staff Interrogatory #233

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1-2

Preamble:

OPG states that the forecast 2027-2031 pension and other post-employment benefit costs (OPEB) for OPG's regulated facilities and the Darlington New Nuclear Program (DNNP) facilities included in the proposed revenue requirement are determined in accordance with US Generally Accepted Accounting Principles (GAAP). As in prior applications, OPG's accrual costs for pension and OPEB include several components.

Question(s):

a) Please confirm whether the pension and OPEB amounts included in the 2027-2031 revenue requirement are based on total annual accrual costs determined under OPG's US GAAP accounting treatment.

b) Please provide a breakdown for each forecast year showing the components of annual pension and OPEB cost reflected in the forecast revenue requirement, by major plan.

c) Please identify any components of annual pension and OPEB cost determined for financial reporting purposes that are not included in the forecast revenue requirement and explain why they are excluded.

d) Please confirm if OPG's accrual costs for pension and OPEB includes a component related to the amortized actuarial gains or losses (which is allowed under US GAAP). If so, please provide the figures for historical periods and also 2027-2031 related to the amortized actuarial gains or losses.

Response

a) Confirmed.

b) Provided below is the breakdown for the components of the forecasted annual pension and OPEB accrual costs for years 2027-2031 as attributed to each of OPG's nuclear facilities, OPG's regulated hydroelectric facilities and the DNNP LP's facilities in the manner described in Ex. F4-3-2, Section 4.2. The current service cost components shown correspond to Ex. F4-3-2, Chart 12, Chart 13 and Chart 14, respectively.

Chart 1
Pension and OPEB Cost Components for 2027-2031 – OPG Nuclear

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
Pension					
Current Service Cost	250.6	255.3	267.3	272.7	282.1
Interest Cost	603.0	612.3	629.8	645.9	659.2
Expected Return on Assets	(831.0)	(853.8)	(886.0)	(911.5)	(932.7)
Amortization of Past Service Cost	0.0	0.0	0.1	0.7	0.7
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	22.6	13.8	11.2	7.8	9.3
OPEB					
Current Service Cost	92.0	94.2	98.9	102.3	106.7
Interest Cost	117.3	120.6	125.6	130.2	134.4
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	2.7	2.7	2.7	2.8	3.3
Amortization of Actuarial Losses (Gains)	(8.9)	(7.4)	(6.2)	(5.2)	(3.8)
Immediate Recognition of LTD Losses (Gains)	0.9	0.9	1.0	1.1	1.1
Total	204.0	211.0	222.0	231.2	241.7
Total					
Current Service Cost	342.6	349.5	366.2	375.0	388.8
Interest Cost	720.3	732.9	755.4	776.1	793.6
Expected Return on Assets	(831.0)	(853.8)	(886.0)	(911.5)	(932.7)
Amortization of Past Service Cost	2.7	2.7	2.8	3.5	4.0
Amortization of Actuarial Losses (Gains)	(8.9)	(7.4)	(6.2)	(5.2)	(3.8)
Immediate Recognition of LTD Losses (Gains)	0.9	0.9	1.0	1.1	1.1
Total	226.6	224.8	233.2	239.0	251.0

* Numbers may not add due to rounding.

Chart 2
Pension and OPEB Cost Components for 2027-2031 – Regulated Hydroelectric

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
Pension					
Current Service Cost	48.8	49.8	52.4	53.8	55.8
Interest Cost	116.9	119.4	123.4	127.8	131.2
Expected Return on Assets	(161.1)	(166.5)	(173.6)	(180.2)	(185.5)
Amortization of Past Service Cost	0.0	0.0	0.0	0.1	0.1
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	4.6	2.7	2.2	1.5	1.6
OPEB	OPEB				
Current Service Cost	17.9	18.4	19.4	20.2	21.2
Interest Cost	22.8	23.6	24.6	25.7	26.7
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	0.5	0.5	0.5	0.6	0.7
Amortization of Actuarial Losses (Gains)	(1.8)	(1.5)	(1.2)	(1.0)	(0.8)
Immediate Recognition of LTD Losses (Gains)	0.2	0.2	0.2	0.2	0.2
Total	39.6	41.2	43.5	45.7	48.0
Total	Total				
Current Service Cost	66.7	68.2	71.8	74.0	77.0
Interest Cost	139.7	143.0	148.0	153.5	157.9
Expected Return on Assets	(161.1)	(166.5)	(173.6)	(180.2)	(185.5)
Amortization of Past Service Cost	0.5	0.5	0.5	0.7	0.8
Amortization of Actuarial Losses (Gains)	(1.8)	(1.5)	(1.2)	(1.0)	(0.8)
Immediate Recognition of LTD Losses (Gains)	0.2	0.2	0.2	0.2	0.2
Total	44.2	43.9	45.7	47.2	49.6

* Numbers may not add due to rounding.

Chart 3
Pension and OPEB Cost Components for 2027-2031 – DNNP Facilities

(millions of dollars)	2027	2028	2029	2030	2031
Pension					
Current Service Cost	15.6	15.4	13.6	11.5	10.6
Interest Cost	37.4	38.3	32.7	27.9	25.5
Expected Return on Assets	(51.6)	(53.4)	(45.9)	(39.2)	(35.8)
Amortization of Past Service Cost	0.0	0.0	0.0	0.0	0.0
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	1.4	0.3	0.4	0.2	0.3
OPEB					
Current Service Cost	5.7	5.7	5.1	4.4	3.9
Interest Cost	7.2	7.4	6.5	5.7	5.3
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	0.2	0.2	0.1	0.1	0.1
Amortization of Actuarial Losses (Gains)	(0.5)	(0.4)	(0.3)	(0.2)	(0.1)
Immediate Recognition of LTD Losses (Gains)	0.1	0.1	0.1	0.0	0.0
Total	12.7	13.0	11.5	10.0	9.2
Total					
Current Service Cost	21.3	21.1	18.7	15.9	14.5
Interest Cost	44.6	45.7	39.2	33.6	30.8
Expected Return on Assets	(51.6)	(53.4)	(45.9)	(39.2)	(35.8)
Amortization of Past Service Cost	0.2	0.2	0.1	0.1	0.1
Amortization of Actuarial Losses (Gains)	(0.5)	(0.4)	(0.3)	(0.2)	(0.1)
Immediate Recognition of LTD Losses (Gains)	0.1	0.1	0.1	0.0	0.0
Total	14.1	13.3	11.9	10.2	9.5

* Numbers may not add due to rounding.

c) No components of annual pension and OPEB costs identified for financial reporting purposes in accordance with US GAAP are excluded from the proposed revenue requirements.

d) Confirmed. The figures for the forecast amortization of actuarial gains and losses for the 2027-2031 period, as attributed to each of OPG's nuclear facilities, OPG's regulated hydroelectric facilities and DNNP LP's facilities, can be found in the response to part b) in the Total sections, under the lines "Amortization of Actuarial Losses (Gains)". Provided below are the figures for the historical periods as attributed to each of OPG's nuclear facilities and OPG's regulated hydroelectric facilities (DNNP LP was not then in existence).

Chart 4
Pension and OPEB Amortization of Actuarial Losses (Gains) for Historical Years – OPG Nuclear

(millions of dollars)	**2020**	**2021**	**2022**	**2023**	**2024**
Pension	129.0	211.5	93.5	0.0	0.0
OPEB	5.7	12.1	5.6	(40.0)	(19.9)
Total	134.7	223.6	99.1	(40.0)	(19.9)

Chart 5
Pension and OPEB Amortization of Actuarial Losses (Gains) for Historical Years – Regulated Hydroelectric

(millions of dollars)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Pension	24.7	22.8	25.6	21.1	21.4	39.4	17.8	0.0	0.0
OPEB	3.0	0.7	1.6	0.7	0.9	2.3	1.1	(7.2)	(3.4)
Total	27.7	23.5	27.2	21.8	22.3	41.7	18.9	(7.2)	(3.4)

Board Staff Interrogatory #236

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1, 3, 5-8
Ref 2: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

Reference 1 presents both forecast accrual costs and forecast cash amounts, as well as the differential between the accrual costs and cash amounts. The exhibit also supports the request for disposition of balances in the various pension and other post-retirement benefits (OPEB) deferral and variance accounts (DVAs).

OPG notes that the operation of these DVAs is discussed in Reference 2, including the continued application of the account that records interest on the difference between pension and OPEB accrual costs and cash amounts.

Question(s):

a) For each historical year for which amounts have been recorded in the applicable pension and OPEB DVAs and are relevant to the balances requested for disposition in this proceeding, please provide a reconciliation of:
   i. The pension and OPEB amounts included in revenue requirement
   ii. the actual accrual costs
   iii. the actual cash funding or cash payment amounts
   iv. the actual amounts recorded in each applicable pension and OPEB variance and deferral account.

b) For each forecast year of 2026-2031, please provide a bridge between:
   i. The pension and OPEB amounts included in the revenue requirement
   ii. The forecast cash funding or cash payment amounts
   iii. The forecast amounts expected to be recorded in the applicable pension and OPEB DVAs.

c) Please explain the key reasons for the differences among the amounts in question a and b, including the extent to which the differences related to accounting treatment, funding valuation methodology, or timing.

d) Please confirm whether the same cost components reflected in forecast revenue requirement are also the basis for determining the actual or forecast amounts recorded in the applicable accounts. If not, please explain the differences.

Response

a) Refer to Ex. H1-1-1, Tables 7, 7a, and 7b that show the calculations of the amounts recorded to OPG's pension and OPEB related deferral and variance accounts (for 2023 and 2024) that are requested for disposition in this proceeding, with reference to the relevant accrual costs and cash amounts. The entries to these accounts have been made in accordance with the EB-2020-0290 Payment Amounts Order.

b) Attachment 1, Tables 1, 1a, and 1b provide the details of the forecast additions to OPG's pension and OPEB related deferral and variance accounts for 2026 in the same manner as Ex. H1-1-1, Tables 7, 7a, and 7b for the actual 2023 and 2024 additions. These 2026 forecast additions are as shown in the continuity schedule for year 2026 forecast deferral and variance account activity provided at Ex. L-H1-Staff-260, Attachment 2, Table 2. Additionally, the details of such actual 2025 additions can be found at Ex. L-H1-Staff-260, Attachment 1, Tables 7, 7a, and 7b. The account entries recorded in 2025 and forecast to be recorded in 2026 in accordance with the EB-2020-0290 Payment Amounts Order.

OPG does not have projections of likely amounts to be recorded in the pension and OPEB related deferral and variance accounts over the 2027-2031 IR term, and is unable to assess a potential range of such amounts at this time, as variances would depend on a host of variables that are outside of OPG's control and are very difficult to predict.

c) With respect to the pension and OPEB accrual costs, which differences are relevant for additions to OPG's Pension and OPEB Cost Variance Account, the key drivers can be found at Ex. F4-3-2, Section 4.3.1.

With respect to the pension and OPEB cash amounts, which differences are relevant for additions to the Pension & OPEB Cash Payment Variance Account, the key driver is the difference in registered pension plan contributions relative to the higher reference amounts that are based on the January 1, 2014 actuarial valuation (for funding purposes) of the registered pension plan that underpinned the regulated hydroelectric revenue requirements approved in the EB-2013-0321 proceeding.

With respect to the differences between pension and OPEB accrual costs and cash amounts, which are relevant for additions to the Pension & OPEB Cash Versus

Accrual Differential Deferral Account and the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account, the key driver is the inherent difference in the constructs that each of these amounts represent. Pension and OPEB accrual costs represent the cost of future benefits earned by employees for providing service in a given period as determined in accordance with US GAAP. The various components of these costs and the key methods and assumptions used to derive them are discussed in Ex. F4-3-2, Section 4.0. Pension and OPEB cash amounts represent, for the registered pension plan, the estimated employer pension plan contributions in accordance with the *Pension Benefits Act* (Ontario) and, for the other benefit plans, amounts paid to retirees, dependents and other beneficiaries in accordance with the provisions of these plans. The components of the registered pension plan contributions and the key methods and assumptions used to derive them are discussed in Ex. F4-3-2, Section 5.0. A further discussion of the differences in material assumptions and methodologies used to determine accrual costs and funding contributions for the registered pension plan can be found at Ex. L-F4-Staff-234. For the other plans, benefit payments in a particular year bear no relationship to the accrual costs for that year.

d) Confirmed.

Board Staff Interrogatory #237

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 4 / Schedule 1 / Table 1
Ref 2: Exhibit F4 / Tab 4 / Schedule 1 / pp. 3-7

Preamble:

At Reference 1, the table shows that nuclear insurance costs are flat from 2020 ($19.5 million) to 2026 ($18.1 million). Then, over the IR term, those costs are forecast by OPG to more than double to $40.7 million by 2031.

At Reference 2, OPG identified two reasons for the forecast increase:

1. An anticipated increase in the current nuclear insurance liability limit under the Nuclear Liability and Compensation Act (NLCA). OPG states, effective 2027, subject to final confirmation by NRCan, the nuclear liability limit is expected to increase from $1 billion to $1.2 billion, for each of Pickering and Darlington, following a five-year NRCan review of the limit.

2. OPG plans to purchase nuclear Business Interruption (BI) insurance for Darlington beginning in 2027 to mitigate the potential loss of earnings and potential impact on OPG's credit ratings in the event of physical damage to the station from a nuclear peril. OPG notes it has not historically procured this coverage.

OPG further notes the BI coverage is not necessary for Pickering until the first unit returns to service and Darlington New Nuclear Program (DNNP) will be insured separately.

In relation to the potential change to the NLCA liability limit, OEB staff reviewed NRCan's Summary of Findings from its Five-Year Review document which notes the following: (1) "An inflation considered value would bring the nuclear third party liability limit to C$1.1 billion."; (2) "Any increase to the liability limit should be phased in gradually …"; and (3) "Internationally the liability limit is increasing with the entry into force of the Amended Paris Convention (2004) in January 2022. This amendment will require that operators in signatory States hold over ~C$1.04 billion." NRCan indicated the current $1 billion was implemented over a three-year phase in period (from $650 million).

Question(s):

a) Please provide a table that shows the forecast increase in costs for each year of 2027 to 2031 attributable to the NLCA and the BI coverage separately.

b) Given NRCan's findings (inflation adjustment to $1.1 billion, gradual phase in, etc.) on the potential change to the NLCA liability limit and the prior phase in to increase it to $1 billion, please explain OPG's anticipated immediate increase to $1.2 billion.

c) In relation to the new BI coverage, please explain why OPG did not consider it to be necessary in the past, but believes it is necessary going forward.

d) Please identify how many times the new BI coverage would have been triggered over the past decade.

e) OPG has indicated its intent to have the BI coverage for all of its nuclear facilities – Darlington, Pickering, DNNP – as they come into service. Table 1 is limited to Darlington and therefore does not reflect what the ultimate full impact would be on consumers. Please provide a table that reflects the cost associated with a hypothetical scenario whereby all the units are in service and have the BI coverage during this IR term (with Darlington, Pickering, and DNNP shown separately). Alternatively, provide a forecast of the cost for when OPG expects all those nuclear units will be in service.

Response

a) The forecasted annual increase in cost for nuclear liability insurance for OPG's nuclear facilities attributed to the expected increase in the nuclear liability limit from $1.0B to $1.2B under the NLCA for each of the Pickering and Darlington stations is as follows from 2027-2031 ($M):

Re: NLCA Limit Increase	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Year-over-Year Incremental Premium Increase	0.0	2.3	0.0	0.1	0.0	0.1
Cumulative Premium Increase Since 2026	0.0	2.3	2.3	2.4	2.4	2.5

The forecasted annual increase in cost attributed to purchasing nuclear business interruption ("BI") insurance coverage for OPG's nuclear facilities is as follows from 2027-2031 ($M):

Re: Addition of Nuclear BI	2026	2027	2028	2029	2030	2031
Year-over-Year Incremental Premium Increase	0.0	8.0	0.2	0.1	0.2	1.2
Cumulative Premium Increase Since 2026	0.0	8.0	8.2	8.3	8.5	9.7

b) OPG, along with the other Canadian nuclear operators, has been in communication with Natural Resources Canada ("NRCan") as NRCan has been completing its five-year review of the nuclear liability limits under the NLCA. NRCan has confirmed to OPG and the other Canadian nuclear operators that the new limit, applicable to each of the Pickering and Darlington stations, is expected to be $1.2B effective January 1, 2027.

c) As stated at Ex. F4-4-1, p. 6, lines 12-18 with respect to nuclear business interruption insurance, "[w]hile it has not historically procured this coverage, OPG considers this to be an appropriate time to add this product as part of its risk management practices in view of the company's evolving financial profile. OPG is facing increased funding needs to meet the forecast capital expenditures, and uninterrupted revenues from electricity generation at Darlington will be a critical source of such cashflow. Should an insurable [nuclear] BI event occur, having the appropriate insurance coverage will be important to mitigating the impact to OPG's funding profile and therefore credit ratings."

The Company's plan to obtain such coverage is also informed by expectations that it would experience a greater revenue loss should an insurable nuclear BI event occur in the absence of such coverage, compared to past periods, due to a higher revenue rate anticipated for nuclear generation as a result of recovering a return of and on the significant investments being made at these facilities. Based on advice received from its insurance broker, OPG understands that other nuclear power generators in Canada specifically purchase nuclear BI coverage.

As noted in part e) below, in addition to the Darlington station, the Applicants have forecasted and plan to purchase nuclear BI for the Pickering station upon the first unit returning to service from refurbishment as well as for the DNNP facilities beginning with the first unit once it is online, for the same reasons as above.

d) Nuclear business interruption insurance provides coverage if there is physical damage from a nuclear incident and to the nuclear island property that results in a business interruption loss. In the past decade, there has not been such an incident at OPG's facilities that OPG expects would have resulted in an insurance recovery had this coverage been in place.

For clarity, OPG's history in the above regard is not a significant consideration in its plans to procure this coverage. Given the high severity of such an insurable event and the operational and safety measures in place at the nuclear plants, both from the standpoint of an insurer and a nuclear operator such as OPG, these incidents are expected to have a low frequency. This is consistent with the general theory of insurance that provides protection against high impact, low likelihood events. If this were a high frequency event, insurers could not provide such coverage.

e) In addition to the Darlington station, the Applicants have forecasted and plan to purchase nuclear BI insurance for the Pickering station upon the first unit returning to service from refurbishment as well as for the DNNP facilities beginning with the first unit once it is online. As such, in addition to the four units at the Darlington station, the requested nuclear revenue requirements reflect the forecasted insurance expense for such coverage for Pickering Unit 5 for the period from May 2031 onwards and for DNNP Unit 1 from October 2030 onwards.

The chart below provides an indicative estimate of the incremental cost associated with nuclear BI insurance for a hypothetical scenario in 2031 where, in addition to the four Darlington units and the one DNNP unit, all four Pickering Units 5-8 are in service for a full year.

Entity	Number of Operating Units	Forecast Cost of Nuclear BI Coverage in 2031 ($M)
OPG	Darlington – 4 Pickering – 4 (hypothetical)	12.6[1] (hypothetical)
DNNP LP	DNNP – 1	3.3

[1] On a standalone basis, the premium expected to be payable for Darlington's nuclear BI coverage represents a minimum premium requirement. As Pickering Units 5-8 return to service from refurbishment and are added to the nuclear BI coverage, the cost of the coverage per unit is expected to reduce.

Society Interrogatory #015

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-222 ie split Term/ETE/PECO Temporary FTE's into Society ETE, PWU term and Other fte's
(2) OPG reply to F4-SUP-14 a) ie update Exhibit F4-3-1, Attachment 1, "Appendix 2K" with 2025 actuals and an updated 2026 forecast.

Question(s):

a) Please update Reference (1) to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available].

b) Update reference (2) with the FTE data provided in a) as well as the corresponding split in compensation for such.

Response

a) and b)

Refer to Ex. L-F4-AMPCO-110 Attachment 1. The latest 2026 projections available in the "Appendix 2K" level of detail are per the budget included in the pre-filed evidence.

Society Interrogatory #016

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-224 ie reconciliation of Exhibit F4-3-1, Attachment 1 staff total for 2024 with Exhibit F4-3-1p8 total for 2024
(2) OPG reply to F4-SUP-14 a) ie update Exhibit F4-3-1, Attachment 1, "Appendix 2K" with 2025 actuals and an updated 2026 forecast.

Question(s):

a) If OPG's reply to reference (1) requires an update to the 2024 data in Exhibit F4-3-1, Attachment 1, please update OPG's reply to reference (2).

Response

a) As explained in Ex. L-F4-Staff-224, the two referenced sources are not equivalent and cannot be reconciled.

Society Interrogatory #018

Interrogatory

Reference:
Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p12

Preamble:

"Willis Towers Watson, consistent with standard methodologies, defines competitive market positioning as +/-10% of the target market position"

Question(s):

a) Is the definition of competitive market positioning as +/-10% of the target market position a definition unique to WTW or is this an industry standard definition?

b) If +/-10% is an industry standard definition please list examples of other companies which use it.

Response

This response was prepared by WTW:

a) The use of a market range when defining compensation competitiveness is consistent with standard methodologies for compensation benchmarking purposes. WTW's standard for position and total organization benchmarking is +/- 10%. Given the limitations inherent in market data sources and the wide range of factors influencing individual compensation levels, it is important to keep in mind that market data reflect an approximation of the overall market for a job. The specific range may vary depending on the circumstances, including the underlying variability in the market data. For example, WTW at times uses a wider range (+/- 15% to +/- 20%) for total direct compensation at executive levels where the underlying variability of the data can be wider. Comparatively, +/- 10% is considered to be a reasonable range, appropriate to the range of positions included in OPG's compensation benchmarking study.

b) Publicly available examples of other companies using +/- 10% of the target market positioning include:
   i. ATCO Electric 2022 Total Remuneration Review prepared by Mercer[1]

[1] 2023-2025 General Tariff Application, Section 1, Appendix 1-B.

ii. Enbridge Gas Inc., 2022 Compensation Benchmarking Review prepared by Mercer[2]
iii. EPCOR Utilities Inc., 2025 Competitive Compensation and Benefits Analysis prepared by WTW[3]
iv. Hydro Ottawa Mercer's Market Compensation Review benchmarking analysis[4].

[2] EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Attachment 1
[3] 2026-2027 General Tariff Application, Appendix G-1
[4] EB-2024-0115, Exhibit 1, Tab 3, Schedule 3, Attachment F

Society Interrogatory #019

Interrogatory

Reference:
Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p7

Question(s):

a) The WTW study report is dated November 2025. Please explain why April 2024 data was used rather than more current information as of April 2025. Would not 2025 data be more relevant to this study and its purpose in this proceeding?

b) When was the April 2024 data available and how many months afterwards did it take for WTW to essentially complete the referenced study? How does this compare to the largely identical WTW study prepared for OPG's EB-2020-0290 evidence?

Response

This response was prepared by WTW:

a) WTW's compensation surveys are conducted from April to August, with an April effective date, and results released in September of the same year. As the report had to be finalized by December 2025 for filing in this proceeding, the 2025 survey results would not have been available with sufficient lead time to complete the required benchmarking, validation, and documentation activities. Accordingly, the study relied on the most recent complete WTW dataset available at the time the analysis was undertaken

b) WTW's 2024 compensation survey results were published and available in September 2024. From that point, WTW required approximately 6 months to complete the analysis and prepare the final report. This overall timing is consistent with the approach applied in the comparable WTW study filed in OPG's EB-2020-0290 proceeding, which similarly relied on the April 2019 survey effective date and the subsequent publication cycle for OPG's payment amounts application filed in December 2020.

Society Interrogatory #020

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p32 Comparator Organizations Non-Executives
(2) EB-2013-0321Decision With Reasons dated November 20, 2014 p75
"The Board finds that Group 2 is the most appropriate comparator for OPG. Group 2 is a small cohort of nuclear related comparators: Atomic Energy of Canada Limited, Bruce Power, Candu Energy Inc., Hydro Quebec, and New Brunswick Power. All are unionized and have or had, in the case of Hydro Quebec nuclear operations."

Question(s):

a) Regarding reference (1), please explain in detail the basis of the selection of these comparator organizations, including why rather than focus on OPG peers in the electricity, nuclear generation and nuclear generation services industries, WTW choose a vast majority of entities in completely unrelated industries. In detail, also please explain why WTW self selected comparator organizations in the:
   i. Transportation industry such as Air Canada, CNR and CPKG.
   ii. Mining industry such as Alcoa, Barrick Gold and Kinross Gold.
   iii. Fossil fuel industry such as Imperial Oil, Irving Oil, Strathcona Resources and Suncor Energy.
   iv. Public Sector organizations focused in totally unrelated areas and services to OPG such as the Business Development Bank of Canada, Export Development Canada, Investment Management Corporation of Ontario, OMERS, Ontario Teachers' Pension Plan Board, OPSEU Pension Trust, Workplace Safety and Insurance Board.

b) Further to reference (1), the majority of OPG staff work in the Greater Toronto Area which has a far greater cost of living than the regions where most of these comparator organizations are located. Did WTW normalize compensation to take into the differing regional costs of living amongst study participants. If not, why not?

c) With regard to reference (2), please explain why WTW choose:
   i. To not include Atomic Energy of Canada Limited and New Brunswick Power in OPG's comparator peer group despite the OEB panel in EB-2013-0321 deciding that they were appropriate comparators.

ii. To include Atkins Realis rather than its subsidiary Candu Energy Inc., which the OEB panel in EB-2013-0321 decided was an appropriate nuclear related comparator for OPG.

Response

This response was prepared by WTW:

a) As part of its updated compensation philosophy, OPG adopted the recommendations regarding peer group criteria outlined at Ex. F4-3-1, Attachment 2, p. 17, as further discussed in Ex. L-F4-CCMBC-008. To determine the organizations to include in the Total Excluding Nuclear Authorized comparator group, WTW applied these criteria against the participants in its 2024 Canadian compensation surveys. The criteria include ownership (corporate structure), size (revenue, assets under management[1]), industry, geography, and complexity. WTW's approach is to take the full list of participants in the survey and apply the comparator group criteria to the organizations. This methodological approach avoids any biased selection of organizations. The organizations included in the comparator group met the comparator group criteria and reflect OPG's market for talent.

i. and ii. These transportation and mining industry organizations have been included based on meeting size, corporate structure and complexity criteria. These organizations also have significant workforces in Ontario with similar skill set requirements (e.g., engineering, project management).

iii. These organizations meet WTW's definition of energy industry organizations and also meet the size, ownership and complexity criteria.

iv. These public sector organizations meet the size criteria and are significant Ontario based organizations, and have been included to meet the 25% general industry weighting criteria, aligned with OPG's compensation philosophy (as outlined in Ex. F4-3-1, Attachment 2, p. 17).

b) Market compensation levels have not been adjusted to reflect regional differences in the cost of living, which is consistent with standard benchmarking methodologies. The comparator groups used in the report reflect the organizations within OPG's talent market and capture the range of companies (in terms of industry and region) from which OPG recruits or loses talent. To the extent that OPG draws talent from a broader labour market (i.e., national), then the market competitive cost of labour

[1] Refer to Ex. L-F4-CCC-090 for discussion of when assets under management criterion is applied instead of revenue.

is national in scope regardless of where the employee is located and / or the specific cost of living in each region.

i. Atomic Energy of Canada Limited and New Brunswick Power Corporation did not participate in WTW's 2024 compensation surveys.

ii. AtkinsRéalis participated in WTW's 2024 compensation survey and provided compensation data for their employees in Candu Energy Inc. as part of their submission.

Society Interrogatory #021

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p32 Comparator Organizations Non-Executives
(2) EB-2021-0110 Exhibit E-6-1 Attachment 1 "Mercer Compensation Benchmarking Study Hydro One Networks" dated 8 July 2021
p3 Table 1 Benchmarking study results
p11 Table 3 Participating Organizations

Preamble:

Comparing the comparator organizations in References 1 and 2, WTW has excluded the following nine companies in the Canadian electricity industry from its study: ATCO Ltd, Toronto Hydro Corporation, Alectra Utilities, SaskPower, Manitoba Hydro, Nalcor Energy, New Brunswick Power, Hydro Ottawa, Elexicon Energy. Note that several of the above companies operate hydroelectric or nuclear generating facilities.

WTW has included 11 companies which were also included in the Reference (2) study along with 44 organizations in completely unrelated industries.

Question(s):

a) Please explain why WTW did not include in its peer group provided in Reference (1) the nine Canadian electricity industry companies listed above which were included in the Reference (2) study.

b) In place of the nine Canadian electricity industry companies listed above which were included in the Reference (2) study, please explain why did WTW substitute in the 44 organizations in completely unrelated industries in its reference (1) study?

c) What would the ballpark impact be on the WTW study in Reference (1) if the 44 organizations in completely unrelated industries mentioned in b) above were eliminated from the results?

Response

This response was prepared by WTW:

a) We note that the Reference (2) study in this question was not a study conducted by WTW, and it was not a study pertaining to OPG. Rather we understand, it was a custom study conducted by Mercer for Hydro One Networks Inc. in connection with its prior rate application and particular to the circumstances of that utility and application. WTW is not familiar with the details of this study. For purposes of the WTW study in this Application, Reference (1) above, please see our response to Ex. L-F4-SUP-020 for details regarding the selection of peer group comparator organizations. Regarding the nine Canadian electricity industry companies listed in this question, they did not participate in WTW's 2024 compensation surveys.

b) Please see our response to part (a) above, and Ex. L-F4-SUP-020 for details regarding the selection of peer group comparator organizations. WTW did not "substitute" companies in place of organizations in the Reference (2) study and we do not agree with the characterization of the organizations in this question. As noted in the response to part (a) above, the Reference (2) study was not conducted by WTW and it was not a study for OPG.

c) WTW disagrees with the characterization of the organizations in this question. The impact of excluding the 44 organizations from the comparator group cannot be accurately estimated. Completing the required analysis would take approximately four to six months, and removing these organizations would substantially reduce the size of the comparator group, resulting in insufficient data for many benchmark roles.

Society Interrogatory #022

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p33 Comparator Organizations Nuclear Authorized- Executives and Non-Executives

Comparator Organizations (3/4)

Nuclear Authorized – Executives and Non-Executives

Comparator Organizations Nuclear Authorized - Executives and Non-Executives (n = 10)	
Bruce Power	FirstEnergy
Dominion Energy	NextEra Energy Inc.
Duke Energy	Public Service Enterprise Group
Entergy	Southern Company Services
Exelon	Tennessee Valley Authority

Percentile Statistics	Revenue ($USD)
75th Percentile	$26,683,500,000
50th Percentile	$14,393,000,000
25th Percentile	$11,692,206,000
Ontario Power Generation	$7,434,000,000
Percent Rank	*4P*

(2) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p5 Comparator Groups - Nuclear Authorized:
- Comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG, including Bruce Power (Canada) and nine U.S.-based nuclear organizations
- These roles require federal licensing, specific education and in-depth knowledge in a unique discipline related to the theories, principles and methods associated with nuclear energy including generation, regulation or training. The requirement to apply this professional body of knowledge represents a significant portion of the job and comparable roles are not readily found in Canada

Question(s):

a) Please explain why Bruce Power was included in the WTW study but not Point Lepreau who have equivalent Canadian nuclear authorized staff and are an ideal comparator for OPG.

b) In reference (2), WTW asserts that the "comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG". However, in terms of size, OPG is in the bottom quartile of this group. How would the study results change if the relatively huge top quartile organizations were eliminated?

c) Please explain why only nuclear organizations of allegedly "comparable size" were used when nuclear authorized staff have similar requirements regardless of size of the organization?

d) Please explain why mainly U.S.-based nuclear organizations were used when there are nuclear authorized staff around the world that could have been used as comparators. Does WTW not have ready access to such information?

Response

This response was prepared by WTW:

a) Bruce Power LP participated in WTW's 2024 compensation surveys. New Brunswick Power Corporation, the operator of the Point Lepreau Nuclear Generating Station, did not participate in WTW's 2024 compensation surveys.

b) and c) These nuclear organizations were selected for consistency with the previous studies in EB-2016-0152 and EB-2020-0290 and therefore the comparator group is unchanged. In 2015, companies for this peer group were selected based on the nuclear generating capacity and not based on revenue, as nuclear generating capacity is a good indicator of organization size and complexity. A minimum of ten organizations is required for a comparator group to conduct a competitive benchmarking analysis. Reducing the size of the organizations (either based on revenue and / or nuclear generating capacity) in the comparator group while maintaining the requisite ten organizations is expected to have a minimal impact on the study results.

c) and d) The comparator group reflects the primary talent market from which OPG recruits and retains nuclear-authorized staff, which is predominantly North America. While WTW conducts compensation surveys globally, combining non-North American data would introduce significant complexity and reduce comparability due to differences in compensation structures, pay levels and mix across jurisdictions.

Society Interrogatory #025

Interrogatory

Reference:
(1) Exhibit F4-3-1, Section 2.0 Overview, p4 lns23-26
"In addition, the compensation established in collective agreements can affect management employees by creating wage compression relative to their represented direct reports. This can result in challenges with internal equity, impede career development and make it more difficult to attract experienced employees into management positions."
(2) Exhibit F4-3-1, Section 6.2.2 Management Salaries, p29 lns8,9
"OPG's ability to successfully deliver on its mandate will depend heavily on the attraction and retention of management talent in a significantly competitive labour market."

Question(s):

a) OPG states that wage compression makes it more difficult to attract experienced employees into management positions. Please provide summary information on the experience profile of individuals appointed to management roles from 2021 through 2025, including:
   i. The average and median years of relevant nuclear industry experience at the time of appointment;
   ii. Whether these roles were filled through internal promotion or external recruitment; and
   iii. The current number of filled and unfilled Band H positions (first level above the Society of United Professionals), and how these vacancies relate to the Company's stated challenges in attracting experienced managers.
   iv. In addition to wage compression, please explain whether other factors affect the ability to attract experienced employees into Band H management positions, including job security, exposure to termination risk, and proximity to retirement, and how these factors have been considered in the Company's management staffing and compensation approach.

Response

a)
   i. Recruitment and selection of candidates is based on the best qualified basis for both internal and external hires. As OPG does not permanently collect such data on an employee's personal work history, the information is not available for aggregation and averaging.

ii. Over the 2021-2025 period, approximately 34% of Band H positions were filled through promotions of internal employees and approximately 25% through external hiring, with the remaining positions filled through other means such as lateral movements.

iii. Currently, there are approximately 25 Band H unfilled vacancies. These vacancies are primarily in project management and IT roles, areas where OPG competes for management talent with companies across Canada and the US.

iv. As outlined at Ex. F4-3-1, p. 30, there have been both non-compensation and compensation-related initiatives implemented to help retain and attract qualified management employees. As a result, there has been an approximately 30% increase in Society-represented employees moving into management roles over the 2021-2025 period. However, externally, compensation remains the top reason offers are declined. OPG recognizes that each employee has their own evolving personal goals as it relates to career and skill development and is not able to infer as to what each individual might consider.