ONTARIO POWER GENERATION

Andrea Brown
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July 17, 2026

VIA RESS AND EMAIL

Mr. Ritchie Murray
Registrar
Ontario Energy Board
27th Floor - 2300 Yonge Street
Toronto, Ontario M4P 1E4

Dear Mr. Murray:

Re: EB-2025-0297 Application by Ontario Power Generation Inc. and DNNP LP by its general partner, DNNP GP Inc., (together, the "Applicants") for an order or orders relating to payment amounts for prescribed generating facilities (the "Application") – Corrections

Enclosed are corrections to the Applicants' pre-filed evidence and interrogatory responses. The Applicants will submit these documents through the Regulatory Electronic Submissions System. This material will also be available on OPG's website at www.opg.com.

A detailed description of the corrections and clarifications to evidence and interrogatory responses is provided in Attachment 1.

These corrections do not have an impact on approvals sought in the Application.

Should the OEB require any further information or clarification, please do not hesitate to let me know.

Respectfully submitted,

A.Brown

Andrea Brown

cc:
Aimee Collier (OPG) via e-mail
Charles Keizer (Torys LLP) via e-mail

Attachment 1

Corrections to Pre-filed Evidence and Interrogatories

#	Exhibit	Description of the Change
1.	Ex. L-A1-CCC-001	• Attachment 1, Tables 38, 39, 49, 50, 51, and 53: numerical corrections for 2025 Actual DNNP facilities FTEs and for corporate allocated FTEs and costs.
2.	Ex. L-A1-CCC-010	• Response to part b): added sentence to indicate the transfer of OPG's ownership interest in DNNP LP to OPG's wholly owned subsidiary, OPG Financing LP. • Response to part c): deletion of the first sentence that was part of the original response when the requested information referenced was previously not yet available.
3.	Ex. L-A1-CCC-011	• Added "and c)" to the part b) response.
4.	Ex. L-A1-SEC-017	• Page 1, line 32: editorial correction to indicate the response was prepared by London Economics International.
5.	Ex. L-A1-Staff-275	• Page 12, line 8: editorial correction to indicate expenses in Chart 6 are related to income tax, not OM&A. • Chart 6: corrected row descriptions to reflect that the income tax expense details relate to 2027 only.
6.	Ex. B1-1-1	• Page17, line 26: editorial correction adding the word 'also'. • Page 18, line 4: numerical reference correction for OPG's nuclear forecasted rate base.
7.	Ex. L-C1-SEC-035	• Attachment 1 (Confidential): correction to the left side credit metrics graph for a formulaic error.
8.	Ex. L-C1-Staff-029	• Page 5: deletion of an inadvertently placed hyperlink.
9.	Ex. L-D2-AMPCO-073	• Correction to reference information provided subsequent to Motions Resolution filed on May 4, 2026.
10.	Ex. L-D2-SEC-089	• Page 1: correction to reference information provided subsequent to Motions Resolution filed on May 4, 2026.

11.	Ex. L-D2-SEC-097	• Part b): correction to reference information provided subsequent to Motions Resolution filed on May 4, 2026.
12.	Ex. L-D3-SEC-125	• Attachment 1, p. 1, lines 17 and 29: numerical corrections to 2024 Plan capital expenditures. • Attachment 1, p. 2, lines 24 and 36: numerical corrections to 2024 Plan capital expenditures.
13.	Ex. L-D3-SEC-126	• Page 1, line 24: correction to variance percentage. • Attachment 1, p. 1, line 8: numerical corrections for 2023 business plan amount and related footnote. • Attachment 1, p. 2, lines 4, 10: numerical corrections for 2023 business plan amounts. • Attachment 1, p. 2, line 38: numerical correction for 2024.
14.	Ex. L-E1-SEC-132	• Chart 1: consistent with the response provided in JT1.21, corrected values for 2026 and 2027 export revenue and added lines for Other Non-OPG Cost and OPG Biomass Cost.
15.	Ex. L-E2-SEC-137	• Attachment 1: certain editorial corrections to notes, aligning with JT3.20, Attachment 1
16.	Ex. L-E1-Staff-148	• Chart 1: corrected amount for CMSC payment received in 2025 (Jan-Apr) based on error noted in JT1.3.
17.	Ex. E2-1-2	• Page 4, line 6: editorial addition for the word ‘primarily’
18.	Ex. L-F4-AMPCO-117	• Attachment 1: filed a pdf version of the Excel attachment.
19.	Ex. F4-2-1	• Page 19, line 10-13: revision to clarify the interaction of CEITCs with undepreciated capital cost under the income tax legislation. • Table 3g: correction to notes numbering on lines 9, 10, 16 and 18. • Table 3i: editorial correction in note 5 that clarifies the tax treatment for DNNP facilities.
20.	Ex. F4-CCC-084	• Table 32: correction to notes numbering on lines 9, 10, 16 and 18

		• Table 34: editorial correction in note 5 that clarifies the tax treatment for DNNP facilities.
21.	Ex. F4-SEC-200	• Corrected values for OPG weighted average capital cost allowance rates
22.	Ex. H1-1-1	• Attachment 9: corrected to reflect the income tax impact of 77.5% attributable to taxable partners, rather than 100%.
23.	Ex. L-H1-SEC-204	• Attachment 1, p. 5: editorial clarification in the illustrative accounting order for the Payment Amount Shaping Deferral Account to indicate that a nil balance is to remain in the account at the end of the deferral period excluding interest.
24.	Ex. L-H1-Staff-055	• Response to part c): editorial addition to clarify the scope of bill impact analysis presented.
25.	Ex. L-H1-Staff-257	• p.3, lines 5-9: correction to align with previously corrected statement in Ex. H1-1-1, p.61, lines 7-8.

Table 38
Operating Costs Summary - OPG Nuclear Facilities ($M)

Line No.	Cost Item	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)
	OM&A:												
1	**OPG Nuclear Facilities Base OM&A**	1,313.9	1,316.0	1,305.7	1,418.9	1,433.5	1,250.3	1,210.2	840.4	850.7	898.4	916.8	1,225.4
2	**OPG Nuclear Facilities Project OM&A**	99.5	111.6	89.5	141.1	107.9	63.1	73.3	76.1	82.4	84.0	84.8	83.2
3	**OPG Nuclear Facilities Outage OM&A**	293.9	382.8	265.0	318.1	358.1	141.1	209.4	223.7	112.7	219.1	121.6	142.2
4	**Pickering Cyclical Maintenance OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	25.0	168.4	160.9	168.9	169.9	106.6
5	**Subtotal OPG Nuclear Facilities OM&A**	1,707.3	1,810.4	1,660.2	1,878.1	1,899.5	1,454.5	1,517.8	1,308.6	1,206.7	1,370.4	1,293.2	1,557.4
6	**Darlington Refurbishment OM&A**	19.0	35.6	22.3	39.0	59.7	10.9	1.5	0.0	0.0	0.0	0.0	0.0
7	**Darlington New Nuclear OM&A**[1,3]	13.1	95.4	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**DNNP Operational Readiness**	0.0	0.0	0.0	1.1	2.3	13.4	0.0	0.0	0.0	0.0	0.0	0.0
9	**Other New Nuclear OM&A**[2,3]	0.0	0.0	0.0	7.6	15.1	39.4	136.4	0.0	0.0	0.0	0.0	0.0
10	**Pickering Refurbishment Feasibility Study**[3]	0.0	0.0	0.2	17.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Pickering Refurbishment OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	4.2	100.3	94.1	84.9	52.7	46.5
12	**Allocation of Corporate Costs**[4]	352.7	359.7	366.2	406.3	400.8	410.8	416.1	417.5	412.1	432.7	444.7	471.6
13	**Allocation of Centrally Held Costs**	215.0	209.3	76.3	(18.5)	104.7	55.6	(47.2)	(35.4)	(30.8)	(60.1)	(33.3)	(21.6)
14	**Asset Service Fees**	55.6	65.0	71.1	74.3	77.1	85.4	93.3	72.7	73.9	89.5	99.0	99.4
15	**Subtotal Other OM&A**	655.3	765.1	538.5	527.6	659.8	615.4	604.2	555.1	549.3	547.0	563.1	596.0
16	**Total OPG Nuclear Facilities OM&A**	2,362.6	2,575.5	2,198.7	2,405.7	2,559.3	2,069.9	2,122.1	1,863.7	1,756.0	1,917.4	1,856.3	2,153.5
17	**OPG Nuclear Facilities Fuel Costs**	234.9	232.0	222.5	218.4	211.8	258.6	239.2	150.9	221.7	223.6	261.2	306.1
	Other Operating Cost Items:												
18	**Depreciation and Amortization**	448.6	504.8	626.6	685.6	753.7	546.9	617.7	663.3	708.5	730.3	779.8	992.6
19	**Income Tax**	158.6	(20.2)	81.0	83.5	(59.9)	237.9	(36.9)	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
20	**Property Tax**	11.1	11.6	11.8	12.1	12.6	14.6	13.5	14.0	14.2	14.5	14.8	15.0
21	**Total OPG Nuclear Facilities Operating Costs**	3,215.8	3,303.7	3,140.6	3,405.4	3,477.5	3,128.0	2,955.6	2,675.2	2,683.8	2,869.1	2,895.5	3,450.6

Notes:

1 For amounts in 2020 to 2022 refer to EB-2023-0336, Ex. H1-1-1, Table 20, line 2.

2 Actual and budget amounts in the Other New Nuclear OM&A category primarily relate to impact assessment preparation for potential new nuclear generation at OPG strategic sites. No amounts related to new nuclear generation projects is included in the revenue requirement for OPG's nuclear facilities.

3 Refer to Ex. F2-1-1, Section 5.0.

4 The correction made to 2025 Actual amounts for the Allocation of Corporate Costs similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, and Ex. F4-Staff-228.

Table 39

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)
	OPG Nuclear Facilities OM&A:												
1	**Regular Staff**	4,379.4	4,038.8	3,652.6	3,793.0	4,096.2	3,952.2	3,967.1	3,141.6	3,126.3	3,144.7	3,147.0	3,761.6
	Non-Regular Staff												
2	Term and Extended Temporary	584.7	766.7	887.0	927.0	599.2	237.8	174.7	0.0	0.0	0.0	0.0	0.0
3	Temporary	766.7	812.6	577.6	582.7	525.5	391.4	322.4	162.7	143.5	197.3	148.2	150.0
4	EPSCA	76.7	94.2	99.3	88.2	100.0	50.8	25.4	22.0	21.6	21.6	21.0	20.0
5	**Total Non-Regular Staff**	1,428.1	1,673.5	1,563.9	1,597.9	1,224.7	680.1	522.6	184.7	165.1	218.9	169.2	170.0
6	**Subtotal OPG Nuclear Facilities OM&A**	5,807.5	5,712.3	5,216.5	5,390.9	5,320.9	4,632.4	4,489.7	3,326.3	3,291.4	3,363.5	3,316.1	3,931.6
	OPG Nuclear Facilities Capital:												
7	**Regular Staff**	221.8	179.3	190.9	202.0	249.7	302.5	440.7	469.0	459.8	459.5	472.0	477.4
	Non-Regular Staff												
8	Term and Extended Temporary	5.2	11.7	20.0	25.7	25.1	10.2	17.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	51.1	32.0	18.8	2.0	7.0	33.8	94.1	59.0	57.5	40.2	38.5	35.5
10	EPSCA	26.0	32.7	45.5	47.1	42.6	38.4	28.2	22.4	17.8	7.8	7.0	7.0
11	**Total Non-Regular Staff**	82.2	76.4	84.3	74.7	74.7	82.4	139.3	81.4	75.3	48.0	45.5	42.5
12	**Subtotal OPG Nuclear Facilities Capital**	304.0	255.6	275.2	276.7	324.3	384.9	580.0	550.4	535.2	507.5	517.5	519.9
	Darlington Refurbishment Program:												
13	**Regular Staff**	432.5	394.0	404.0	446.7	499.9	440.0	55.8	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
14	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Temporary	117.0	83.3	69.7	67.2	69.2	41.7	21.6	0.0	0.0	0.0	0.0	0.0
16	EPSCA	128.6	224.2	252.2	295.1	271.1	221.0	29.3	0.0	0.0	0.0	0.0	0.0
17	**Total Non-Regular Staff**	245.6	307.4	321.9	362.3	340.4	262.8	50.9	0.0	0.0	0.0	0.0	0.0
18	**Subtotal Darlington Refurbishment**	678.2	701.5	725.9	809.0	840.3	702.8	106.7	0.0	0.0	0.0	0.0	0.0
	Pickering Refurbishment Program:												
19	**Regular Staff**	0.0	0.0	0.0	7.6	159.5	455.6	1,177.1	2,258.9	2,281.1	2,306.0	2,265.0	1,623.7
	Non-Regular Staff												
20	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.8	7.0	21.3	7.0	7.0	7.0		
21	Temporary	0.0	0.0	0.0	0.1	10.3	31.5	128.5	29.0	13.0	13.0	20.0	20.0
22	EPSCA	0.0	0.0	0.0	0.1	3.2	21.2	109.7	350.2	473.4	419.0	335.0	252.9
23	**Total Non-Regular Staff**	0.0	0.0	0.0	0.1	14.3	59.7	259.4	386.2	493.4	439.0	355.0	272.9
24	**Subtotal Pickering Refurbishment Program**	0.0	0.0	0.0	7.8	173.8	515.3	1,436.5	2,645.1	2,774.4	2,745.0	2,620.0	1,896.6
	DNNP Facilities Capital:												
25	**Regular Staff**[1]	0.0	0.0	73.9	107.0	139.7	153.8	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
26	Temporary[1]	0.0	0.0	5.4	9.1	10.4	10.4	0.0	0.0	0.0	0.0	0.0	0.0
27	EPSCA	0.0	0.0	0.0	0.2	0.1	0.3	0.0	0.0	0.0	0.0	0.0	0.0
28	**Total Non-Regular Staff**	0.0	0.0	5.4	9.3	10.4	10.7	0.0	0.0	0.0	0.0	0.0	0.0
29	**Subtotal DNNP Facilities Capital**	0.0	0.0	79.3	116.3	150.1	164.5	0.0	0.0	0.0	0.0	0.0	0.0
	Darlington & Other New Nuclear OM&A:												
30	**Regular Staff**	5.9	44.3	4.8	21.9	27.2	35.9	95.1	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
31	Temporary	0.6	2.0	2.6	0.6	1.3	3.0	0.0	0.0	0.0	0.0	0.0	0.0
32	EPSCA	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Total Non-Regular Staff**	0.6	2.2	2.7	0.6	1.3	3.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**Subtotal Darlington & Other New Nuclear**	6.5	46.5	7.5	22.5	28.5	38.9	95.1	0.0	0.0	0.0	0.0	0.0
	Nuclear Provision:												
35	**Regular Staff**	332.4	344.0	359.6	400.5	537.9	830.3	794.7	725.1	696.9	603.9	609.0	610.7
	Non-Regular Staff												
36	Term and Extended Temporary	8.3	16.1	20.2	33.0	31.1	21.0	2.3	0.0	0.0	0.0	0.0	0.0
37	Temporary	45.7	51.3	49.6	48.7	48.1	63.6	42.2	31.0	29.3	24.0	24.0	24.0
38	EPSCA	3.0	4.4	4.1	4.0	10.2	45.6	2.3	2.3	2.2	2.0	2.0	2.0
39	**Total Non-Regular Staff**	57.0	71.9	73.9	85.6	89.4	130.2	46.7	33.3	31.5	26.0	26.0	26.0
40	**Subtotal Nuclear Provision**	389.4	416.0	433.4	486.1	627.3	960.5	841.5	758.4	728.4	629.9	635.0	636.7
	OPG Nuclear Non-Energy Direct:												
41	**Regular Staff**	17.7	20.3	45.1	41.8	40.1	45.7	35.9	39.0	39.0	39.0	39.0	39.0
	Non-Regular Staff												
42	Term and Extended Temporary	0.7	0.4	0.9	2.9	1.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0
43	Temporary	1.1	0.8	0.6	1.9	0.8	0.5	0.0	0.0	0.0	0.0	0.0	0.0
44	EPSCA	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 Non-Regular Staff**	1.8	1.2	1.5	4.8	2.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0
46	**Subtotal OPG Nuclear Non-Energy Direct**	19.5	21.5	46.6	46.6	42.1	46.9	35.9	39.0	39.0	39.0	39.0	39.0
47	**Total OPG Nuclear Facilities**	7,205.1	7,153.4	6,784.4	7,155.9	7,507.3	7,446.0	7,585.4	7,319.2	7,368.4	7,284.9	7,127.7	7,023.8

1 The correction made to 2025 Actual amounts for the DNNP Facilities similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, and Ex. F4-Staff-228.

Table 49

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities ($M)[1]

Line No.	Corporate 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)
	Base OM&A												
1	Corporate & Technology Services[3]	130.1	139.6	144.5	145.4	157.9	159.2	152.3	149.6	154.5	164.4	172.8	191.5
2	Real Estate[2]	49.3	47.3	42.2	52.7	49.4	49.7	51.0	55.0	55.2	58.5	59.3	60.5
3	Supply Chain	44.2	43.0	45.8	52.5	51.4	42.3	44.3	44.6	41.9	43.6	43.9	50.4
4	Finance	27.2	26.7	29.1	33.4	31.2	37.3	38.4	38.0	38.5	40.9	41.4	42.5
5	Human Resources	24.5	24.8	28.1	37.3	32.2	30.3	30.2	26.4	27.2	28.4	28.7	31.2
6	Corporate Centre	34.1	34.0	31.0	32.8	33.7	43.9	40.4	38.5	37.2	39.8	42.1	42.3
7	**Total Base OM&A**	309.4	315.3	320.8	354.1	355.8	362.6	356.6	352.1	354.6	375.5	388.2	418.3
8	**Leases & Utilities**	22.7	22.5	23.1	22.9	20.8	23.3	21.9	25.8	21.1	20.9	20.9	20.5
9	**Project OM&A**	20.6	21.9	22.3	29.3	24.3	24.8	37.6	39.6	36.5	36.3	35.6	32.8
10	**Total OM&A**	352.7	359.7	366.2	406.3	400.8	410.8	416.1	417.5	412.1	432.7	444.7	471.6

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

3 The correction made to 2025 Actual amounts for the Allocation of Corporate Costs similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, Ex. F4-Staff-228, Ex. F3-VECC-013, Attachment 1, Ex. F3-VECC-014, Attachment 1 and Ex. F4-SUP-014, part e) and Attachment 1.

Table 50

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities - Darlington ($M)[1]

Line No.	Corporate 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)
	Base OM&A												
1	Corporate & Technology Services[3]	62.9	65.6	67.6	69.7	75.8	78.0	69.0	73.3	74.7	80.0	83.2	87.5
2	Real Estate[2]	23.2	23.0	20.2	27.9	26.8	29.1	31.5	33.0	33.0	34.4	34.8	35.8
3	Supply Chain	20.1	19.8	19.9	23.1	23.1	22.2	21.8	25.3	23.5	24.3	24.3	26.8
4	Finance	15.8	16.3	17.3	18.0	16.6	19.7	18.0	17.1	15.8	16.1	14.7	15.9
5	Human Resources	11.7	12.7	14.1	17.4	15.9	16.3	14.4	12.6	12.5	12.8	12.9	13.8
6	Corporate Centre	19.3	21.0	17.5	18.4	17.4	23.2	19.0	17.4	15.4	15.9	15.2	16.0
7	**Total Base OM&A**	153.0	158.3	156.6	174.5	175.6	188.5	173.8	178.6	174.9	183.5	185.1	195.7
8	**Leases & Utilities**	11.1	11.8	11.8	11.0	10.3	12.9	11.2	13.4	10.9	10.8	10.7	10.6
9	**Project OM&A**	11.1	12.2	10.8	13.7	11.0	12.1	15.6	21.8	20.0	20.6	18.8	16.2
10	**Total OM&A**	175.2	182.3	179.2	199.2	196.9	213.5	200.6	213.7	205.8	214.9	214.6	222.4

Notes:
1. Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.
2. Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).
3. The correction made to 2025 Actual amounts for the Allocation of Corporate Costs similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, Ex. F4-Staff-228, Ex. F3-VECC-013, Attachment 1, Ex. F3-VECC-014, Attachment 1 and Ex. F4-SUP-014, part e) and Attachment 1.

Numbers may not add due to rounding.

Table 51

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities - Pickering ($M)[1]

Line No.	Corporate 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)
	Base OM&A												
1	Corporate & Technology Services[3]	67.2	74.0	76.9	75.7	82.1	81.2	83.3	76.3	79.9	84.3	89.6	104.1
2	Real Estate[2]	26.0	24.3	22.0	24.9	22.6	20.6	19.5	22.0	22.3	24.1	24.5	24.7
3	Supply Chain	24.1	23.2	25.9	29.4	28.3	20.1	22.5	19.3	18.3	19.2	19.6	23.6
4		11.4	10.4	11.8	15.4	14.7	17.6	20.3	20.9	22.7	24.8	26.7	26.6
5	Human Resources	12.8	12.1	14.0	19.8	16.3	13.9	15.8	13.8	14.7	15.6	15.8	17.4
6	Corporate Centre	14.8	13.0	13.6	14.4	16.2	20.7	21.4	21.1	21.8	24.0	26.9	26.3
7	**Total Base OM&A**	156.4	157.0	164.2	179.6	180.2	174.1	182.7	173.5	179.7	192.0	203.1	222.7
8	**Leases & Utilities**	11.6	10.7	11.3	11.9	10.4	10.4	10.7	12.4	10.2	10.1	10.2	10.0
9	**Project OM&A**	9.5	9.7	11.5	15.6	13.3	12.7	22.0	17.8	16.5	15.7	16.9	16.5
10	**Total OM&A**	177.5	177.4	187.0	207.1	203.9	197.2	215.5	203.7	206.4	217.8	230.1	249.1

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

3 The correction made to 2025 Actual amounts for the Allocation of Corporate Costs similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, Ex. F4-Staff-228, Ex. F3-VECC-013, Attachment 1, Ex. F3-VECC-014, Attachment 1 and Ex. F4-SUP-014, part e) and Attachment 1.

Numbers may not add due to rounding.

Table 53
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**[1]	854.9	799.2	880.2	1,049.6	1,124.5	1,066.5	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[1]	146.9	156.0	168.5	186.2	152.1	128.7	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	187.0	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	1,253.5	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	1,574.0	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4

1 The correction made to 2025 Actual amounts for the Allocation of Corporate Costs similarly applies to Ex. F4-CCC-089, Ex. F2-Staff-202 part c), Ex. F4-AMPCO-110, Attachment 1, Ex. F4-Staff-228, Ex. F3-VECC-013, Attachment 1, Ex. F3-VECC-014, Attachment 1 and Ex. F4-SUP-014, part e) and Attachment 1.

CCC Interrogatory #010

Interrogatory

Reference:
Exhibit A1, Tab 4, Schedule 4, pp. 2-3, 10

Question(s):

a) Please file the following agreements:

   i. DNNP LP and OPG Lease Agreement
   ii. DNNP LP and OPG Reimbursement Agreement
   iii. DNNP LP and OPG PMA
   iv. DNNP LP and OPG MOMA

b) Please further explain the conditions that must be satisfied in order for CGF and BOF to acquire minority interests in DNNP LP.

c) To the extent that it is available, please file the "audited schedule of costs that is approved by Ontario Power Generation Inc.'s board of directions as at the transfer date" regarding the assets to be transferred from OPG to DNNP LP (which will be considered the opening CIP balance for DNNP LP).

d) Please further explain the statement that "DNNP LP will reimburse OPG for all construction in progress costs through the issuance of ownership units."

Response

a) The Applicants attach the following agreements between OPG and DNNP LP:
   - Attachment 1 (confidential): DNNP LP and OPG Lease Agreement
   - Attachment 2: DNNP LP and OPG Reimbursement Agreement
   - Attachment 3 (confidential): DNNP LP and OPG Development and Construction Project Management Agreement ("PMA")
   - Attachment 4 (confidential): DNNP LP and OPG Management, Operations, Maintenance and Administration Services Agreement ("MOMA")
   - Attachment 5: DNNP LP and OPG IESO Payments Collection, Allocation and Settlement Agreement
   - Attachment 6: DNNP LP and OPG Intellectual Property Rights Agreement.
   - Attachment 7 (confidential): Contribution Agreement

b) On April 20, 2026, Canada Growth Fund, through its subsidiaries, Renaissance Power 2025-1 Inc. and Renaissance Power 2025-2 Inc., and Building Ontario Fund, through its subsidiary BOF DNNP Limited, acquired minority ownership in DNNP LP equal to 15% and 7.5%, respectively. The closing conditions have been satisfied. In conjunction with the above, OPG transferred its ownership interest in DNNP LP to a wholly owned subsidiary, OPG Financing LP.

c) Refer to Attachment 8 for the referenced audited schedule of costs. Additionally, Attachment 9 provides DNNP LP’s audited financial statements as at December 31, 2025.

d) Unlike Canada Growth Fund and Building Ontario Fund, OPG did not inject cash to acquire its initial ownership units in DNNP LP. OPG instead contributed the Darlington New Nuclear Program (“DNNP”) construction work as its initial contribution, valued at the cost of such work to OPG as at December 31, 2025, as set out in Schedule A of the Reimbursement Agreement, together with the $1000 transfer value specified in Attachment 7, section 5. For clarity, it is this reimbursement of OPG’s construction work in progress, as set out in the audited schedule of costs in Attachment 8, that comprises DNNP LP’s opening construction work in progress balance, as also set out in the DNNP LP’s audited financial statements as at December 31, 2025 in Attachment 9, that the OEB must accept among DNNP LP’s capital costs under Ontario Regulation 53/05, section 14(2)2(i).

CCC Interrogatory #011

Interrogatory

Reference:
Exhibit A1, Tab 4, Schedule 4, Attachment 1, pp. 1-3

Question(s):

a) Please confirm, or correct, that the total cost for the four unit DNNP is expected to be approximately $21 billion (with $7.7 billion associated with Unit 1 and the common facilities).

b) Please provide a table showing both the costs and benefits of SMR technology relative to other traditional forms of nuclear generation.

c) Please provide the relevant reports, documents, and memos that explain the initial decision to move forward with the DNNP.

Response

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

a) As referenced in Ex. D2-4-8, Attachment 1, the Class 3 estimate to complete design, procurement, construction and commissioning of DNNP Unit 1, including site scope common to the four-unit program, is $7,698M. The current class 4 four-unit program estimate is $20,949M for the DNNP.

b) and c)
The DNNP forms part of the Province of Ontario's integrated energy plan ("IEP") which is the Government of Ontario's plan to ensure it can meet growing electricity needs for the period specified by the plan. As the OEB stated in EB-2020-0290:

> The OEB's role in this proceeding is distinct from the IESO and the OEB is not the system planner. As such, the OEB does not have the mandate or authority to consider or adjudicate on analyses and proposals respecting generating asset mixes for the Ontario electricity market in this proceeding.[1]

[1] Procedural Order No. 2 and Decision on Motion, EB-2020-0290, April 29, 2021, p. 5.

Therefore, it is not within the jurisdiction of the OEB to be the electricity system planner and consider alternatives to projects such as the DNNP forming part of the IEP. The OEB's jurisdiction is limited to considering the reasonableness and prudence of the costs of the project in question for purposes of establishing rates. As such, the question posed is not relevant to these proceedings.

Refer to Ex. L-D2-SEC-098, Attachment 1 (confidential), which has been provided pursuant to the Motions Resolutions letter filed on May 4, 2026.

SEC Interrogatory #017

Interrogatory

Reference:
A1-3-2, Attachment 1

Question(s):

With respect to the LEI, *Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business* Report.

a) [p.11] Please describe the extent to which each of the cited precedents includes regulated hydroelectric assets. If the cited precedents include significantly less hydroelectric assets than OPG's regulated hydroelectric business, please discuss how that fact should be taken into account in assessing the relevance of each of the cited precedents.

b) [p.14] Please discuss the reasons for the volatility of capital cost indices.

c) [p.22] Please provide whatever information is available on the reasons why OPG's indicative labour cost growth has substantially exceeded AWE growth over the 22-year comparison period.

d) [p.29] Please explain why trends in the value of existing capital assets and the value of the services they provide would be relevant to the inflation impact on the cost of new capital assets.

Response

This response was prepared by London Economics International ("LEI").

a) LEI understands the term "cited precedents" in the question to refer to the content on slides 11 and 13 of the inflation factor report. On slide 11, LEI listed recent decisions by regulators across Canada that applied several inflation factor evaluation criteria – including: (i) relevance to utility costs, (ii) exogeneity, (iii) source reliability, (iv) data availability, (v) precedence and simplicity, and (vi) index stability. On slide 13, LEI listed examples of the inflation indices recently approved by other regulators.

None of the examples cited on these slides are directly related to the regulated hydroelectric business. However, these examples all relate to regulated utility businesses, and demonstrate the application of the aforementioned evaluation criteria by regulators as they consider appropriate measures of inflation. These evaluation criteria are relevant regardless of the regulated utility business in question.

b) As noted on slide 26 of LEI's inflation factor report, capital-specific indices tend to be more volatile due to their sensitivity to economic cycles. In fact, the OEB has expressed concerns with volatility of the capital input measure and refrained from using it again for this reason:

> "The 3-factor IPI included capital, labour, and nonlabour indices. However, the Board and many stakeholders were concerned that the resulting numbers generated do not appear reasonable and result in unacceptable volatility. … The primary source of volatility in the 3-factor IPI is the capital sub-index."

c) Statistics Canada's AWE index (Ontario, industrial aggregate excluding unclassified businesses) is a broad index that includes data on labour costs from a range of industries:

- Forestry, logging and support
- Mining, quarrying, and oil and gas extraction
- Utilities
- Construction
- Manufacturing
- Trade
- Transportation and warehousing
- Information and cultural industries
- Finance and insurance
- Real estate and rental and leasing
- Professional, scientific and technical services
- Management of companies and enterprises
- Administrative and support, waste management and remediation services
- Educational services
- Health care and social assistance
- Arts, entertainment and recreation
- Accommodation and food services
- Other services (except public administration)
- Public administration

In contrast, OPG's workforce includes highly technical and specialized individuals, as well as unionized employees. LEI theorizes that these factors contribute to OPG's higher labour cost growth.

d) LEI is recommending an inflation factor that would be applicable to the total revenue requirement, not just the "cost of new capital assets" as implied in the question. As part of the consideration of capital-related inflation indices, slide 29 of LEI's inflation factor report presents a theoretical model for capturing the inflationary pressures on capital assets known as the implicit rental price of capital, which reflects the cost of using capital over time and incorporates key economic variables such as depreciation, inflation, the cost of capital, and tax effects.

Board Staff Interrogatory #275

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Chart 1
Ref 2: Exhibit I1 / Tab 1 / Schedule 1 / Table 1
Ref 3: Exhibit I1 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG summarizes the Hydroelectric Custom IR Framework.

Reference 2 provides a breakdown of the 2027 test year revenue requirement.

Reference 3 provides the 2027 revenue requirement with 2028 to 2031 revenue requirements the purpose of calculating the proposed Capital Factor in each of 2028 to 2031.

For the purpose of illustrating the relationship between deferral and variance accounts (DVAs) and Custom IR revenue requirements in each of the years 2027 to 2031, please answer the following questions.

Question(s):

a) Please list all DVAs, either existing or proposed that relate to the capital related revenue requirement due to 2027 to 2031 in-service additions. Further, please provide an annual breakdown of the capital related revenue requirement in each of 2027 to 2031 for the following categories of rate base by completing the following table:
   i. Rate base as at the end of 2026
   ii. In-service additions over the 2027 to 2031 where variances relate to the identified deferral and variance accounts
   iii. In-service additions over the 2027 to 2031 period where no DVA would track and variances.

Table 1: Capital Related Revenue Requirement Details

$ million	2027	2028	2029	2030	2031
For rate base as at the end of 2026					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					

$ million	2027	2028	2029	2030	2031
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to rate base as at the end of 2026					
For 2027 to 2031 in-service additions where variances will be tracked in DVAs					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions that are captured in DVAs					
For 2027 to 2031 in-service additions where there are no DVAs that would track variances					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions where there is no DVA for variances					

b) Please list all DVAs that would track variances to OM&A expenses for 2027 to 2031. Similar to above, please provide a breakdown of those OM&A expenses by completing the following table:

Table 2: OM&A Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 OM&A where variances will be tracked in DVAs					
Base OM&A					
Project OM&A					
Outage OM&A					
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					

$ million	2027	2028	2029	2030	2031
Any other OM&A Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 OM&A Expense that are captured in DVAs					
2027 to 2031 OM&A where there are no DVAs that would track variances					
Base OM&A					
Project OM&A					
Outage OM&A					
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					
Any other OM&A Expense where there is no DVA to track variances					
Total Revenue Requirement Impact from 2027-2031 OM&A where there is no DVA for variances					

c) Please list all DVAs that would track variances to gross revenue charges (GRC) Expense for 2027 to 2031. Please confirm that it is OPG's proposal that 100% of the GRC Expense would be subject to DVAs. If not confirmed, please complete the following table:

Table 3: Fuel Expense Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Fuel Expense where variances will be tracked in DVAs					
GRC Expense					
Any other Fuel Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Fuel Expense that are captured in DVAs					
2027 to 2031 Fuel Expense where there are no DVAs that would track variances					
GRC Expense					
Any other Fuel Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Fuel Expense where there is no DVA for variances					

d) Please list all DVAs that would track variances to Property Tax expenses for 2027 to 2031. Similar to above, please provide a breakdown of those Property Tax expenses by completing the following table:

Table 4: Property Tax Details

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense that are captured in DVAs					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

e) Please list all DVAs that would track variances to Other Revenues from 2027 to 2031. Similar to above, please provide a breakdown of those Other Revenues by completing the following table:

Table 5: Other Revenue Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Other Revenue where variances will be tracked in DVAs					
Ancillary Services					
Segregated Mode of Operation					
Water Transactions					
Capacity Exports					
Hydroelectric Incentive Mechanism (HIM) Revenue					
Any additional Other Revenues where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Other Revenues that are captured in DVAs					
2027 to 2031 Property Tax Expense where there are no DVAs that would track variances					
Ancillary Services					
Segregated Mode of Operation					
Water Transactions					
Capacity Exports					
HIM Revenue					
Any additional Other Revenues where there are no DVAs to track variances					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

f) Please list all DVAs that would track variances to Income Tax expenses from 2027 to 2031 not captured in part a). Similar to above, please provide a breakdown of those Income Tax expenses by completing the following table:

Table 6: Income Tax Expense Details

$ million	2027	2028	2029	2030	2031

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense that are captured in DVAs					
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense where there is no DVA for variances					

Response

a) Existing and proposed deferral and variance accounts that relate to the capital related revenue requirement ("CRRR") of the 2027-2031 regulated hydroelectric in-service additions are the Capacity Refurbishment Variance Account ("CRVA"), an existing account, and the Global Hydroelectric Capital Variance Account ("GHCVA"), the Clean Electricity ITC Variance Account (OPG) and the Change of Laws Deferral Account (OPG), all three of which are newly proposed in this Application.

   i. The requested information is provided in Chart 1 below, on an estimated basis. OPG interprets "rate base as at the end of 2026" to be the sum of the year's (i) net property, plant and equipment closing balance for the regulated hydroelectric assets, and (ii) closing balance of working capital items; it was then reduced annually from 2027 to 2031 by ongoing depreciation and amortization on these assets.[1,2] Simplifying assumptions were used to bifurcate capital-related depreciation and amortization and capital cost allowance ("CCA") – between amounts related to the assets as at the end of 2026 versus in-service additions during the IR term – in the calculation of income taxes underpinning the CRRR.[3]

   ii. The requested information is provided in Chart 1 below, on an estimated basis. OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event. As discussed in Ex. H1-1-1, Section 7.2 and further in Ex. A1-3-2, Section 2.3.5, the proposed GHCVA is asymmetric in favour of ratepayers. As discussed in Ex. H1-

[1] Depreciation on regulated hydroelectric rate base as of 2026 from Ex. B2-4-1, Table 3, line 12, col. (b) and held constant throughout IR term.

[2] The amounts presented in Chart 1 in respect of the rate base as at the end of 2026 include impacts from forecast in-service additions for CRVA-eligible projects in 2025 and 2026. Such amounts will be subject to the CRVA in the bridge years and the IR term.

[3] CCA over the 2027-2031 period for the net property, plant and equipment as at the end of 2026 was determined by holding constant throughout the IR term the undepreciated capital cost ("UCC") pool at the end of 2026 subject to applicable CCA rates, with the only change to UCC year-over-year being the ongoing CCA on these assets.

1-1, Section 7.3, Clean Electricity Investment Tax Credits ("CEITC") are not reflected in the proposed revenue requirements; therefore, there is no CRRR associated with this account and any amounts so recorded during the IR term would be in favour of ratepayers. As discussed in Ex. H1-1-1, Section 7.1, the proposed Change of Laws Deferral Account (OPG) would be able to record recoverable amounts but is limited in scope to a change in legal requirements, making any entries during the IR term inherently unknowable and conditional on future events. For these reasons, Chart 1 provides the requested information with respect to deferral and variance account coverage for in-service additions eligible for the CRVA.

iii. The requested information is provided in Chart 1 below, on an estimated basis. These amounts represent the annual breakdown of the remaining CRRR underpinning the proposed 2027 revenue requirement and the 2028-2031 C-factor for the regulated hydroelectric facilities, after accounting for amounts provided in response to i) and ii) above.

Chart 1 - Capital Related Revenue Requirement Details

$ million	2027	2028	2029	2030	2031
For rate base as at the end of 2026					
Cost of Capital					
Short-Term Debt	7.3	6.4	6.2	5.5	4.4
Long-Term Debt	184.2	188.7	189.2	187.7	185.1
Common Equity	411.4	402.5	393.6	384.7	375.8
Total Cost of Capital	603.0	597.5	589.0	577.9	565.3
Depreciation Expense	188.3	188.3	188.3	188.3	188.3
Income Tax Expense	107.5	113.2	116.4	119.8	121.1
Any other Revenue Requirement Impact	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact relating to rate base as at the end of 2026	**898.8**	**899.1**	**893.7**	**886.0**	**874.7**
For 2027 to 2031 in-service additions where variances will be tracked in DVAs					
Cost of Capital					
Short-Term Debt	0.2	0.6	1.3	1.6	1.6
Long-Term Debt	6.2	16.4	39.9	53.7	65.2

$ million	2027	2028	2029	2030	2031
Common Equity	13.9	34.9	83.1	110.1	132.4
Total Cost of Capital	20.4	51.9	124.3	165.5	199.2
Depreciation Expense	4.9	12.5	29.8	39.9	48.4
Income Tax Expense[1]	(77.7)	(46.9)	(27.8)	(17.4)	(6.2)
Any other Revenue Requirement Impact	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact relating to 2027-2031 in-service additions that are captured in DVAs	**(52.4)**	**17.4**	**126.2**	**187.9**	**241.5**
For 2027 to 2031 in-service additions where there are no DVAs that would track variances					
Cost of Capital					
Short-Term Debt	0.1	0.3	0.6	0.7	0.7
Long-Term Debt	3.3	10.0	17.1	23.7	29.9
Common Equity	7.4	21.4	35.6	48.6	60.6
Total Cost of Capital	10.9	31.8	53.3	73.0	91.2
Depreciation Expense	22.1	27.6	31.6	35.4	35.0
Income Tax Expense	(2.5)	4.0	(1.0)	(0.8)	(4.2)
Any other Revenue Requirement Impact	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact relating to 2027-2031 in-service additions where there is no DVA for variances	**30.5**	**63.4**	**83.9**	**107.5**	**121.9**

[1] Income taxes associated with the CRRR eligible for the CRVA represent CCA related to 2027 to 2031 in-service additions only, without recalculation of the impact of "long-term project" rules described in Ex. F4-2-1, p.8, line 4-11.

b) Existing and proposed deferral and variance accounts that would track variances to regulated hydroelectric OM&A expenses for 2027-2031 are the CRVA and the Pension and OPEB Cost Variance Account (OPG), both existing accounts, and the Change of Laws Deferral Account (OPG), a newly proposed account in this Application. OPG declines to provide the requested information for 2028 to 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 requirement will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

The requested information is provided in Chart 2 below. OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event, such as the Change of Laws Deferral Account (OPG). Accordingly, Chart 2 provides the requested information with respect to deferral and variance account coverage for OM&A expenses eligible for the CRVA and the Pension and OPEB Cost Variance Account (OPG).

Chart 2 - OM&A Details

$ million	2027
2027 OM&A where variances will be tracked in DVAs	
Base OM&A	0.0
Project OM&A[1]	25.3
Outage OM&A	0.0
Allocation of Corporate Costs	0.0
Allocation of Centrally Held Costs[4]	25.1
Asset Service Fees	0.0
Any other OM&A Expense where variances are tracked in a DVA	0.0
Total Revenue Requirement Impact of 2027 OM&A Expense that are captured in DVAs	**50.4**
2027 OM&A where there are no DVAs that would track variances	
Base OM&A[2]	286.2
Project OM&A[3]	101.7
Outage OM&A	0.0
Allocation of Corporate Costs[2]	55.3
Allocation of Centrally Held Costs	(19.4)
Asset Service Fees[2]	25.2
Any other OM&A Expense where there is no DVA to track variances	0.0
Total Revenue Requirement Impact of 2027 OM&A where there is no DVA for variances	**449.0**

[1] Refer to Ex. F1-3-1, Table 1, Note 4.
[2] Refer to Ex. F1-1-1, Table 1, col. (l).
[3] Ex. F1-1-1, Table 1, line 2, col. (l) less $25.3M Project OM&A noted above.
[4] Pension and OPEB costs subject to deferral and variance account coverage are presented in this line for purposes of this response. Amount is per Ex. L-F4-AMPCO-115, Attachment 1, p.1, line 38 plus Ex. F4-4-1, Table 2, line 1, col. (l) less Ex. F4-3-2, Chart 13 (centrally held pension and OPEB costs therein).

c) Existing and proposed deferral and variance accounts that would track variances to gross revenue charges ("GRC") expense for 2027 to 2031 are the Hydroelectric Water Conditions Variance Account ("WCVA"), the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") and the Gross Revenue Charge Variance Account ("GRCVA"). All three are existing accounts.

As discussed in Ex. H1-1-1, Section 5.9, the Application proposes to expand the scope of the GRCVA to record, for all regulated hydroelectric facilities, GRC deductions that may be approved under Ontario Regulation 124/02 and to capture the revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to OPG's regulated hydroelectric stations. As discussed in Ex. H1-1-1, Section 5.1, the WCVA records the financial impact of differences in regulated hydroelectric production, including changes in GRC costs, arising from differences between actual and forecast water conditions. As discussed in Ex. H1-1-1, Section 5.4, the SBGVA records the financial impact of foregone production at the regulated hydroelectric facilities due to SBG conditions. Taken together, these accounts do not provide 100% deferral and variance account coverage for the GRC expenses, and the making of any entries into these accounts during the IR term is inherently unknowable and conditional on future events.

The requested information is provided in Chart 3 below. OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event. As discussed above, there is no such deferral or variance account coverage for the GRC expenses.

OPG declines to provide the requested information for 2028 to 2031 for the same reasons as discussed in part b) above.

Chart 3 - Fuel Expense Details

$ million	2027
2027 Fuel Expense where variances will be tracked in DVAs	
GRC Expense	0.0
Any other Fuel Expense where variances are tracked in a DVA	0.0
Total Revenue Requirement Impact from 2027 Fuel Expense that are captured in DVAs	**0.0**
2027 Fuel Expense where there are no DVAs that would track variances	

$ million	2027
GRC Expense[1]	352.2
Any other Fuel Expense where variances are tracked in a DVA	0.0
Total Revenue Requirement Impact from 2027 Fuel Expense where there is no DVA for variances	**352.2**

[1] Ex. F1-1-1, Table 1, line 7, col. (l).

d) The Income and Other Taxes Variance Account (OPG), an existing account, would track variances to regulated hydroelectric property tax expenses for 2027-2031. As discussed in Ex. H1-1-1, Section 5.5, this account would be able to record recoverable amounts with respect to property taxes but limited in scope to identified changes in legislative or regulatory changes and related triggers, making any entries in the IR term inherently unknowable and conditional on future events. OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event. For this reason, Chart 4 below provides the requested information without any deferral and variance account coverage.

OPG declines to provide the requested information for 2028 to 2031 for the same reasons as discussed in part b) above.

Chart 4 - Property Tax Details

$ million	2027
Total Revenue Requirement Impact from 2027 Property Tax Expense that are captured in DVAs	0.0
Total Revenue Requirement Impact from 2027 Property Tax Expense where there is no DVA for variances[1]	2.1

[1] Refer to Ex. F1-1-1, Table 1, line 10, col. (l).

e) The Ancillary Services Net Revenue Variance Account, an existing account, and the Change of Laws Deferral Account (OPG) would track variances to regulated hydroelectric Other Revenues (and associated costs) for 2027-2031. OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event, such as the Change in Laws Deferral Account (OPG). Accordingly, Chart 5 below provides the requested information with respect to deferral and variance account coverage for Other Revenues eligible for the Ancillary Services Net Revenue Variance Account.

OPG understands the second portion of the requested table as intending to refer to the 2027-2031 Other Revenue (rather than Property Tax Expense) where there are no deferral and variance accounts that would track variances.

OPG declines to provide the requested information for 2028 to 2031 for the same reasons as discussed in part b) above.

Chart 5 - Other Revenue Details

$ million	2027
2027 Other Revenue where variances will be tracked in DVAs	
Ancillary Services[1]	49.1
Segregated Mode of Operation	0.0
Water Transactions	0.0
Capacity Exports	0.0
Hydroelectric Incentive Mechanism (HIM) Revenue	0.0
Any additional Other Revenues where variances are tracked in a DVA	0.0
Total Revenue Requirement Impact from 2027 Other Revenues that are captured in DVAs	**49.1**
2027 Other Revenue where there are no DVAs that would track variances	
Ancillary Services	0.0
Segregated Mode of Operation[1]	1.9
Water Transactions[1]	1.3
Capacity Exports[1]	1.0
HIM Revenue[1,2]	17.8
Any additional Other Revenues where there are no DVAs to track variances	0.0
Total Revenue Requirement Impact from 2027 Other Revenues where there is no DVA for variances	**22.0**

[1] Refer to Ex. G1-1-1, Table 1, col. (l).
[2] The Hydroelectric Incentive Mechanism Variance Account is proposed to be terminated as of the effective date of the payment amounts order in this proceeding. Refer to Ex. H1-1-1, Section 5.3.

f) The Income and Other Taxes Variance Account (OPG), the SR&ED ITC Variance Account (OPG), an existing account for the nuclear facilities that is proposed to be extended to the regulated hydroelectric facilities in this Application, and the Pension and OPEB Cost Variance Account (OPG) would track variances to income tax expenses for the regulated hydroelectric facilities for 2027-2031, in addition to the deferral and variance accounts discussed in part a). OPG interprets the question to be with respect to deferral and variance accounts (i) that are able to record amounts that could be recovered from ratepayers, rather than asymmetrically in favour of ratepayers, and (ii) that do not have a partial scope or a scope that is conditional on a future triggering event, such as the Income and Other Taxes Variance Account (OPG). Accordingly, Chart 6 provides the requested information with respect to deferral and variance account coverage for income tax expenses eligible for the SR&ED ITC Variance Account (OPG) and the Pension and OPEB Cost Variance Account (OPG).

OPG declines to provide the requested information for 2028 to 2031 for the same reasons as discussed in part b) above.

Chart 6 - Income Tax Expense Details

$ million	2027
Total Revenue Requirement Impact from 2027 Income Tax Expense that are captured in DVAs	(2.7)
Total Revenue Requirement Impact from 2027 Income Tax Expense where there is no DVA for variances[1]	107.7

[1] Sum of 2027 income tax expense for rate base as at end of 2026 per part a) i) and income tax expense for 2027 in-service additions with no deferral and variance accounts tracking variances per part a) iii), less ($2.7M) above.

RATE BASE

1.0 PURPOSE

This evidence presents the rate base for OPG's regulated hydroelectric facilities and nuclear facilities, and Darlington New Nuclear Program ("DNNP") facilities, including the drivers of period-over-period differences. In addition, it provides a description of each of the components of rate base and the methodology by which these components are determined.

2.0 OVERVIEW

This evidence supports the request for approval of a rate base for OPG's nuclear facilities and the DNNP facilities for the IR term. Consistent with OPG's proposal to set hydroelectric payment amounts using a price-cap index custom IR framework, it also supports the request for approval of a rate base for OPG's regulated hydroelectric facilities for 2027. Rate base amounts for the regulated hydroelectric facilities amounts are also presented for 2028-2031, as they are used in the calculation of the custom capital factor for the annual adjustment mechanism proposed for the hydroelectric payment amounts in Ex. A1-3-2, Section 2.0. As discussed in Ex. A1-4-4, the Application reflects the expected transfer of certain OPG assets to DNNP LP under a lease arrangement with OPG by the end of 2025.

The forecast rate base for OPG's regulated hydroelectric facilities is $9,135.1M in 2027, $9,687.1M in 2028, $10,814.1M in 2029, $11,471.1M in 2030, and $12,007.4M in 2031 (Ex. B1-1-1, Table 1). The forecast rate base for OPG's regulated nuclear facilities is $15,794.7M in 2027, $16,328.3M in 2028, $16,265.0M in 2029, $16,867.5M in 2030, and $23,587.9M in 2031 (Ex. B1-1-1, Table 2). The forecast rate base for the DNNP facilities is $0.0M in 2027, $0.0M in 2028, $2.1M in 2029, $1,371.1M in 2030, and $6,530.0M in 2031 (Ex. B1-1-1, Table 3).

The evidence also presents the rate base for OPG's regulated hydroelectric facilities for 2013-2024 (actual) and 2025-2026 (budget) and the rate base for OPG's nuclear facilities for 2020-

2024 (actual) and 2025-2026 (budget). The rate base for the DNNP facilities for 2020-2026 is zero.

The components of rate base and the methodology used to calculate them are the same as those reflected in the rate base approved by the OEB in prior OPG proceedings.

The forecast of rate base for the bridge years and IR term is based on a forecast of net fixed/intangible in-service assets (including nuclear asset retirement costs, or "ARC", as applicable) and working capital associated with the regulated facilities. The rate base amounts for the historical period are based on actual balances for those years. As in prior OPG applications, working capital consists of cash working capital, fuel inventory (for nuclear facilities), and materials and supplies.

OPG's regulated hydroelectric rate base is increasing as the company enters a period of significant investment in its aging fleet to ensure continued safe and effective operations. This includes executing on a major turbine-generator refurbishment program to maintain reliability, redeveloping facilities where appropriate, and undertaking concrete and dam restoration and rehabilitation and other civil infrastructure projects. As shown in Ex. B1-1-1, Table 1, these necessary investments are driving forecasted increases in the hydroelectric net plant rate base of $875.8M over the 2022-2026 period and $2,872.3M over the IR term. The most significant in-service additions over the forecast period relate to the ongoing refurbishment program for OPG's largest generating stations (such as at the Sir Adam Beck generating complex) and the redevelopment of Kakabeka Falls Generating Station ("GS") and Matabitchuan GS that are at or near their end of life. Additional details on these programs can be found in Ex. D1-1-2.

OPG's nuclear rate base is generally tracking in line with the expectations established in EB-2020-0290, subject to an earlier return to service of units under the Darlington Refurbishment Program ("DRP") and the decision to refurbish Pickering Units 5-8. Over the 2027-2031 period, OPG's nuclear rate base is forecast to increase substantially, primarily due to the in-service additions for the Pickering Refurbishment Program ("PRP") in 2031. As shown in Ex. B3-1-1, Table 2, the PRP net plant rate base increases from $67.1M in 2026 to $6,139.3M by 2031 as the first Pickering unit, Unit 5, returns to service following refurbishment. Darlington's total net plant rate base, inclusive of the forecasted below-budget completion of the DRP, increases from $13,073.9M in 2026 to $14,712.6M in 2031, including forecast in-service additions for the Darlington Turbine Rotors Replacement project and several other large-scale, sustaining investments necessary to ensure reliable post-refurbishment performance and address emerging conditions, net of depreciation. Pickering's net plant rate base, excluding the PRP, increases from $204.3M in 2026 to $833.5M in 2031, reflecting the restarting of sustaining capital work which is necessary to support safe and reliable Pickering "second-life" operations. Pickering's net plant also reflects an extension of the accounting end-of-life date for Units 5-8 to 2070 to reflect their planned refurbishment, as discussed in Ex. F4-1-1, Section 3.5.2. Further details on the approach to the restarting of sustaining capital projects at Pickering can be found in Ex. D2-1-2, Section 3.0.

As discussed in Ex. D2-2-1, with the forecast rate base reflecting the return to service of the final Darlington unit, Unit 4, in April 2026, the Application proposes to clear all remaining DRP-related balances recorded in the Capacity Refurbishment Variance Account ("CRVA") as of December 31, 2024 and commits not to seek recovery, in any future application, of any unlikely final costs of the DRP that exceed the approved $12.8B budget. Subject to this commitment, OPG would record in the CRVA the revenue requirement of any differences between the amount and timing of the remaining actual expenditures and in-service amounts for the DRP and those forecasts reflected in the IR term revenue requirements approved in this proceeding. Further details on this proposal can be found in Ex. D2-2-1, Section 3.0.

As shown in Ex. B1-1-1, Table 3, the rate base for the DNNP facilities reflects net plant increasing to $1,360.5M in 2030 and then to $6,507.4M in 2031, as DNNP facilities' Unit 1 (including the Common Scope Facilities) enters commercial operation in October 2030. The rate base for the DNNP facilities prior to 2030 is minimal. Based on the anticipated lease arrangement between OPG and DNNP LP, the DNNP-related net plant inclusive of the transfer of the initial balances from OPG at the inception of the lease will represent leasehold improvements and be reported as a capital asset on DNNP LP's balance sheet. Section 14(2)2 of Ontario Regulation 53/05, ("O. Reg. 53/05") requires the OEB to accept as capital costs the cumulative prudently incurred costs: (i) forming part of the asset balances, in respect of any assets transferred from or licensed by OPG to DNNP LP in relation to the DNNP facilities, as reflected in the audited schedule of costs that is approved by OPG's Board of Directors; and, (ii) for any leasehold improvements made by DNNP LP in relation to the DNNP facilities. The DNNP lease arrangement, including the transfer of OPG's assets in respect of the DNNP facilities to DNNP LP, is discussed further in Ex. A1-4-4.

Ontario Regulation 53/05 establishes a mechanism that provides for recovery of interest amounts associated with the PRP and the DNNP prior to such assets being placed in service, effective January 1, 2026. As such, neither the PRP nor the DNNP facilities in-service additions, rate base values, or associated depreciation and amortization expense presented in the Application include capitalization of interest, beginning on January 1, 2026.[1] This concurrent cost recovery mechanism for both projects is detailed in Ex. I1-1-3.

The revenue requirement impact of any differences between the actual and forecasted net plant and associated depreciation and amortization expense during the IR term for the PRP, hydroelectric refurbishment and redevelopment projects, and other eligible projects, including as a result of the availability of Clean Electricity Investment Tax Credits ("CEITCs"), will be recorded in the CRVA. The revenue requirement impact of any differences between the actual and forecasted net plant and associated depreciation and amortization expense during the IR term for the DNNP, including as a result of the availability of CEITCs, will be recorded, subject to O. Reg. 53/05, in the Darlington New Nuclear Project Development Variance Account re Development ("DNNPVARD"). The CRVA is discussed in Ex. H1-1-1, Section 5.6 and the DNNPVARD in Ex. H1-1-1, Section 6.1.

Clean Electricity Investment Tax Credits are not assumed in OPG's 2025-2031 Business Plan or this Application, as discussed in Ex. F4-2-1, Section 3.6. To the extent they are available to OPG's regulated facilities or the DNNP facilities, the CE-ITCs will reduce the capital cost of the underlying projects and therefore in-service additions, rate base values and the associated

[1] Interest capitalized to the PRP and DNNP expenditures prior to January 1, 2026 is included in the applicable in-service additions and rate base values.

depreciation and amortization expense. To the extent the revenue requirement impact of these changes is not captured in an existing deferral or variance account, the Application proposes to record such impacts in a newly established Clean Electricity ITC Variance Account (OPG) for OPG's facilities and Clean Electricity ITC Variance Account (DNNP) for the DNNP facilities. These proposed accounts are discussed in Ex. H1-1-1, Sections 7.3 and 8.6, respectively.

OPG's nuclear rate base continues to include ARC for Darlington and Pickering, reflecting the approved 2022 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan and the subsequent update to the asset retirement obligation ("ARO") to reflect the extension of the accounting end-of-life date for Pickering Units 5-8 to 2070, as discussed in Ex. C2-1-1.

Although OPG will be responsible for the nuclear waste management and decommissioning obligations arising for the DNNP facilities, neither OPG nor DNNP LP's rate base includes any ARC in respect of the DNNP facilities. As further discussed in Section 3.1.3, OPG proposes that, pursuant to O. Reg. 53/05, the nuclear liabilities' costs for the DNNP facilities are to be recovered by OPG using the same methodology as the OEB has approved for the Bruce facilities, which, as described in Ex. C2-1-1, does not include ARC in rate base and instead recovers accretion expense less any earnings on the nuclear segregated funds, as recorded in OPG's consolidated financial statements.

The remainder of this evidence is organized as follows:

- Section 3.1 discusses the fixed/intangible asset component of rate base.
- Section 3.2 discusses the working capital component of rate base.
- Sections 4.1 to 4.3 compare OPG's regulated hydroelectric rate base, OPG's nuclear rate base and the DNNP facilities' rate base over time and, where applicable, to previous OEB-approved amounts, respectively.

3.0 COMPONENTS OF RATE BASE

3.1 Fixed and Intangible Assets

3.1.1 Overview

The forecast net plant rate base values for OPG's regulated hydroelectric facilities are projected at $9,115.6M in 2027, $9,667.6M in 2028, $10,794.5M in 2029, $11,451.6M in 2030, and $11,987.9M in 2031. The net plant for the 54 regulated hydroelectric facilities is presented separately for each of the Niagara Region, Eastern Region and Western Region in Ex. B2-1-1, Tables 1 and 2.[2]

The net plant rate base values for OPG's nuclear facilities, including ARC, are projected at $14,920.0M in 2027, $15,375.4M in 2028, $15,247.3M in 2029, $15,769.2M in 2030, and $22,435.9M in 2031. The net plant for OPG's nuclear facilities is presented separately for each of Darlington, Pickering, Operations and Project Support, and ARC in Ex. B3-1-1, Tables 1 and 2. The Darlington net plant is further separated between the values excluding the DRP, the DRP excluding the Heavy Water Storage and Drum Handling Facility ("D2O Storage") Project, and the D2O Storage Project.[3] The Pickering net plant is further separated as between values excluding the PRP and the PRP itself.

The net plant rate base values for the DNNP facilities are projected at $0.0M in each of 2027, 2028 and 2029, $1,360.5M in 2030, and $6,507.4M in 2031, as shown in Ex. B1-1-1, Table 3.

All fixed assets under construction and intangible assets under development are excluded from the rate base.

Virtually all of OPG's in-service fixed and intangible assets continue to be exclusively or near exclusively associated with specific generation facilities or groups of hydroelectric generating facilities. As in prior OPG proceedings, OPG's fixed and intangible assets used by multiple generating businesses such as certain information technology assets, or those within a

[2] The categorization of OPG's 54 regulated hydroelectric facilities across the three operating regional groups is described in Ex. A1-4-2.
[3] The OEB conducted a prudence review of the D2O Storage Project in EB-2020-0290. The rate base values in the Application reflect the results of that review.

generating business used by both regulated and unregulated operations such as Joint-use Renewable Generation assets, are not included in the rate base or the associated depreciation and amortization expense components of the revenue requirements. Instead, the corresponding generating businesses, now including the DNNP facilities, are charged an asset service fee for the use of these assets where applicable. Similarly, OPG's fixed and intangible assets to be used exclusively or near exclusively for the DNNP facilities, as well as nuclear fuel inventory owned by OPG for use at the DNNP facilities, are not included in OPG or DNNP LP's rate base or associated depreciation and amortization expense component of the revenue requirement. Instead, the DNNP facilities will be charged a corresponding asset service fee and nuclear fuel service fee once the facilities have been transferred to DNNP LP. Asset services fees are charged as an OM&A cost and are discussed further in Ex. F3-2-1. Nuclear fuel service fees for the DNNP facilities are detailed further in Ex. F2-5-1 and Ex. F3-2-1, Table 3.

3.1.2 Forecast Methodology and In-Service Additions

The Application is using the same rate base forecast methodology as in prior OPG proceedings. The forecast of net fixed/intangible in-service asset values for 2025-2031 is based on the property, plant, and equipment values (including intangible assets) as at December 31, 2024. In order to determine forecasts for 2025-2031, these values are rolled forward based on a forecast of in-service additions (including adjustments to ARC, if any), retirements/transfers/adjustments, and depreciation/amortization on these assets.

Exhibit D1-1-2, Table 4 summarizes the forecast in-service additions for OPG's regulated hydroelectric facilities. Exhibit D2-1-3, Tables 4a and 4b, Ex. D2-2-3, Tables 5a and 5b and Ex. D2-3-8, Table 5 summarize the forecast in-service additions for the Nuclear Operations, the DRP and the PRP, respectively. Exhibit D3-1-2, Table 4 summarizes the forecast in-service additions for the Support Services, with Tables 5a and 5b separately presenting such forecast in-service additions that are included in OPG's regulated hydroelectric rate base and OPG's nuclear rate base, and those that impact the IR term asset service fees and therefore are not included in the rate base. Exhibit D2-4-8, Table 6 summarizes the forecast in-service additions for the DNNP that form part of the rate base for the DNNP facilities.

A summary of the forecast in-service additions from the above capital projects exhibits (Ex. D) and those presented in the rate base exhibits (Ex. B) for 2025-2031 is provided below in Chart 1.

Chart 1
Summary of Forecast In-Service Capital Additions* ($M)

Line No.	Prescribed Facility	Reference	2025	2026	2027	2028	2029	2030	2031
	Regulated Hydroelectric								
1	Regulated Hydroelectric Capital Projects Entering Regulated Hydroelectric Rate Base	Ex. D1-1-2, Table 4	419	532	842	1,105	1,116	938	627
2	Support Services Capital Projects Entering Regulated Hydroelectric Rate Base	Ex. D3-1-2, Table 4	2	0	2	2	2	2	2
3	**Total Regulated Hydroelectric In-Service Additions**		**421**	**533**	**843**	**1,106**	**1,117**	**940**	**629**
	OPG Nuclear Facilities								
4	Nuclear Operations Capital Projects	Ex. D2-1-3, Table 4a and Table 4b	422	581	848	800	1,005	1,408	959
5	Pickering Refurbishment Project	Ex. D2-3-8, Table 5	-	159	21	-	-	-	9,688
6	Darlington Refurbishment Project	Ex. D2-2-3, Table 5a and Table 5b	39	2,299	-	-	-	-	-
7	Support Services Capital Projects Entering OPG Nuclear Rate Base	Ex. D3-1-2, Table 5a and Table 5b	32	37	134	62	67	71	40
8	**Total Nuclear In-Service Additions, Excluding ARC**		**493**	**3,076**	**1,002**	**862**	**1,072**	**1,479**	**10,686**
	DNNP Facilities								
9	**Total DNNP Facilities In-Service Additions**	Ex. D2-4-8, Table 6	**-**	**-**	**-**	**-**	**-**	**6,585**	**-**

*Amounts may not add due to rounding

The depreciation and amortization forecasts for 2025-2031 are determined by applying the estimated service lives and depreciation and amortization policy to the opening in-service fixed/intangible asset values and planned additions during the year. These depreciation/amortization forecasts are presented in Ex. F4-1-1, Tables 1 and 2. The depreciation/amortization policy and an independent review and assessment of the asset service life estimates are presented in Ex. F4-1-1.

The net fixed/intangible asset portion of rate base is determined using a mid-year average methodology. For large in-service additions or adjustments, where the in-service addition amount or the amount of an adjustment exceeds $50M, the month in which the addition or adjustment is reflected continues to be used, instead of a mid-year average, to improve accuracy. There are 13 regulated hydroelectric in-service addition amounts forecasted during the bridge years and IR term that are greater than $50M, the details of which are found in Ex.

B2-3-1, Table 3a, Note 1. There are 18 in-service addition amounts for OPG's nuclear facilities and one in-service addition amount for the DNNP facilities forecasted during the bridge years and IR term that are greater than $50M, the details of which are found in Ex. B3-3-1, Tables 1a and 2a, Note 1.

For example, OPG's nuclear rate base reflects a forecasted in-service amount of $9,688.0M on May 15, 2031 related to the return to service from refurbishment of Pickering Unit 5. Accordingly, the nuclear rate base forecast for 2031 reflects a weighting of 7.5/12th for this in-service amount.

Supporting continuity schedules for the gross plant, gross in-service fixed/intangible assets and related accumulated depreciation and amortization for the regulated hydroelectric facilities are provided in Ex. B2-3-1, Tables 1, 2, and 3 and Ex. B2-4-1, Tables 1, 2 and 3. For OPG's nuclear facilities and the DNNP facilities, the same supporting continuity schedules are provided in Ex. B3-3-1, Tables 1 and 2 and Ex. B3-4-1, Tables 1 and 2.

3.1.3 Asset Retirement Costs

Asset retirement costs for OPG's prescribed facilities for 2020-2031 are discussed in Ex. C2-1-1, with detailed continuity schedules of ARC and ARO presented in Ex. C2-1-1, Table 2. This includes several increases in ARC, being $51.1M recorded at the end of 2020 related to the change in the ARO reflecting revised accounting end-of-life assumptions for Pickering effective December 31, 2020, $272.6M recorded at the end of 2021 related to the change in ARO reflecting the approved 2022 ONFA Reference Plan, and $474.1M at the end of 2023 related to the change in the ARO reflecting the extension of accounting end-of-life date for Pickering Units 5-8 to December 31, 2070 based on the expectation of their refurbishment.

Neither OPG nor DNNP LP's proposed rate base includes any ARC in respect of the DNNP facilities. As discussed in Ex. C2-1-1, Section 8.0, O. Reg. 53/05 requires the OEB to ensure that OPG recovers all the costs it incurs in relation to its nuclear liabilities with respect to the DNNP facilities as they are reflected in OPG's audited financial statements approved by OPG's Board of Directors. OPG proposes that the nuclear liabilities' costs for the DNNP facilities are to be recovered by OPG using the same methodology as the OEB has approved for the Bruce facilities, which, as described in Ex. C2-1-1, does not include ARC in the rate base and instead includes accretion expense less any segregated fund earnings, as recorded in OPG's consolidated financial statements.[4]

3.2 Working Capital

3.2.1 Overview

As in prior OPG applications, the working capital included in rate base consists of cash working capital, fuel inventory and materials and supplies, as applicable. The fuel inventory and materials and supplies values for rate base continue to be determined using a mid-year average of opening and closing balances during the period. Cash working capital continues to be determined using a lead/lag analysis.

Total working capital for the regulated hydroelectric facilities is forecasted to be $19.5M each year during the 2027-2031 period (Ex. B2-5-1, Table 2). Total working capital for OPG's nuclear facilities is forecasted to be $874.7M in 2027, $952.9M in 2028, $1,017.7M in 2029, $1,098.4M in 2030, and $1,152.1M in 2031 (Ex. B3-5-1, Table 2). Total working capital for the DNNP facilities is forecasted to be zero in 2027 and 2028, $2.1M in 2029, $10.5M in 2030, and $22.6M in 2031 (Ex. B3-5-1, Table 3).

[4] As discussed in Ex. C2-1-1, Section 8.0, OPG has not yet developed comprehensive cost estimates for its future nuclear liabilities for the DNNP facilities, and none have been recorded in OPG's consolidated financial statements. Accordingly, there are no corresponding amounts included in OPG's proposed nuclear revenue requirements for the IR term. Once incurred, such costs during the IR term are proposed to be recorded in a newly established DNNP Nuclear Liability Deferral Account for future recovery in accordance with O. Reg. 53/05, as discussed in Ex. H1-1-1, Section 7.0.

3.2.2 Cash Working Capital

The methodology for calculating OPG's cash working capital is the same as in prior OPG proceedings. Cash working capital is the average amount of capital needed to bridge the gap between the time expenditures are made to produce output and the time payment is received for that output. Cash working capital is calculated using net lag days, which is the difference between the time that revenue is received and the time that expenses are paid. The net lag is applied to each of the expenses in determining the cash working capital amount.

The net lag days used in OPG's cash working capital calculations were determined by a lead/lag study conducted by Navigant Consulting Inc. in 2019, the results of which were reflected in the EB-2020-0290 nuclear payment amounts. As discussed, and shown in Ex. B1-1-2, OPG has calculated its cash working capital amounts for the 2025-2031 period by applying the net lag days from that study to the relevant expenses for those years for OPG's regulated hydroelectric facilities and OPG's nuclear facilities. Given the modest size of cash working capital relative to the total rate base, the Application continues to use the cash working capital amounts of the most recent historical year (i.e., 2024) as the basis for the amounts in the bridge years and the IR term.

Cash working capital for the DNNP facilities is considered in the rate base beginning as of the forecasted in-service date of DNNP facilities' Unit 1 in October 2030. Recognizing the relatively short period during the IR term that this cash working capital will apply and its anticipated modest size based on OPG's nuclear facilities' experience, the cash working capital for the DNNP facilities is estimated based on a proration of the 2031 operating expenses for the DNNP facilities relative to OPG's nuclear facilities.[5] As appropriate, this methodology will be re-evaluated in the next rebasing application for the DNNP facilities.

3.2.3 Fuel Inventory

The hydroelectric generating stations do not require any fuel inventory. OPG's nuclear facilities maintain a Canadian Deuterium Uranium ("CANDU") nuclear fuel inventory as well as an

[5] Refer to Ex. B3-5-1, Table 3, Note 1 for further details.

inventory of fuel oil for standby generators. The cost of the inventory of fuel oil remains minimal compared to that of nuclear fuel for OPG's nuclear facilities.

A nuclear fuel inventory will also be required for the DNNP facilities, which will be Low-Enriched Uranium nuclear fuel. Low-Enriched Uranium fuel is a different type of fuel than CANDU fuel and requires a certain separate supply chain for processing and fabrication. The cost of the inventory of fuel oil is minimal compared to that of nuclear fuel for the DNNP facilities.

Chart 2 below provides details of the year-end nuclear fuel inventory for OPG's nuclear facilities for 2020-2031 and the DNNP facilities for 2026-2031.

Chart 2

Summary of Year End Inventory – OPG Nuclear Facilities and DNNP Facilities

Line No.	Prescribed Facility Category	Units	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
	OPG Nuclear Facilities		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Uranium Concentrate	K$	36,403	38,628	35,172	42,837	36,559	53,944	77,937	[redacted]				
2		MgU	316	360	288	306	242	257	338	332	227	227	227	258
3		$/KgU	115.2	107.4	122.0	140.1	150.9	210.0	230.9	[redacted]				
4	Uranium Dioxide[1]	K$	14,590	16,758	20,426	21,202	21,558	17,229	12,409					
5		MgU	[redacted]											
6		$/KgU												
7	Finished Bundles	K$	133,888	140,811	130,715	173,644	169,762	186,345	176,314	[redacted]				
8		MgU	568	620	557	685	623	569	485					
9		$/KgU	235.6	227.3	234.5	253.3	272.4	327.5	363.3	398.4	425.4	458.7	484.9	505.4
10	Fuel Oil	M$	5.4	5.2	5.2	5.2	5.2	5.5	5.5	5.5	5.5	5.5	5.5	5.5
11	**Total**	**M$**	**190.3**	**201.4**	**191.5**	**242.9**	**233.1**	**263.0**	**272.2**	**365.1**	**416.2**	**496.6**	**535.0**	**577.6**
	DNNP Facilities[2]													
12	Uranium Concentrate	K$	0	0	0	0	0	0	0	0	0	7,388	0	0
13		MgU	0	0	0	0	0	0	0	0	0	[redacted]	0	0
14		$/KgU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
15	Uranium Hexafluoride	K$	0	0	0	0	0	0	45,379	68,281	15,690	42,430	19,988	64,805
16		MgU	0	0	0	0	0	0	[redacted]					
17		$/KgU	0.0	0.0	0.0	0.0	0.0	0.0						
18	Enriched Uranium Product	K$	0	0	0	0	0	0	0	36,139	107,498	36,139	36,139	36,139
19	Fuel Oil	M$	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.1	0.1	0.1
20	**Total**	**M$**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**45.4**	**104.7**	**123.3**	**86.0**	**56.2**	**101.0**

[1] Includes reusable inventory resulting from the fuel bundle manfacturing process
[2] Applicable to BWRX-300 SMR Unit 1.

<u>OPG Nuclear Facilities Fuel Inventory</u>

As described in Ex. F2-5-1, the supply chain for CANDU nuclear fuel for OPG's facilities continues to consist of the purchase of uranium concentrate, the purchase of services to convert the uranium concentrate into uranium dioxide, and the purchase of services to manufacture fuel bundles that contain the uranium dioxide. OPG maintains inventories at each stage and maintains ownership of the work-in-process throughout this supply chain. The fuel inventory costs represent the accumulation of costs incurred by OPG during the supply chain process. The inventory continues to be valued using the weighted average costing method.

For the CANDU nuclear fuel inventory, amounts for 2025-2031 are forecasted based on the closing nuclear fuel inventory quantities and values as of December 31, 2024, and expected purchases and usage during the forecast period. The purchases reflect OPG's current target levels for the inventory, including the impact of temporarily reduced fuel requirements due to the planned refurbishment outages for Pickering Units 5-8, followed by the requirement for a first load of fuel for each of these units prior to returning to service beginning in 2031, as further discussed in Ex. F2-5-1. Pricing assumptions for the nuclear fuel supply chain components over the forecast period are also discussed in Ex. F2-5-1.

DNNP Facilities Unit 1 Fuel Inventory

The supply chain for the Low-Enriched Uranium for the BWRX-300 SMRs consists of the purchase of uranium concentrate, the purchase of services to convert the uranium concentrate to natural uranium hexafluoride, the purchase of services to convert the natural uranium hexafluoride to enriched uranium product ("EUP"), the purchase of services to convert the EUP to enriched uranium dioxide, and the purchase of services to manufacture fuel assemblies that contain the enriched uranium dioxide.[6] The procurement of these fuel components reflect OPG's current contracting strategies, target inventory levels, and planning assumptions, as described further in Ex. F2-5-1.

The fuel inventory costs represent the accumulation of costs incurred by OPG during the applicable stages of the supply chain process. The inventory is valued using the weighted average costing method. Unlike the CANDU fuel bundles utilized in OPG's nuclear facilities, the BWRX-300 fuel assemblies are uniquely designed and delivered for each outage cycle, are not interchangeable, and therefore will not be held in inventory. All inventory amounts included in the Application are applicable to DNNP Unit 1.

[6] For the initial material contracts for DNNP facilities Unit 1, OPG elected to purchase the natural uranium hexafluoride directly, which includes the costs of the contained uranium concentrate and that of the natural uranium hexafluoride conversion services.

Under the DNNP LP partnership arrangements, OPG is expected to procure, manage, and maintain ownership of the nuclear fuel for the DNNP facilities, charging DNNP LP a service fee for the costs of the nuclear fuel inventory and its consumption (Ex. A1-4-4). The forecast nuclear fuel service fees for 2027-2031 are provided in Ex. F2-1-1, Table 1b, and calculated in Ex. F3-2-1, Table 3.

3.2.4 Materials and Supplies

Materials and supplies consist of consumable supplies and spare parts. All of OPG's regulated facilities maintain materials and supplies, with the regulated hydroelectric facilities typically requiring a minimal amount (less than $1M) of materials and supplies on hand. OPG's nuclear facilities are required to maintain substantial amounts of materials and supplies. The DNNP facilities will also be required to maintain certain materials and supplies, largely specific to the BWRX-300 SMRs. The rate base materials and supplies value for OPG's nuclear facilities and the DNNP facilities is net of a provision for accumulated obsolescence discussed below. The inventory management system uses an average costing basis, whereby the value of the materials and supplies inventory is based on the average unit price of each item times the quantity on hand.

In accordance with US GAAP, materials and supplies continue to be valued at the lower of average cost and market value. The determination of the market value of materials and supplies takes into account various factors including technological obsolescence, the remaining life of the related facilities in which the materials and supplies are expected to be used, and adjustments required as a result of performing physical inventory counts. Charges incurred as a result of valuing OPG's nuclear materials and supplies at the lower of cost and market value are reflected in the inventory adjustments (charged to nuclear base OM&A costs) that reduce the nuclear materials and supplies rate base amount.

The forecasted nuclear materials and supplies values for OPG's facilities are based on the closing materials and supplies balance as of December 31, 2024 and expected utilization, purchases, and charges related to valuation at the lesser of cost and market value during the forecast period, based on the 2025-2031 Business Plan. This methodology is unchanged from prior applications. Targeted materials and supplies inventory gross growth rates for OPG's nuclear facilities are shown in Chart 3 below.

Chart 3

Targeted OPG Materials and Supplies

	2026	2027	2028	2029	2030	2031
PNGS	0.18%	-2.63%	-0.98%	0.49%	4.00%	-2.39%
DNGS	2.18%	-0.21%	-0.21%	-0.22%	-0.22%	2.00%
OPG Nuclear Facilities	**2.36%**	**-2.84%**	**-1.19%**	**0.27%**	**3.78%**	**-0.39%**

For Pickering, modest or negative gross inventory growth rates in the initial forecast years reflect Units 5-8 entering the refurbishment outage in late 2026 and progressing through the refurbishment, before the inventory levels increase ahead of the first unit returning to service in 2031. This trend aims to balance between optimizing inventory in view of the pause in online station operations and ensuring sufficient supply to support refurbishment needs. Darlington's gross inventory is forecast to remain relatively stable over the IR term, with the upcoming completion of the DRP reducing operational spares/inventory transfers. OPG continues to monitor and manage internal demand, work planning and ordering accuracy in respect of the materials and supplies inventory with a view to optimize and mitigate the associated costs.

Materials and supplies for the DNNP facilities are expected to be an asset of DNNP LP and are reflected in the DNNP facilities' rate base. Such forecasted materials and supplies values are for Unit 1 and reflect expected purchases during the forecast period. Annual inventory targets reflect a baseline level of materials and supplies expected to be necessary to support Unit 1 commercial operation beginning in 2030, including during the preceding commissioning activities. With less than 15 months of expected Unit 1 commercial operation during the IR term, a minimal provision for obsolescence has been applied against these forecasted materials and supplies values.

4.0 COMPARISON OF RATE BASE

4.1 Comparison of Regulated Hydroelectric Rate Base

A comparison of rate base amounts for the regulated hydroelectric facilities, consisting almost exclusively of net plant, is presented in Ex. B2-2-1, Table 1. Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, this evidence provides nine years of historical data for OPG's regulated hydroelectric business, for the period 2016-2024.[7]

Over the 2016-2026 period, the regulated hydroelectric rate base increases by an average of approximately 1.5% annually, from $7,423.6M to $8,610.5M. This represents a stable rate base during the period up to 2021, reflecting the impact from work programs that were largely aimed at sustaining the fleet's ongoing performance, followed by an increase of $875.8M between 2022-2026, driven largely by in-service additions for major refurbishment, redevelopment, and rehabilitation works necessary to continue safe and effective performance given the advanced age of the regulated hydroelectric fleet. As further discussed in Ex. D1-1-1 and Ex. D1-1-2, the larger projects placed or forecasted to be placed in service during the 2022-2026 period include the Calabogie GS Redevelopment, Coniston GS / Stinson GS Redevelopment, the Sir Adam Beck G1/G2 Replacement, and the Frederick House Lake Dam Rehabilitation, which collectively account for approximately one-half of the rate base increase.

Over the IR term, the regulated hydroelectric rate base increases from $9,135.1M to $12,007.4M, reflecting in-service additions from further investment levels required across the fleet. As discussed in Ex. D1-1-1 and Ex. D1-1-2, the larger projects forecasted to be placed in service include the Kakabeka Falls GS Redevelopment, the Matabitchuan GS Redevelopment, the refurbishment of seven units at the Sir Adam Beck Generating Stations (G4, G6/G8, G17/G18, and G19/G20), the Sir Adam Beck 1 GS Canal Isolation Preparedness Phase 1, the Abitibi Canyon GS Concrete and Sluiceway Rehabilitation, and the Aguasabon Dam Rehabilitation: Hayes Lake Main Dam, which collectively account for approximately two-thirds of the rate base increase.

[7] In addition, OPG provides historical rate base amounts for OPG's regulated hydroelectric business on a combined basis only from 2013-2015 within Ex. B1-1-1, Table 1.

Additional details regarding in-service additions for the regulated hydroelectric facilities and Support Services projects impacting the hydroelectric rate base amounts are provided in Ex. D1-1-2 and D3-1-2, respectively.

4.2 Comparison of OPG's Nuclear Rate Base

A comparison of rate base amounts for OPG's nuclear facilities for the 2020-2031 period is presented at Ex. B3-2-1, Table 1. The EB-2020-0290 rate base amounts shown in the comparison reflect the settlement adjustments and other approved adjustments by the OEB in that proceeding.

Over the 2020-2026 period, the overall increase in rate base from $6,838.2M to $14,856.2M is driven largely by the increase in the DRP net plant from $3,691.8M to $9,938.7M from in-service additions related to the return to service of refurbished Darlington Units 2, 3, and 1 in 2020, 2023 and 2024, respectively, and the forecasted return to service of Unit 4 in April 2026. The non-DRP Darlington net plant increases from $1,507.7M in 2020 to $3,135.2M in 2026, inclusive of the emergent Darlington Steam Generator Moisture Separator Replacement projects and otherwise in line with the OEB-approved levels in EB-2020-0290. The overall Pickering net plant decreases from $482.4M in 2020 to $271.4M in 2026, due to depreciation. The ARC rate base increases from $406.3M in 2020 to $505.0M in 2026, reflecting the impact of the adjustments recorded on December 31, 2020, December 31, 2021, and December 31, 2023, as discussed in Section 3.1.3, net of depreciation.

Over the IR term, OPG's nuclear rate base increases from $15,794.7M to $23,587.9M, driven primarily by the increase in the PRP net plant from $166.4M in 2027 to $6,139.3M in 2031 as a result of the in-service additions for Unit 5 and the Deep-Water Intake. The overall Pickering NGS net plant, which increases from $428.9M in 2027 to $6,972.8M in 2031, also reflects the resumption of sustaining capital work in support of post-refurbishment operation of Units 5-8. The overall Darlington net plant increases from $13,728.1M in 2027 to $14,712.6M in 2031, mainly driven by IR term in-service additions for the Darlington Turbine Rotors Replacement project, the remainder of the Darlington Steam Generator Moisture Separators Replacement projects and several other major equipment replacements and rehabilitations at Darlington.

The ARC rate base decreases over the IR term, primarily due to depreciation, from $493.7M in 2027 to $448.3M in 2031.

Excluding ARC, OPG's nuclear rate base is forecasted to be $1,453.9M higher than the OEB-approved amount by 2026. This primarily reflects a higher DRP-related net plant by $766.5M driven by the earlier expected return to service of refurbished Darlington Unit 4 in April 2026, higher Pickering net plant, fuel inventory and materials supplies rate base values due to continued operation of Pickering Units 5-8, which for rate base purposes was not anticipated beyond 2024 in EB-2020-0290, and in-service additions for the Darlington Steam Generator Primary Moisture Separators Replacement projects. The ARC rate base is forecasted to be $410.5M higher than the OEB-approved amount by 2026 due to the extension of the accounting end-of-life assumption for Pickering Units 5-8 to December 31, 2070 and the impact of the ARC adjustments recorded on December 31, 2020, December 31, 2021, and December 31, 2023, as discussed in Section 3.1.3.

Additional details regarding in-service additions for Nuclear Operations are provided in Ex. D2-1-3. Details regarding in-service additions for the DRP and PRP are provided in Ex. D2-2-3 and Ex. D2-3-8, respectively. Details regarding Support Services projects impacting OPG's nuclear rate base amounts are provided in Ex. D3-1-2.

4.3 Comparison of DNNP Facilities Rate Base

Rate base amounts for the DNNP facilities for the 2025-2031 period are presented at Ex. B1-1-1, Table 3. The rate base increases during the IR term as the DNNP facilities' Unit 1 is forecast to enter commercial operation in October 2030. With the first full year weighting of the net plant component, the rate base reaches $6,530.0M in 2031. Additional details regarding the in-service additions for DNNP are provided in Ex. D2-4-8**.** With approvals being sought of rate base amounts for the DNNP for the first time in this proceeding, there are no prior OEB-approved amounts for comparison.

Exhibit L-C1-SEC-035, Attachment 1

OPG Modelled Financial Metrics - With and Without CCR

This Attachment was filed as confidential information in its entirety.

Board Staff Interrogatory #029

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / pp. 1, 5-7

Preamble:

OPG stated that it has made updates to the methodology used to determine the cost of planned long-term debt issues in this application, compared to previous proceedings.

OPG noted that previously IHS Markit's Global Insight Economics (Global Insight) was used as a third-party market source for forecast Government of Canada (GoC) bond rates.

OPG also noted that there is an increased volume of planned debt issues, as well as observed notable divergence in forecast data between Global Insight and other economist views. Over the 2025-2031 period, OPG forecasts issuing approximately $10 billion in long-term debt that is wholly or partially attributed to its regulated operations and which will support the planned capital investments. OPG stated that this does not include the forecast long-term debt issues attributed to OPG's anticipated cash contributions to DNNP LP, beginning in 2026.

OPG stated that the forecast in this proceeding has been determined using an equally weighted combination of 10-year and 30-year durations.

OPG stated that Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy.

Question(s):

a) Please explain why there is an "Increased volume of planned debt issues", other than supporting planned capital investments.

b) Please explain how OPG concluded it was appropriate to use "an equally weighted combination of 10-year and 30-year durations" to determine its forecast, rather than other proportions.

c) Please explain why OPG is stating in the current application that there was an "observed notable divergence in forecast data between Global Insight and other economist views" and not in prior proceedings.

d) Please explain whether OPG attempted to use different methodologies to develop long-term debt costs and short-term debt costs, other than using Bloomberg forecasts, given OPG's statement that "Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy."

Response

a) The increased volume of planned debt issues referenced is due to OPG's increased funding requirements, driven by planned capital investments in the regulated assets.

b) OPG determined that it is appropriate to use an equally weighted combination of 10-year and 30-year durations to determine the forecast cost of long-term debt because, as stated at Ex. C2-1-1, p. 5, lines 3-5, such assumption is "consistent with the transaction OPG undertakes through its Medium-Term Notes program." For example, since EB-2020-0290, OPG has only issued 10- and 30-year tenor bonds, with such corporate-wide and Green Bond issues shown at Ex. C1-1-2, Table 7 having a weighted average original tenor of 18 years. As noted at Ex. C1-1-2, p. 5, lines 5-7, this approach better matches the longer-term nature of the assets and reduces near-term refinancing risk, while resulting in more competitive pricing dynamics.

c) While OPG did not conduct a comprehensive historical review of IHS Markit's Global Insight Economics ("Global Insight") forecast going back to prior payment amounts proceedings, the referenced statement reflects the observations that OPG made in the course of 2024 and 2025 that, when compared to the Bloomberg Bond Yield Median Forecast ("BYFC") and the forward rates, Global Insight's 10-year Government of Canada ("GoC") bond yield exhibited significant month-to-month variability when considering 1) forecasted rates within the same forecast, and 2) from one forecast to the following forecast produced in the next month. Further, OPG also noticed that historical rates in Global Insight's forecast had started to change, when this historical data should be the actual GoC rate. These three issues are discussed further below.

1. **Variability within the same forecast:** OPG observed significant decreases in forecasted rates on a month-to-month basis within the same Global Insight forecast. This was prevalent for many of the forecasts generated by Global

Insight for 2024 and 2025. As an example, for the forecast produced in February 2025, Global Insight's 10-year GoC forecast from January to February 2025 decreased by 0.44%. Such a significant change was not observed in either the BYFC (representing approximately a dozen economist forecasts, as discussed below), or in the Bloomberg forward rates being predicted at that time. Notably, OPG observed such month-to-month decreases of greater than 0.35% in seven monthly forecasts produced by Global Insight for 2025. Chart 1 ranks the greatest month-to-month changes within the same forecast as published for 2025 by Global Insight.

By comparison, the greatest change OPG observed month-to-month in the Bloomberg forward rates produced monthly from January 2025 to February 2026 was 0.02%. Similarly, the greatest change OPG observed month-to-month in the BYFC produced monthly from January 2025 to February 2026 were two instances of 0.25%.[1]

Chart 1 - Global Insight 2025 Forecasts with Month-to-Month Variability within Same Forecast, where Change in Yield is >0.35%

Month Forecast was Published	Forecast 10-Year GoC in Starting Month		Forecast 10-Year GoC in Following Month		Change in Forecasted GoC
June 2025	May 2025	3.48%	June 2025	2.36%	-1.12%
March 2025	February 2025	3.15%	March 2025	2.11%	-1.04%
April 2025	June 2025	3.60%	July 2025	2.92%	-0.68%
March 2025	March 2025	2.11%	April 2025	2.73%	0.62%
August 2025	September 2025	3.45%	October 2025	2.90%	-0.55%
June 2025	June 2025	2.36%	July 2025	2.91%	0.55%
September 2025	August 2025	3.82%	September 2025	3.33%	-0.49%
May 2025	May 2025	2.89%	June 2025	2.41%	-0.48%
May 2025	April 2025	3.36%	May 2025	2.89%	-0.47%
February 2025	January 2025	3.32%	February 2025	2.88%	-0.44%
February 2025	February 2025	2.88%	March 2025	2.45%	-0.43%
September 2025	September 2025	3.33%	October 2025	2.98%	-0.35%

[1] Although the BYFC is published monthly, it forecasts quarterly 10-year GoC rates. Accordingly, a somewhat larger change quarter-to-quarter in their monthly forecast is to be expected compared to the forecasted monthly Bloomberg forward rates.

2. **Variability from one forecast to another:** Global Insight's forecasts are published monthly, and there was often significant variability *between* each of the monthly forecasts that were published, beyond what was observed in either the BYFC or Bloomberg forward rates. For example, in the forecast published in July 2025, Global Insight forecasted a 10-year GoC rate of 2.86% for August 2025. In the subsequent forecast published in August 2025, Global Insight had revised their August 2025 10-year GoC forecast to 3.70%, an increase of 0.84%. Meanwhile, both sources from Bloomberg showed more muted revisions for the forecasted August 2025 10-year GoC yield of approximately 0.20%. Notably, OPG observed over 100 instances spanning eight monthly forecasts produced by Global Insight during 2025 where the change in the forecast 10-year GoC for a given month was 0.35% greater than the subsequent published Global Insight forecast for that same month. Chart 2 ranks such greatest changes in the forecast 10-Year GoC rate by Global Insight from one forecast to the next.

   By comparison, for both the BYFC and Bloomberg forward rates, OPG observed no instances where the change in the forecast GoC rate for a given month was greater than 0.35% for that same month in the subsequent forecast.

Chart 2 - Global Insight 2025 Forecasts with Variability for Same Month between Successive Forecasts, where Change in Yield is >0.35%

Month Original Forecast Published	Month Subsequent Forecast Published	Forecast Month(s) in Question	Original Forecasted Yield	Subsequent Forecasted Yield	Change in Yield Between Forecasts
June 2025	July 2025	June 2025	2.36%	3.60%	1.24%
March 2025	April 2025	March 2025	2.11%	3.32%	1.21%
July 2025	August 2025	July 2025	2.92%	3.77%	0.85%
July 2025	August 2025	August 2025	2.86%	3.70%	0.84%
July 2025	August 2025	September 2025	2.82%	3.45%	0.63%
May 2025	June 2025	May 2025	2.89%	3.48%	0.59%
September 2025	October 2025	October 2025 - May 2027	2.65% - 2.98%	3.20% - 3.53%	20 instances >0.40%, including 9 >0.50%

November 2025	December 2025	February 2026 - October 2028	2.83% - 3.04%	3.27% - 3.48%	33 instances of 0.44%
April 2025	May 2025	April 2025	2.98%	3.36%	0.38%
March 2025	April 2025	July 2027 - February 2028	2.56% - 2.59%	2.94% - 3.00%	8 instances >0.37%
October 2025	November 2025	August 2025 - September 2028	3.19% - 3.82%	2.83% - 3.42%	36 instances >0.35%

3. **Changes in historical actual data within the forecast that should have remained unchanged:** Global Insight publishes monthly forecasts in spreadsheet format that includes both historical actual 10-year GoC yields and that month's forecast of future 10-year GoC yields. The historical actual 10-year GoC yields, however, changed in Global Insight's November 2025 publication when, as historical actual yield data, it should have remained static. Specifically, OPG observed that the historical GoC yields for the entire period inclusive from January 2000 to September 2025 had changed in the forecast spreadsheet published by Global Insight in November 2025 when compared to such spreadsheet produced in October 2025. For example, the October 2025 spreadsheet had a historical March 2025 GoC yield of 3.32% compared to the November 2025 spreadsheet reporting such yield at 3.01%, a decrease of 0.31%.

In Attachment 1, OPG has reproduced, for comparison, the full history of Global Insight's 10-year GoC forecasts, the 10-year BYFC, and the Bloomberg 10-year forward curves, compiled from January 2024 to March 2026. OPG observes that the Global Insight forecasts diverged significantly from both the BYFC and the Bloomberg forward curves over this period. For context, Attachment 1 also includes the actual Bank of Canada 10-year GoC yield that manifested.

Despite OPG engaging Global Insight to understand the three issues highlighted above, Global Insight was unable to provide a satisfactory explanation thereof to OPG. As such, at the time of filing the Application, OPG could not adequately explain the variability in the forecasts nor changes in historical data observed in the Global Insight publications.

d) OPG considered several alternatives for forecasting the GoC rates for this Application, in addition to the chosen method of blending the BYFC with the Bloomberg forward rates.
First, OPG considered using Consensus Economics, which is another economist forecast. However, Consensus Economics does not forecast the 30-year GoC bond yield, which would not have allowed the inclusion of the 30-year tenor assumption in OPG's long-term debt forecast cost. As discussed in part (a) and part (b) above, this would have been inconsistent with OPG's actual experience and expectations and would have resulted in an inaccurate forecast.

Second, OPG considered reaching out to individual Canadian banks to obtain bespoke forecasts. However, given that the BYFC survey already sources individual forecasts from each of the same banks (and several international banks as well), and that the BYFC is readily available for viewing by any Bloomberg subscriber, OPG concluded that the simplicity and transparency of the BYFC would be superior to any bilaterally produced forecast. For example, the March 2026 BYFC survey had 12 different economists being surveyed for the 10-year GoC bond yield, and nine different economists for the 30-year GoC bond yield. This would be a greater number of forecasts than OPG would reasonably be able to access on an individual basis, making the BYFC's consensus view amongst a number of forecasts superior in reducing the inherent possibility of a single forecast's bias and error. For these reasons, OPG did not pursue obtaining bespoke forecasts from individual banks.

Lastly, OPG considered adopting the Bloomberg forward curve as the sole forecast source. The benefit of incorporating Bloomberg forward rate into the forecast is that these curves are derived mathematically from transactable rates in highly liquid and transparent spot markets, rather than econometric models, and therefore reflect more diverse views from the trading and investment community. In more unpredictable markets, particularly at times of global geopolitical uncertainty that has manifested throughout 2025 and into 2026, econometric models may be slower to respond to such events, as they are typically trained on historical information. However, while the sole use of the forward rates for forecasting purposes is a viable alternative, OPG ultimately decided that combining this source with a consensus econometric forecast represented a broader, more balanced approach, while providing some continuity with past payment amounts proceedings through the use of an econometric model.

For clarity, OPG did not consider using the DLTDR for forecasting purposes for the reasons discussed in Ex. L-C1-Staff-028.

AMPCO Interrogatory #073

Interrogatory

Reference:
D2-4-1 p.8 footnote 7

Question(s):

a) Please provide the materials provided to OPG's Board of Directors that resulted in the November 2021 OPG Board of Directors' decision to proceed with the capital project.

b) Please provide any documentation provided by OPG's Board of Directors regarding its approval of the project.

Response

a) and b)

Refer to Ex. L-D2-SEC-098.

SEC Interrogatory #089

Interrogatory

Reference:
D2-3-8

Question(s):

With respect to the business cases and budgets:

a) Please provide a table that shows every cost estimate (e.g. internal, class, release, and phase) developed for the project, broken down by bundles/category. For each estimate, please provide the date, phase, and reason for the change.

b) Please provide a copy of each business case (for each class and release) developed for the PRP.

Response

a) and b)
This interrogatory seeks materials and cost estimates that have been superseded by the Release Quality Estimate provided at Ex. D2-3-8, Attachment 1. In accordance with the Motions Resolution letter filed on May 4, 2026, OPG provided certain cost information in relation to the Initiation Phase and Definition Phase of the Pickering Refurbishment Program at Ex. L-D2-SEC-080. OPG otherwise declines to provide the requested information on the basis of relevance. The Release Quality Estimate is the basis on which OPG is undertaking the work and is the basis of the application before the OEB. Any previous materials and costs estimates, or evolution of cost estimates, are not relevant to evaluating the issues in this proceeding.

SEC Interrogatory #097

Interrogatory

Reference:
D2-4-1, p. 5

Question(s):

With respect to the selection of BWRX-300 as the specific technology:

a) Please provide a detailed explanation of the technology selection process.

b) Please provide all materials provided to the OPG Board of Directors regarding the selection of the BWRX-300 as the specific technology.

c) Please provide a copy of any internal document that was created that provides a summary of the outcome of the selection process, a review of the other potential technologies that were considered, and a recommendation for the selection of the BWRX-300.

d) Did OPG undertake any third-party reviews of the selection process? If so, please provide a copy of their report (or similar documents).

e) Please confirm that OPG is the first company to construct a BWRX-300 reactor.

f) As part of the selection process, did OPG (or related entities) receive any preferential benefits with GE-Hitachi regarding preferential benefits to OPG for being the first company to construct a BWRX-300 reactor? If so, please provide details.

Response

a) A detailed explanation of the technology selection process was provided at EB-2023-0336, Ex. H1-1-1, p. 39 and EB-2023-0336, Ex. L-H-CCC-08 including Attachment 1 (confidential). The associated costs were decided in EB-2023-0336, in which OPG sought cost recovery for that process. The Applicants are not seeking recovery of any costs related to the DNNP technology selection process in this proceeding. The issue of DNNP technology selection is not within the scope of the current proceeding and the Applicants will not be refiling the EB-2023-0336 materials.

b) Materials provided to the OPG Board of Directions regarding the selection of the BWRX-300 as the specific technology were provided in EB-2023-0336 in response to Ex. L-H-CCC-08, Attachment 2 (confidential). For the reasons set out in part a) above, the Applicants will not be refiling these materials. Additionally, refer to Ex. L-D2-SEC-098.

c) and d)

Refer to part a).

e) The Applicants confirm that OPG is the first company to receive a construction licence and commence construction of a BWRX-300 reactor. The construction is continuing through DNNP LP.

f) Refer to Ex. L-A1-CCC-012, part a) (iii).

Numbers may not add due to rounding.

D3-1-1 Table 2 (Annual Business Plan Version)
Comparison of Capital Expenditures - Support Services ($M) 2020-2031
(Capital Expenditures Impacting OPG Rate Base or Asset Service Fees)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	2021 OEB Approved	(f)-(d) Change	2021 Actual	2022 per 2022-2026 BP	(i)-(g) Change	2022 Actual	2023 per 2023-2026 BP	(l)-(j) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capital Projects (Allocated)												
1	**IT Portfolio[1]**	6.2	94.8	101.0	7.4	97.2	104.6	93.8	3.2	96.9	121.0	(4.6)	116.4
2	**Real Estate**	8.0	12.0	20.0	8.0	16.3	24.3	34.3	(6.3)	27.9	23.1	14.3	37.4
3	**Subtotal Capital Projects (Allocated)**	14.2	106.8	121.0	15.4	113.5	128.9	128.0	(3.2)	124.9	144.1	9.6	153.8
4	**IT Portfolio (Unallocated)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Subtotal Capital Projects**	14.2	106.8	121.0	15.4	113.5	128.9	128.0	(3.2)	124.9	144.1	9.6	153.8
6	**Microsoft Enterprise Agreement**	0.0	23.1	23.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Clarington Corporate Campus[2]**	0.0	0.0	0.0	0.0	0.0	0.0	51.7	(51.7)	0.0	0.0	0.0	0.0
8	**Corporate Headquarters[3]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	12.0	61.4
9	**Subtotal**	0.0	23.1	23.1	0.0	0.0	0.0	51.7	(51.7)	0.0	49.4	12.0	61.4
10	**Enterprise System Modernization Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Enterprise System Modernization Projects-Unallocated**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**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
13	**DNNP Operational Readiness Technology Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**DNNP Operational Readiness Technology Projects- Unallocated Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**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
16	**Total (line 5 + line 9 + line 12 + line 15)**	14.2	129.8	144.0	15.4	113.5	128.9	179.7	(54.8)	124.9	193.5	21.6	215.1

Line No.	Business Unit	2024 per 2024-2026 BP	(c)-(a) Change	2024 Actual	2025 per 2025-2031 BP[4]	(f)-(d) Change	2025 Budget[4]	2026 per 2025-2031 BP	(i)-(g) Change	2026 Budget	2022-2026 Actuals & Budget	(l)-(j) Change	2027-2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capital Projects (Allocated)												
17	**IT Portfolio[1]**	96.0	(3.3)	92.7	103.0	0.0	103.0	33.4	0.0	33.4	442.4	(384.8)	57.6
18	**Real Estate**	23.4	11.3	34.7	21.6	14.5	36.1	76.6	(0.0)	76.6	212.8	44.3	257.1
19	**Subtotal Capital Projects (Allocated)**	119.5	8.0	127.4	124.6	14.5	139.1	110.0	0.0	110.0	655.2	(340.5)	314.7
20	**IT Portfolio (Unallocated)**	0.0	0.0	0.0	0.0	0.0	0.0	63.2	0.0	63.2	63.2	290.9	354.1
21	**Subtotal Capital Projects**	119.5	8.0	127.4	124.6	14.5	139.1	173.2	0.0	173.2	718.4	(49.6)	668.8
22	**Microsoft Enterprise Agreement**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Clarington Corporate Campus[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
24	**Corporate Headquarters[3]**	45.2	(1.1)	44.1	71.5	13.8	85.3	0.0	0.0	0.0	190.8	(190.8)	0.0
25	**Subtotal**	45.2	(1.1)	44.1	71.5	13.8	85.3	0.0	0.0	0.0	190.8	(190.8)	0.0
26	**Enterprise System Modernization Projects**	0.0	0.0	0.0	12.2	(0.0)	12.2	48.1	(0.0)	48.1	60.3	(2.0)	58.3
27	**Enterprise System Modernization Projects-Unallocated**	0.0	0.0	0.0	0.0	0.0	0.0	10.3	(0.0)	10.3	10.3	224.1	234.4
28	**Subtotal**	0.0	0.0	0.0	12.2	(0.0)	12.2	58.5	(0.0)	58.5	70.6	222.1	292.7
29	**DNNP Operational Readiness Technology Projects**	0.0	0.0	0.0	15.1	0.0	15.1	15.3	0.0	15.3	30.4	7.9	38.3
30	**DNNP Operational Readiness Technology Projects- Unallocated Projects**	0.0	0.0	0.0	10.3	0.0	10.3	30.1	(0.0)	30.1	40.4	2.4	42.8
31	**Subtotal**	0.0	0.0	0.0	25.4	0.0	25.4	45.3	(0.0)	45.3	70.7	10.4	81.1
32	**Total (line 21 + line 25 + line 28 + line 31)**	164.7	6.9	171.5	233.8	28.3	262.1	277.0	(0.0)	277.0	1,050.6	(8.0)	1,042.6

Notes:

1. Expenditures include a project with a cloud computing arrangements (Ex. D3-1-2, p. 3, footnote 1) .
2. Clarington Corporate Campus (EB-2020-0290) was cancelled for a preferrable alternative and written off to Project OM&A. The cancelled project is discussed further in Ex. D3-1-1 Section 3.2.
3. Corporate Headquarters includes the cost to acquire the building and associated renovation. The acquisition cost excludes costs associated with undeveloped land of $51.1M. For purposes of comparison, an estimate of $48.1M for the proportionate land costs in the business plan budget was removed.
4. As noted in Ex. A2-2-1, p. 17, footnote 18, certain 2025 Budget information in the pre-filed evidence was presented on the basis of 2025 current forecast information from the 2025-2031 Business Plan, rather than budget values. Thus, Col. (f) which was included in the pre-filed evidence, reflects the 2025 current forecast information from the 2025-2031 Business Plan, whereas Col. (d) reflects the 2025 budget from the 2025-2031 Business Plan.

Numbers may not add due to rounding.

D3-1-2 Table 5a (Annual Business Plan Version)

Comparison of In-Service Capital Additions - Support Services ($M) 2020-2028

Line No.	Business Unit	2020 OEB Approved[1]	(c)-(a) Change	2020 Actual	2021 OEB Approved[1]	(f)-(d) Change	2021 Actual	2022 per 2022-2026 BP	(i)-(g) Change	2022 Actual	2023 per 2023-2026 BP	(l)-(j) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**IT - Nuclear Rate Base**	3.7	18.0	21.7	2.2	37.7	39.9	30.3	(3.7)	26.6	26.6	(3.4)	23.1
2	**IT - Regulated Hydroelectric Rate Base**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**IT - Renewable Generation Joint Use Assets**	0.0	12.9	12.9	0.0	6.1	6.1	2.1	(0.1)	2.0	1.8	0.5	2.3
4	**IT - Asset Service Fee**	17.0	51.6	68.6	17.0	48.0	65.0	53.0	24.7	77.7	77.9	(20.0)	57.9
5	**Subtotal**	20.7	82.4	103.1	19.2	91.8	111.0	85.3	20.9	106.2	106.3	(23.0)	83.3
6	**Real Estate - Nuclear Rate Base**	1.0	11.5	12.5	1.0	20.3	21.3	35.5	(12.7)	22.8	27.8	8.1	35.9
7	**Real Estate - Asset Service Fee**	3.0	0.5	3.5	3.0	(0.6)	2.4	0.0	1.1	1.1	0.0	2.3	2.3
8	**Real Estate - Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Subtotal**	4.0	12.0	16.0	4.0	19.6	23.6	35.5	(11.6)	23.9	27.8	10.4	38.2
10	**Microsoft Enterprise Agreement**	0.0	22.9	22.9	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
11	**Clarington Corporate Campus[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
12	**Corporate Headquarters[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0	(15.3)	7.7
13	**Subtotal**	0.0	22.9	22.9	0.0	0.1	0.1	0.0	0.0	0.0	23.0	(15.3)	7.7
14	**Enterprise System Modernization Projects- ASF**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**DNNP Operational Readiness Technology Projects- DNNP Asset Service Fee**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Minor Fixed Assets**	1.2	2.4	3.6	1.2	2.0	3.2	3.9	0.8	4.8	3.9	(0.0)	3.9
17	**In-Service Capital Additions Before Adjustments**	25.9	119.8	145.7	24.4	113.5	137.9	124.8	10.2	134.9	161.0	(27.9)	133.2
18	**OEB/Settlement Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total In-Service Capital Additions Including Adjustments**	25.9	119.8	145.7	24.4	113.5	137.9	124.8	10.2	134.9	161.0	(27.9)	133.2

Line No.	Business Unit	2024 per 2024-2026 BP	(c)-(a) Change	2024 Actual	2025 per 2025-2031 BP[3]	(f)-(d) Change	2025 Budget[3]	2026 per 2026-2031 BP	(i)-(g) Change	2026 Budget	2027 Plan	(l)-(j) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
20	**IT - Nuclear Rate Base**	16.4	13.4	29.8	19.0	1.8	20.8	21.5	0.0	21.5	26.4	(0.2)	26.2
21	**IT - Regulated Hydroelectric Rate Base**	0.0	0.1	0.1	0.0	2.0	2.0	0.5	(0.0)	0.5	1.5	0.0	1.5
22	**IT - Renewable Generation Joint Use Assets**	3.1	(2.4)	0.7	6.2	(2.2)	4.0	1.4	(0.0)	1.4	1.1	(1.1)	0.0
23	**IT - Asset Service Fee**	74.9	(25.3)	49.6	102.9	3.5	106.4	49.6	0.0	49.6	66.1	(12.5)	53.6
24	**Subtotal**	94.4	(14.1)	80.3	128.1	5.1	133.3	72.9	0.0	73.0	95.1	(13.8)	81.3
25	**Real Estate - Nuclear Rate Base**	30.3	(1.2)	29.1	12.3	(0.6)	11.6	15.0	0.0	15.0	107.5	(71.5)	36.0
26	**Real Estate - Asset Service Fee**	0.0	0.5	0.5	11.5	(6.8)	4.7	0.2	0.0	0.2	27.6	(26.2)	1.4
27	**Real Estate - Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.1	(30.1)	0.0
28	**Subtotal**	30.3	(0.7)	29.6	23.8	(7.4)	16.4	15.2	0.0	15.2	165.2	(127.8)	37.4
29	**Microsoft Enterprise Agreement**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Clarington Corporate Campus[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
33	**Corporate Headquarters[2]**	0.0	0.0	0.0	173.7	9.4	183.1	0.0	0.0	0.0	0.0	0.0	0.0
34	**Subtotal**	0.0	0.0	0.0	173.7	9.4	183.1	0.0	0.0	0.0	0.0	0.0	0.0
35	**Enterprise System Modernization Projects- ASF**	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	4.0	0.0	89.1	89.1
36	**DNNP Operational Readiness Technology Projects- DNNP Asset Service Fee**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	**Minor Fixed Assets**	4.0	0.5	4.5	1.6	4.4	6.0	7.0	0.0	7.0	9.0	0.0	9.0
38	**In-Service Capital Additions Before Adjustments**	128.6	(14.3)	114.3	327.3	11.5	338.8	99.2	0.0	99.2	269.3	(52.5)	216.8
39	**OEB/Settlement Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total In-Service Capital Additions Including Adjustments**	128.6	(14.3)	114.3	327.3	11.5	338.8	99.2	0.0	99.2	269.3	(52.5)	216.8

Notes:

1. Clarington Corporate Campus (EB-2020-0290) was cancelled for a preferrable alternative and written off to Project OM&A. The cancelled project is discussed further in Ex. D3-1-1 Section 3.2.
2. Corporate Headquarters includes the cost to acquire the building and associated renovation. The acquisition cost excludes costs associated with undeveloped land.
3. As noted in Ex. A2-2-1, p. 17, footnote 18, certain 2025 Budget information in the pre-filed evidence was presented on the basis of 2025 current forecast information from the 2025-2031 Business Plan, rather than budget values. Thus, Col. (f) which was included in the pre-filed evidence, reflects the 2025 current forecast information from the 2025-2031 Business Plan, whereas Col. (d) reflects the 2025 budget from the 2025-2031 Business Plan.

Numbers may not add due to rounding.

D3-1-2 Table 5b (Annual Business Plan Version)
Comparison of In-Service Capital Additions - Support Services ($M) 2028-2031

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan	2022-2026 Actuals & Budget	(j)-(h) Change	2027-2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**IT - Nuclear Rate Base**	26.2	8.2	34.4	(13.1)	21.3	(5.3)	16.0	121.9	2.4	124.3
2	**IT - Regulated Hydroelectric Rate Base**	1.5	0.0	1.5	0.0	1.5	0.0	1.5	2.6	4.9	7.5
3	**IT - Renewable Generation Joint Use Assets**[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	(1.0)	1.1
4	**IT - Asset Service Fee**	53.6	(6.2)	47.5	(6.4)	41.1	5.2	46.3	341.2	(86.6)	254.6
5	**Subtotal**	81.3	2.0	83.3	(19.4)	63.9	(0.1)	63.8	467.7	(80.3)	387.4
6	**Real Estate - Nuclear Rate Base**	36.0	(3.2)	32.7	17.3	50.1	(26.4)	23.7	114.5	135.5	250.0
7	**Real Estate - Asset Service Fee**	1.4	3.0	4.4	(4.0)	0.4	0.0	0.4	8.8	25.4	34.2
8	**Real Estate - Renewable Generation Joint Use Assets**[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.1	30.1
9	**Subtotal**	37.4	(0.2)	37.1	13.3	50.5	(26.4)	24.1	123.3	191.0	314.3
10	**Microsoft Enterprise Agreement**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
11	**Clarington Corporate Campus**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.8	(190.8)	0.0
13	**Subtotal**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.8	(190.8)	0.0
14	**Enterprise System Modernization Projects- ASF**	89.1	0.9	90.0	(58.3)	31.7	88.8	120.5	4.0	327.3	331.3
15	**DNNP Operational Readiness Technology Projects- DNNP Asset Service Fee**	0.0	0.0	0.0	132.6	132.6	(126.1)	6.5	0.0	139.2	139.2
16	**Minor Fixed Assets**	9.0	0.0	9.0	0.0	9.0	0.0	9.0	26.2	18.8	45.0
											0.0
17	**In-Service Capital Additions Before Adjustments**	216.8	2.8	219.5	68.2	287.7	(63.8)	223.9	812.1	405.2	1,217.2
18	**OEB/Settlement Adjustments**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total In-Service Capital Additions Including Adjustments**	216.8	2.8	219.5	68.2	287.7	(63.8)	223.9	812.1	405.1	1,217.2

Notes:

1 A 5-year average of the 2022-2026 actuals and budget in-service additions is used as a comparison to the 2027 plan amounts for Renewable Generation Joint Use Assets.

Numbers may not add due to rounding.

D3-1-1- Table 2 (2022-2026 Business Plan Version)
Comparison of Capital Expenditures - Support Services ($M) 2020-2031
(Capital Expenditures Impacting OPG Rate Base or Asset Service Fees)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	2021 OEB Approved	(f)-(d) Change	2021 Actual	2022 per 2022-2026 BP	(i)-(g) Change	2022 Actual	2023 per 2022-2026 BP	(l)-(j) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capital Projects (Allocated)												
1	**IT Portfolio[1]**	6.2	94.8	101.0	7.4	97.2	104.6	93.8	3.2	96.9	79.4	37.0	116.4
2	**Real Estate**	8.0	12.0	20.0	8.0	16.3	24.3	34.3	(6.3)	27.9	13.8	23.5	37.4
3	**Subtotal Capital Projects (Allocated)**	14.2	106.8	121.0	15.4	113.5	128.9	128.0	(3.2)	124.9	93.2	60.6	153.8
4	**IT Portfolio (Unallocated)[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
5	**Subtotal Capital Projects**	14.2	106.8	121.0	15.4	113.5	128.9	128.0	(3.2)	124.9	93.2	60.6	153.8
6	**Microsoft Enterprise Agreement[3]**	0.0	23.1	23.1	0.0	0.0	0.0	0.0	0.0	0.0	23.0	(23.0)	0.0
7	**Clarington Corporate Campus[4]**	0.0	0.0	0.0	0.0	0.0	0.0	51.7	(51.7)	0.0	92.3	(92.3)	0.0
8	**Corporate Headquarters[5]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.4	61.4
9	**Subtotal**	0.0	23.1	23.1	0.0	0.0	0.0	51.7	(51.7)	0.0	115.3	(54.0)	61.4
10	**Enterprise System Modernization Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Enterprise System Modernization Projects-Unallocated**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**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
13	**DNNP Operational Readiness Technology Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**DNNP Operational Readiness Technology Projects- Unallocated Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**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
16	**Total (line 5 + line 9 + line 12 + line 15)**	14.2	129.8	144.0	15.4	113.5	128.9	179.7	(54.8)	124.9	208.5	6.6	215.1

Line No.	Business Unit	2024 per 2022-2026 BP	(c)-(a) Change	2024 Actual	2025 per 2022-2026 BP[6]	(f)-(d) Change	2025 Budget[6]	2026 per 2022-2026 BP	(i)-(g) Change	2026 Budget	2022-2026 Actuals & Budget	(l)-(j) Change	2027-2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capital Projects (Allocated)												
17	**IT Portfolio[1]**	80.2	12.5	92.7	80.0	23.0	103.0	79.2	(45.8)	33.4	442.4	(384.8)	57.6
18	**Real Estate**	1.5	33.2	34.7	3.8	32.3	36.1	5.2	71.4	76.6	212.8	44.3	257.1
19	**Subtotal Capital Projects (Allocated)**	81.7	45.7	127.4	83.8	55.3	139.1	84.4	25.7	110.0	655.2	(340.5)	314.7
20	**IT Portfolio (Unallocated)[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.2	63.2	63.2	290.9	354.1
21	**Subtotal Capital Projects**	81.7	45.7	127.4	83.8	55.3	139.1	84.4	88.8	173.2	718.4	(49.6)	668.8
22	**Microsoft Enterprise Agreement[3]**	0.0	0.0	0.0	0.0	0.0	0.0	23.0	(23.0)	0.0	0.0	0.0	0.0
23	**Clarington Corporate Campus[4]**	51.8	(51.8)	0.0	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Corporate Headquarters[5]**	0.0	44.1	44.1	0.0	85.3	85.3	0.0	0.0	0.0	190.8	(190.8)	0.0
25	**Subtotal**	51.8	(7.7)	44.1	0.5	84.8	85.3	23.0	(23.0)	0.0	190.8	(190.8)	0.0
26	**Enterprise System Modernization Projects**	0.0	0.0	0.0	0.0	12.2	12.2	0.0	48.1	48.1	60.3	(2.0)	58.3
27	**Enterprise System Modernization Projects-Unallocated**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.3	10.3	10.3	224.1	234.4
28	**Subtotal**	0.0	0.0	0.0	0.0	12.2	12.2	0.0	58.5	58.5	70.6	222.1	292.7
29	**DNNP Operational Readiness Technology Projects**	0.0	0.0	0.0	0.0	15.1	15.1	0.0	15.3	15.3	30.4	7.9	38.3
30	**DNNP Operational Readiness Technology Projects- Unallocated Projects**	0.0	0.0	0.0	0.0	10.3	10.3	0.0	30.1	30.1	40.4	2.4	42.8
31	**Subtotal**	0.0	0.0	0.0	0.0	25.4	25.4	0.0	45.3	45.3	70.7	10.4	81.1
32	**Total (line 21 + line 25 + line 28 + line 31)**	133.6	38.0	171.5	84.3	177.7	262.1	107.4	169.6	277.0	1,050.6	(8.0)	1,042.6

Notes:
1. Expenditures include a project with a cloud computing arrangements (Ex. D3-1-2, p. 3, footnote 1) .
2. Portfolio Projects information per the 2022-2026 Business Plan is not readily available to separate unallocated projects.
3. Variance in 2023 and 2026 due to updated accounting treatment of these costs as OM&A (Ex. D3-1-1, s. 3.1.4)
4. Clarington Corporate Campus (EB-2020-0290) was cancelled for a preferrable alternative and written off to Project OM&A. The cancelled project is discussed further in Ex. D3-1-1 Section 3.2.
5. Corporate Headquarters includes the cost to acquire the building and associated renovation. The acquisition cost excludes costs associated with undeveloped land of $51.1M.
6. As noted in Ex. A2-2-1, p. 17, footnote 18, certain 2025 Budget information in the pre-filed evidence was presented on the basis of 2025 current forecast information from the 2025-2031 Business Plan, rather than budget values. Thus, Col. (f) which was included in the pre-filed evidence, reflects the 2025 current forecast information from the 2025-2031 Business Plan, whereas Col. (d) reflects the 2025 budget from the 2022-2026 Business Plan.

Numbers may not add due to rounding.

D3-1-2 Table 5a (2022-2026 Business Plan Version)
Comparison of In-Service Capital Additions - Support Services ($M) 2020-2028

Line No.	Business Unit	2020 OEB Approved[1]	(c)-(a) Change	2020 Actual	2021 OEB Approved[1]	(f)-(d) Change	2021 Actual	2022 per 2022-2026 BP	(i)-(g) Change	2022 Actual	2023 per 2022-2026 BP	(l)-(j) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**IT - Nuclear Rate Base**	3.7	18.0	21.7	2.2	37.7	39.9	30.3	(3.7)	26.6	22.5	0.7	23.1
2	**IT - Regulated Hydroelectric Rate Base**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**IT - Renewable Generation Joint Use Assets**	0.0	12.9	12.9	0.0	6.1	6.1	2.1	(0.1)	2.0	3.9	(1.6)	2.3
4	**IT - Asset Service Fee**	17.0	51.6	68.6	17.0	48.0	65.0	53.0	24.7	77.7	57.0	0.9	57.9
5	**Subtotal**	20.7	82.4	103.1	19.2	91.8	111.0	85.3	20.9	106.2	83.3	(0.0)	83.3
6	**Real Estate - Nuclear Rate Base**	1.0	11.5	12.5	1.0	20.3	21.3	35.5	(12.7)	22.8	19.5	16.4	35.9
7	**Real Estate - Asset Service Fee**	3.0	0.5	3.5	3.0	(0.6)	2.4	0.0	1.1	1.1	0.0	2.3	2.3
8	**Real Estate - Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Subtotal**	4.0	12.0	16.0	4.0	19.6	23.6	35.5	(11.6)	23.9	19.5	18.7	38.2
10	**Microsoft Enterprise Agreement[1]**	0.0	22.9	22.9	0.0	0.1	0.1	0.0	0.0	0.0	23.0	(23.0)	0.0
11	**Clarington Corporate Campus[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
12	**Corporate Headquarters[3]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7	7.7
13	**Subtotal**	0.0	22.9	22.9	0.0	0.1	0.1	0.0	0.0	0.0	23.0	(15.3)	7.7
14	**Enterprise System Modernization Projects- ASF**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Enterprise System Modernization Projects-Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**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
17	**DNNP Operational Readiness Technology Projects-DNNP Asset Service Fee**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**Minor Fixed Assets**	1.2	2.4	3.6	1.2	2.0	3.2	3.9	0.8	4.8	3.9	(0.0)	3.9
19	**In-Service Capital Additions Before Adjustments**	25.9	119.8	145.7	24.4	113.5	137.9	124.8	10.2	134.9	129.7	3.4	133.2
20	**OEB/Settlement Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Total In-Service Capital Additions Including Adjustments**	25.9	119.8	145.7	24.4	113.5	137.9	124.8	10.2	134.9	129.7	3.4	133.2

Line No.	Business Unit	2024 per 2022-2026 BP	(c)-(a) Change	2024 Actual	2025 per 2022-2026 BP[4]	(f)-(d) Change	2025 Budget[4]	2026 per 2022-2026 BP	(i)-(g) Change	2026 Budget	2027 Plan	(l)-(j) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
22	**IT - Nuclear Rate Base**	38.9	(9.1)	29.8	33.7	(12.9)	20.8	25.6	(4.1)	21.5	26.4	(0.2)	26.2
23	**IT - Regulated Hydroelectric Rate Base**	0.0	0.1	0.1	0.0	2.0	2.0	0.0	0.5	0.5	1.5	0.0	1.5
24	**IT - Renewable Generation Joint Use Assets**	2.8	(2.1)	0.7	5.9	(1.9)	4.0	10.4	(9.0)	1.4	1.1	(1.1)	0.0
25	**IT - Asset Service Fee**	34.6	15.0	49.6	37.3	69.2	106.4	38.0	11.7	49.6	66.1	(12.5)	53.6
26	**Subtotal**	76.3	4.0	80.3	76.8	56.5	133.3	74.0	(1.0)	73.0	95.1	(13.8)	81.3
27	**Real Estate - Nuclear Rate Base**	1.5	27.6	29.1	1.0	10.7	11.6	5.2	9.8	15.0	107.5	(71.5)	36.0
28	**Real Estate - Asset Service Fee**	0.0	0.5	0.5	0.0	4.7	4.7	0.0	0.2	0.2	27.6	(26.2)	1.4
29	**Real Estate - Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.1	(30.1)	0.0
30	**Subtotal**	1.5	28.1	29.6	1.0	15.4	16.4	5.2	10.0	15.2	165.2	(127.8)	37.4
31	**Microsoft Enterprise Agreement[1]**	0.0	0.0	0.0	0.0	0.0	0.0	23.0	(23.0)	0.0	0.0	0.0	0.0
32	**Clarington Corporate Campus[2]**	197.5	(197.5)	0.0	2.5	(2.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Corporate Headquarters[3]**	0.0	0.0	0.0	0.0	183.1	183.1	0.0	0.0	0.0	0.0	0.0	0.0
34	**Subtotal**	197.5	(197.5)	0.0	2.5	180.6	183.1	23.0	(23.0)	0.0	0.0	0.0	0.0
35	**Enterprise System Modernization Projects- ASF**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	0.0	89.1	89.1
36	**Enterprise System Modernization Projects-Renewable Generation Joint Use Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	**Subtotal**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	0.0	89.1	89.1
38	**DNNP Operational Readiness Technology Projects-DNNP Asset Service Fee**	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	**Minor Fixed Assets**	4.0	0.5	4.5	3.2	2.8	6.0	3.2	3.8	7.0	9.0	0.0	9.0
40	**In-Service Capital Additions Before Adjustments**	279.2	(165.0)	114.3	83.5	255.3	338.8	105.4	(6.2)	99.2	269.3	(52.5)	216.8
41	**OEB/Settlement Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	**Total In-Service Capital Additions Including Adjustments**	279.2	(165.0)	114.3	83.5	255.3	338.8	105.4	(6.2)	99.2	269.3	(52.5)	216.8

Notes:
1. Variance in 2023 and 2026 due to updated accounting treatment of these costs as OM&A (Ex. D3-1-1, s. 3.1.4).
2. Clarington Corporate Campus (EB-2020-0290) was cancelled for a preferrable alternative and written off to Project OM&A. The cancelled project is discussed further in Ex. D3-1-1 Section 3.2.
3. Corporate Headquarters includes the cost to acquire the building and associated renovation. The acquisition cost excludes costs associated with undeveloped land.
4. As noted in Ex. A2-2-1, p. 17, footnote 18, certain 2025 Budget information in the pre-filed evidence was presented on the basis of 2025 current forecast information from the 2025-2031 Business Plan, rather than budget values. Thus, Col. (f) which was included in the pre-filed evidence, reflects the 2025 current forecast information from the 2025-2031 Business Plan, whereas Col. (d) reflects the 2025 budget from the 2022-2026 Business Plan.

Numbers may not add due to rounding.

D3-1-2 Table 5b (Annual Business Plan Version)
Comparison of In-Service Capital Additions - Support Services ($M) 2028-2031

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan	2022-2026 Actuals & Budget	(j)-(h) Change	2027-2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**IT - Nuclear Rate Base**	26.2	8.2	34.4	(13.1)	21.3	(5.3)	16.0	121.9	2.4	124.3
2	**IT - Regulated Hydroelectric Rate Base**	1.5	0.0	1.5	0.0	1.5	0.0	1.5	2.6	4.9	7.5
3	**IT - Renewable Generation Joint Use Assets**[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	(1.0)	1.1
4	**IT - Asset Service Fee**	53.6	(6.2)	47.5	(6.4)	41.1	5.2	46.3	341.2	(86.6)	254.6
5	**Subtotal**	81.3	2.0	83.3	(19.4)	63.9	(0.1)	63.8	467.7	(80.3)	387.4
6	**Real Estate - Nuclear Rate Base**	36.0	(3.2)	32.7	17.3	50.1	(26.4)	23.7	114.5	135.5	250.0
7	**Real Estate - Asset Service Fee**	1.4	3.0	4.4	(4.0)	0.4	0.0	0.4	8.8	25.4	34.2
8	**Real Estate - Renewable Generation Joint Use Assets**[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.1	30.1
9	**Subtotal**	37.4	(0.2)	37.1	13.3	50.5	(26.4)	24.1	123.3	191.0	314.3
10	**Microsoft Enterprise Agreement**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
11	**Clarington Corporate Campus**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.8	(190.8)	0.0
13	**Subtotal**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.8	(190.8)	0.0
14	**Enterprise System Modernization Projects- ASF**	89.1	0.9	90.0	(58.3)	31.7	88.8	120.5	4.0	327.3	331.3
15	**DNNP Operational Readiness Technology Projects- DNNP Asset Service Fee**	0.0	0.0	0.0	132.6	132.6	(126.1)	6.5	0.0	139.2	139.2
16	**Minor Fixed Assets**	9.0	0.0	9.0	0.0	9.0	0.0	9.0	26.2	18.8	45.0
											0.0
17	**In-Service Capital Additions Before Adjustments**	216.8	2.8	219.5	68.2	287.7	(63.8)	223.9	812.1	405.2	1,217.2
18	**OEB/Settlement Adjustments**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total In-Service Capital Additions Including Adjustments**	216.8	2.8	219.5	68.2	287.7	(63.8)	223.9	812.1	405.1	1,217.2

Notes:
1 A 5-year average of the 2022-2026 actuals and budget in-service additions is used as a comparison to the 2027 plan amounts for Renewable Generation Joint Use Assets.

COMPARISON OF PRODUCTION FORECASTS – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of actual and forecast nuclear production for 2020-2031, in support of the approval of OPG's nuclear facilities' production forecast for the IR term. In addition, this evidence separately sets out the production forecast for the Darlington New Nuclear Program ("DNNP") facilities, the first unit of which will enter commercial operation during the IR term.

2.0 OPG NUCLEAR FACILITIES

2.1 Overview

Variances between actual and forecast production in the 2022-2026 term are primarily the result of the successful execution of the Darlington Refurbishment Program ("DRP"), including the implementation of lessons learned and unit over unit efficiencies, and the Province of Ontario's decision to extend Pickering Units 5-8 operations from 2025 to 2026.[1] Other reasons for variances are attributed to changes in the following: station planned outage ("PO") days,[2] forced outages ("FO"), planned or forced derates and unbudgeted POs. Variances may also arise due to station consumption, grid losses and impacts on thermal performance resulting from high lake water temperature.

Period-over-period variances are presented in Ex. E2-1-2, Tables 1a and 1b, and are explained below.

2.2 Period-Over-Period Changes – IR Term

As discussed in Ex. E2-1-1, Section 3.0, Pickering will be fully offline as of September 30, 2026. While Units 1 and 4 have ended commercial operation, Units 5-8 will transition to

[1] Under *Ontario Regulation 53/05*, OPG will return to ratepayers net revenues generated between January 1, 2026, to September 30, 2026, resulting from the extended operations of Pickering Units 5-8. See Ex. H1-1-1, Section 5.28, for information regarding the Pickering B Variance Account.

[2] PO days excludes a) outage days for Darlington units out of service during refurbishment, and b) outage equivalent planned derate days.

refurbishment, with Unit 5 returning to service towards the end of the IR term in May 2031. Until such point, there is no Pickering station generation during the IR term.

Also as discussed in Ex. E2-1-1, the DRP will conclude in 2026, with all four Darlington units operating throughout the IR term for the first time since 2016. Darlington's generation is impacted during this IR term by a four-unit vacuum building outage in 2027, and major equipment replacements and rehabilitations works requiring extended outages during the IR term as discussed below.

2027 Plan versus 2026 OEB-Approved

The 2027 Plan nuclear production of 18.7 terawatt-hours ("TWh") is 3.2 TWh lower than the 2026 OEB-approved plan production of 21.9 TWh. Since both the 2027 Plan and 2026 OEB-approved do not include any Pickering generation, the lower 2027 Plan production relative to 2026 OEB-approved is attributed to Darlington:

- Higher production in 2027 Plan compared with 2026 OEB-approved due to the completion of the DRP in 2026. The 2026 OEB-approved plan assumed that the last Darlington Unit 4 refurbishment would be complete in October 2026 (288 days).
- Lower production in 2027 Plan due to higher PO days (316.5 days) required primarily to execute major equipment replacements and rehabilitation associated with the Primary Moisture Separator ("PMS") Replacement on all four Steam Generators in Darlington Unit 2 in 2027, as well as the Unit 2 Turbine Control and Auxiliary Systems Upgrade ("TG Controls") project being executed in parallel. Both projects are described in Ex. D2-1-3, Section 3.1.3.
- Lower production in 2027 Plan due to planned Vacuum Building Outage ("VBO"; 45.9 days per unit (137.7 days total)) which necessitates shutdown of Units 1, 3, and 4. OPG has strategically overlapped the VBO with the above Unit 2 planned outage to optimize the outages.
- Higher production in 2027 Plan due to 19.5 fewer FLR equivalent days in 2027 Plan when compared with 2026 OEB-approved.
- Higher production in 2027 Plan compared with 2026 OEB-approved due to Unit 3 bulkhead derates not required upon refurbishment completion (savings of 15.1 equivalent days).

2028 Plan versus 2027 Plan

The 2028 Plan nuclear production of 26.7 TWh is 8.0 TWh higher than the 2027 Plan production of 18.7 TWh. The higher production of 2028 relative to 2027 is primarily due to 371.2 fewer PO days at Darlington as summarized below:

- Higher production in 2028 Plan compared with 2027 Plan as VBO (137.7 days impact) is completed in 2027.
- Two POs in 2028 totaling 141.5 days as compared to two POs in 2027 totaling 375.0 days for the extended outage duration associated with the Unit 2 PMSR and TG Controls PO.

2029 Plan versus 2028 Plan

The 2029 Plan nuclear production of 25.1 TWh is 1.6 TWh lower than the 2028 Plan production of 26.7 TWh. The lower production in 2029 relative to 2028 is due to Darlington having 72.7 more PO days than in 2028 as summarized below:

- Three POs in 2029 totaling 214.1 days as compared to two POs totaling 141.5 days in 2028.

2030 Plan versus 2029 Plan

The 2030 Plan nuclear production of 26.8 TWh is 1.8 TWh higher than the 2029 Plan production of 25.1 TWh. The higher production in 2030 relative to 2029 is primarily due to higher production at Darlington as summarized below:

- Two POs in 2030 totaling 139.2 days as compared to three POs totaling 214.1 days in 2029.

2031 Plan versus 2030 Plan

The 2031 Plan nuclear production of 28.9 TWh is 2.1 TWh higher than the 2030 Plan production of 26.8 TWh. The higher production in 2031 relative to 2030 is primarily due to the return of Pickering Unit 5 from refurbishment and impacts of unit uprates at Darlington as summarized below:

- Higher production from Pickering Unit 5 return to service post-refurbishment in May 2031 (+1.9 TWh).

2.3 Period-Over-Period Changes – Bridge Years

2026 Budget versus 2026 OEB-Approved

The 2026 planned nuclear production of 32.5 TWh is 10.5 TWh higher than the 2026 OEB-approved production of 21.9 TWh. The higher 2026 planned production is primarily due to a combination of the following:

- Lower production at Darlington relative to OEB-approved primarily due to Unit 3 planned outage shifted from 2027 to 2026 and extended outage duration to conduct emergent work associated with the SG PMSR (-4.8 TWh).
- Higher production at Darlington due to planned early return to service of Unit 4 resulting in 183.0 fewer refurbishment days (+3.9 TWh).
- Higher production at Pickering due to Pickering Units 5-8 extended operation from January 1, 2026 to September 30, 2026 (+11.4 TWh).

2026 Budget versus 2025 Budget

The 2026 planned nuclear production of 32.5 TWh is 4.4 TWh lower than the 2025 planned nuclear production of 36.9 TWh. The lower 2026 planned production is primarily due to:

- Lower production at Pickering due to the planned shutdown of Units 5-8 on September 30, 2026 compared with entire year of production in 2025 (-4.4 TWh).

2025 Budget versus 2025 OEB-Approved

The 2025 planned nuclear production forecast of 36.9 TWh is 5.8 TWh higher than the 2025 OEB-approved production of 31.1 TWh. The higher 2025 planned production is primarily due to:

- Higher production at Darlington due to:
    - 107 fewer refurbishment days with Unit 1 having returned to service on November 27, 2024 versus OEB-approved assumption of April 18, 2025 (+2.2 TWh).
    - 182.0 fewer PO days due to shifting the Unit 2 Turbine Controls scope from 2025 to 2027 (see Ex. E2-1-1, Section 3.0 for further discussion) (+3.8 TWh).
    - 61 fewer post-refurbishment PO days attributed to Unit 3 (removal of 31-day post-refurbishment PO) and Unit 1 (reduced post-refurbishment PO from 55 days to 25 days) (+1.3 TWh). As a result of Unit 3's early return to service from refurbishment, a Unit 3

planned outage was shifted from 2027 into 2026, which eliminated the need for the Unit 3 post-refurbishment PO. Unit 1's reduced forecast for its post-refurbishment outage reflects operating experience from successful operation of Darlington Units 2, 3, and 1 post-refurbishments to-date.

- Lower planned production at Pickering primarily due to 80.0 additional planned PO days required to address Unit 6 equipment inspection and maintenance issues associated with life extension to September 31, 2026, partially offset by 5.0 fewer Equipment Aging Outage days (-0.8 TWh).
- Production Settlement adjustment (-0.9 TWh)

2025 Budget versus 2024 Actual

The 2025 planned nuclear production of 36.9 TWh is 3.9 TWh higher than the 2024 production of 33.0 TWh. The higher 2025 planned production is primarily due to:

- Higher planned production at Darlington (+9.4 TWh) due to:
  - 333 fewer refurbishment days (365 days in 2025 for Unit 4 compared to 698 days in 2024 for Units 1 and 4 combined);
  - 74 fewer PO days (25 days in 2025 planned production compared to 99 days in 2024); and
  - 41.2 fewer FLR equivalent days (38.6 days in 2025 planned production compared to 79.8 days in 2024).
- Lower planned production at Pickering (-5.5 TWh) primarily due to Units 1 and 4 end of commercial operations in 2024, with only Units 5-8 operating through 2025, partially offset by 172.7 fewer PO days in 2025 (110.3 PO days in the 2025 planned production compared to 283 PO days in 2024).

2.4 Period-Over-Period Changes – Historical Years

2024 Actual versus 2024 OEB-Approved

The 2024 actual nuclear production of 33.0 TWh is 1.1 TWh lower than the 2024 OEB-approved production of 34.1 TWh. The lower 2024 production is primarily due to a combination of the following:

- Lower production at Darlington due to 31.4 additional PO days in 2024 (86.4 days actual compared to 55 days in OEB-approved) reflecting a Unit 2 PO that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (-0.7 TWh).
- Lower production at Darlington due to higher actual FLR of 12.1% compared to 6.0% OEB-approved (-0.9 TWh), primarily due to the following forced outages
    - 26.3 days to repair boiler tube leak in Unit 3;
    - 4.4 days to address circulating cooling water pump issues on Unit 3;
    - 32.7 days to address loss of excitation related issues on Unit 2; and
    - 11.1 days to repair boiler feed water suction pipe leaks on Unit 1.
- Higher production at Darlington due to 35 fewer refurbishment days with Unit 1 available for commercial operations on November 27, 2024 (698 days actual for Units 1 and 4 combined compared to 733 days in OEB-approved). This was driven by improvements in refurbishment schedules based on implementing prior unit lessons learned (+0.7 TWh),
- Higher production at Darlington as no derates were required during installation of the Bulkhead to isolate Unit 4 for refurbishment from the operating units as well as during the removal of the Bulkhead while bringing Unit 1 from refurbishment (+0.8 TWh).
- Production Settlement adjustment (-0.7 TWh).

2024 Actual versus 2023 Actual

The 2024 nuclear production of 33.0 TWh is 3.1 TWh lower than the 2023 production of 36.1 TWh. The lower 2024 production is primarily due to lower production at Darlington (-3.0 TWh):

- 99 higher PO days (99 days in 2024 and no PO days in 2023);
- 69.3 higher FLR equivalent days (79.8 days in 2024 compared to 10.5 days in 2023); and
- 32 fewer refurbishment days (698 days in 2024 for Unit 1 and 4 combined compared to 730 days in 2023 for Units 1, 3, and 4 combined).

2023 Actual versus 2023 OEB-Approved

The 2023 actual nuclear production of 36.1 TWh is 4.9 TWh higher than the 2023 OEB-approved production of 31.2 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 108 fewer days required for refurbishment of Darlington units. Darlington Unit 3 was returned to service 166 days earlier than the OEB-approved plan as a result of the incorporation of significant operating experience and lessons learned from Unit 2 (+3.5 TWh). This was partially offset by the refurbishment of Darlington Unit 4 being advanced by 58 days to start immediately after Unit 3's return to service (-1.2 TWh).
- Higher production at Darlington due to fewer PO equivalent days, including a regular planned outage (82.2 days) that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (+1.8 TWh).

2023 Actual versus 2022 Actual

The 2023 nuclear production of 36.1 TWh is 0.8 TWh higher than the 2022 production of 35.3 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 45 fewer PO days in 2023 compared to 2022 (+0.9 TWh).
- Higher production at Darlington due to better FLR in 2023 compared to 2022 (+0.8 TWh).
- Lower production at Darlington due to 45 more refurbishment days at Darlington in 2023. There were 730.0 refurbishment days in 2023 with Unit 1 under refurbishment throughout the year (365 days) and Unit 4 refurbishment starting after Unit 3 returned to service. In comparison, there were 685.0 refurbishment days in 2022 as Unit 1 refurbishment began in February 2022 while Unit 3 refurbishment was already in progress (-0.9) TWh.

2022 Actual versus 2022 OEB-Approved

The nuclear production of 35.3 TWh in 2022 was 1.7 TWh higher than the 2022 OEB-approved production of 33.6 TWh. The higher 2022 production is primarily due to a combination of the following:

- Higher production at Darlington due primarily to:
  - 27.9 fewer PO days in 2022 compared to OEB-approved (+0.6 TWh);
  - Savings of 22.3 days as no derates were required during the installation of the Bulkhead to isolate Unit 1 for refurbishment from the operating units. This was the result

of implementation of Enriched Boric Acid project,[3] coupled with refurbishment schedule optimization based on lessons learned changes in operating unit fueling strategy (+0.5 TWh).

- Lower production at Darlington due to 40.6 more FLR equivalent days. Darlington's actual FLR was 7.5% versus 2022 OEB-approved of 2.1% (-0.8 TWh).
- Higher production at Pickering primarily due to 93.4 fewer PO days where regular PO were completed ahead of schedule with more efficient outage execution. One PO started later and was completed in early 2023 to mitigate execution overlap challenges of parallel execution of VBO (+1.2 TWh).

2022 Actual versus 2021 Actual

The 2022 nuclear production of 35.3 TWh is 4.3 TWh lower than the 2021 production of 39.6 TWh. The lower 2022 production is primarily due to a combination of the following:

- Lower production at Darlington due to 320.0 more refurbishment days in 2022. There were 365.0 refurbishment days in 2021 for Unit 3 compared with 685.0 refurbishment days in 2022 for Unit 3 during the entire year and Unit 1 refurbishment beginning in February (-6.7 TWh).
- Higher production at Darlington primarily due to 110.4 fewer PO days required in 2022 compared with 2021 (+2.3 TWh).

2021 Actual versus 2021 OEB-Approved

The 2021 nuclear production of 39.6 TWh was 4.2 TWh higher than the 2021 OEB-approved production of 35.4 TWh. The higher 2021 production is primarily due to a combination of the following:

- Higher production at Darlington due to 200.0 fewer refurbishment days. The OEB-approved production forecast reflected a six-month period when two units would be refurbished in parallel. Following revisions to the DRP schedule, this overlap began February 15, 2022 when Unit 1 began its refurbishment as opposed to June 15, 2021 (+4.2 TWh).

[3] The implementation of the Enriched Boric Acid project improves fueling reliability, allowing OPG to do longer maintenance windows on the fueling machine while a unit is operating.

- Lower production at Darlington due to 104.3 higher PO days. The OEB-approved production forecast reflected a post-refurbishment outage and a primary heat transport pump motor replacement mini outage, and no regular POs. In comparison, the 2021 Actual had two regular POs with 155.5 days. As a result of the revised DRP schedule, OPG had to move a Darlington Unit 1 outage from 2020 to 2021 and also add a PO in 2021 to support Unit 4 operation until its start of refurbishment (-2.2 TWh).
- Higher production at Pickering due to 227.3 fewer PO days. The Pickering VBO was moved to 2022 following Canadian Nuclear Safety Commission approval, accounting for 120.0 fewer PO days required at Pickering (+1.5 TWh).
- Higher production at Pickering due to the number of POs at Pickering being reduced from three to two due to the transition from a 24-month to a 30-month outage cycle (+1.3 TWh).

2021 Actual versus 2020 Actual

The 2021 nuclear production of 39.6 TWh is 4.3 TWh lower than the 2020 production of 43.9 TWh. The lower 2021 production is primarily due to a combination of the following:

- Lower production at Darlington primarily due to:
  - 122.5 higher PO days for 2021 (155.5 PO days) compared to 2020 (33 PO days) (-2.6 TWh).
  - 90 higher Darlington refurbishment days for 2021. Unit 3 was undergoing refurbishment for the entire 2021 compared with 275 refurbishment days in 2020 as Unit 2 completed refurbishment on June 4, 2020 and Unit 3 commenced refurbishment on September 3, 2020 (-1.9 TWh).
- Higher production at Pickering due to 114.6 fewer PO days for 2021 (335.5 PO days) compared with 2020 (450 PO days) (+1.4 TWh). This was partly offset by lower production at Pickering due to higher actual FLR for 2021 at 6.2% compared with 2020 FLR of 2.7% (-0.9 TWh).

2020 Actual versus 2020 OEB-Approved

The 2020 nuclear production of 43.9 TWh is 6.6 TWh higher than the 2020 OEB-approved production of 37.4 TWh. The higher 2020 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 91.1 fewer refurbishment days. In the 2020 OEB-approved production forecast, there was no gap between Unit 2 and Unit 3 refurbishments. Following revisions to the DRP schedule in response to the COVID-19 pandemic, there was a two-month gap between the return to service of Unit 2 and the start of the refurbishment of Unit 3 (+1.9 TWh).
- Higher production at Darlington due to the primary heat transport pump motor replacement mini outage included in EB-2016-0152 was cancelled as the work was completed in a prior year (+0.8 TWh).
- Higher production at Darlington from 150.2 fewer PO days due to a combination of the following:
  - The later return to service date for Unit 2 necessitated revisions to the outage schedule, which resulted in the rescheduling of the first Unit 2 post-refurbishment outage from 2020 to 2021 (+1.3 TWh); and
  - The shifting of the Unit 1 PO from September 2020 to February 2021 (+1.9 TWh);
  - Partly offset by a regulatory requirement to perform a single fuel channel replacement outage in advance of the Unit 3 refurbishment (-0.7 TWh).

3.0 DNNP FACILITIES

3.1 Overview

The first of four DNNP facilities' units is planned to be commercially available and generating starting in October 2030. Prior to this, there is no planned generation for the DNNP facilities. As such, there are no period-over-period comparison available for the historical or bridge years.

3.2 Period-Over-Period Changes – IR Term

2027 Plan versus 2026 OEB-Approved

There is no planned production from the DNNP facilities during this timeframe.

2028 Plan versus 2027 Plan

There is no planned production from the DNNP facilities during this timeframe.

2029 Plan versus 2028 Plan

There is no planned production from the DNNP facilities during this timeframe.

2030 Plan versus 2029 Plan

The 2030 DNNP facilities production forecast includes 0.5 TWh as DNNP facilities Unit 1 is planned to enter commercial operations in October 2030. There is no planned production during 2029 for the DNNP facilities.

2031 Plan versus 2030 Plan

The 2031 DNNP facilities production of 1.9 TWh is 1.4 TWh higher than 2030 Plan production of 0.5 TWh.

- There is higher production forecasted in 2031 with DNNP facilities' Unit 1 operating for a full year. This production increase is partly offset by the first PO at the DNNP facilities' Unit 1 as well as the warranty outage, both scheduled in 2031.

SEC Interrogatory #132

Interrogatory

Reference:
E1-2-1, p. 16

Question(s):

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

Response

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

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

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

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

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

Chart 1 – HIM Customer Benefit Modeling Analysis Outputs

Revenue		2026	2027
Export Revenue	$M	1.8	1.9

Cost		2026	2027
Ontario Zonal Price	$/MWh	0.08	(3.26)
Import Cost	$M	(10.5)	(114.2)
Non-OPG Gas Cost	$M	(29.7)	5.5
OPG Gas Cost	$M	(0.9)	(8.2)
Wind Cost	$M	2.9	1.7
Wind SBG Cost	$M	(2.9)	(1.7)
OPG Hydro SBG Cost	$M	(4.4)	(0.9)
OPG Hydro Cost	$M	4.1	(2.5)
Other non-OPG Cost (primarily Battery Energy Storage Systems	$M	(8.5)	(29.5)
OPG Biomass Cost	$M	(0.3)	(1.8)
Total Customer Cost (excluding HIM)	$M	(51.8)	(153.5)

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

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

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

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

Board Staff Interrogatory #148

Interrogatory

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

Preamble:

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

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

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

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

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

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

Question(s):

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

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

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

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

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

Response

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

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

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

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

	2020	2021	2022	2023	2024	2025 (Jan-Apr)
CMSC payments received[1]	18.4	36.2	115.0	31.2	27.8	13.2
Amount recorded in SBGVA	130.4	56.4	47.9	29.9	10.6	5.9

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

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

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

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

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

All data from finance reports/finance.

Numbers may not add due to rounding

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

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

Attachment 1

Numbers may not add due to rounding

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

	2008[1]	2009[1]	2010[2]	2011[3]	2012[3]	2013[4]	2014[5]	2015[5]	2016[4]	2017[6]	2018[6]	2019[6]
Pickering OEB Approved PO Days	179.0	176.0	436.0	304.0	247.0	303.5	292.9	287.9	401.6	541.6	530.8	517.2
Darlington OEB Approved PO Days	75.1	171.7	118.8	68.3	65.5	144.4	77.1	188.0	111.0	148.4	143.3	119.1
Pickering Variance (days) (Actual - OEB/Appr.)	(97.3)	83.7	4.9	61.7	105.3	84.9	47.4	102.6	61.1	(205.4)	(181.7)	(283.8)
Pickering Variance (TWh) (Actual - OEB/Appr.)	(1.2)	1.0	0.1	0.8	1.3	1.1	0.6	1.3	0.8	(2.5)	(2.2)	(3.5)
Darlington Variance (days) (Actual - OEB/Appr.)	(6.0)	10.5	18.2	(8.0)	(1.9)	39.9	14.9	86.5	(0.9)	(37.5)	(31.2)	(34.2)
Darlington Variance (TWh) (Actual - OEB/Appr.)	(0.1)	0.2	0.4	(0.2)	(0.0)	0.8	0.3	1.8	(0.0)	(0.8)	(0.7)	(0.7)
Total Variance (TWh)	(1.3)	1.3	0.4	0.6	1.3	1.9	0.9	3.1	0.7	(3.3)	(2.9)	(4.2)
Revenue Rate ($/MWh) [9]	53.0	53.0	53.0	51.5	51.5	51.5	52.8	59.3	59.3	70.2	78.6	77.0
Revenue Deficiency ($M) [10, 12]	(50.2)	62.4	21.8	28.1	59.3	89.2	43.8	170.4	40.5	(219.2)	(215.9)	(308.6)

	2020[6]	2021[6]	2022[7]	2023[7]	2024[7]	2025[7]	2026[7]	2027[8]	2028[8]	2029[8]	2030[8]	2031[8]
Pickering OEB Approved PO Days	498.9	562.8	487.2	371.1	270.2	35.0	0.0	0.0	0.0	0.0	0.0	55.0
Darlington OEB Approved PO Days	183.2	51.2	73.0	112.2	55.0	268.0	59.1	512.7	141.5	214.1	139.2	139.2
Pickering Variance (days) (Actual - OEB/Appr.)	(35.9)	(227.3)	(92.3)	(13.4)	12.8	44.9	110.8	0.0	0.0	0.0	0.0	0.0
Pickering Variance (TWh) (Actual - OEB/Appr.)	(0.4)	(2.8)	(1.1)	(0.2)	0.2	0.56	1.4	0.0	0.0	0.0	0.0	0.0
Darlington Variance (days) (Actual - OEB/Appr.)	(148.9)	104.4	(27.9)	(112.2)	44.0	(245.1)	227.6	0.0	0.0	0.0	0.0	0.0
Darlington Variance (TWh) (Actual - OEB/Appr.)	(3.1)	2.2	(0.6)	(2.4)	0.9	(5.2)	4.8	0.0	0.0	0.0	0.0	0.0
Total Variance (TWh)	(3.6)	(0.6)	(1.7)	(2.5)	1.1	(4.6)	6.2	0.0	0.0	0.0	0.0	0.0
Revenue Rate ($/MWh) [9]	85.0	89.7	104.1	107.8	103.5	102.9	111.3	206.8	192.5	203.2	200.0	220.7
Revenue Deficiency ($M) [10, 12]	(289.9)	(52.7)	(173.5)	(262.4)	107.4	(450.2)	649.8	0.0	0.0	0.0	0.0	0.0

[1] OPG Budget, Ref. EB 2010-0008 E2-1-2 Table 1a, 1b

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

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

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

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

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

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

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

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

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

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

[12] Represents a notional revenue difference based on the difference in non-refurbishment planned outage days, before the impact of the Pickering B Variance Account and before any adjustments between OPG's submitted plans and OEB-approved values.

TAXES

1.0 PURPOSE

This evidence describes the basis for income taxes, commodity taxes and property taxes, and presents the regulatory income tax expense and the property tax expense for OPG's regulated hydroelectric facilities and nuclear facilities, and the Darlington New Nuclear Program ("DNNP") facilities. It also discusses the proposed federal Clean Electricity Investment Tax Credits ("CEITCs").

2.0 OVERVIEW

The forecast regulatory income tax expense and property tax expense for OPG's regulated hydroelectric facilities is $27.3M and $2.1M, respectively, for 2027, as presented in Ex. F4-2-1, Table 1. The forecast regulatory income tax expense are also presented for 2028-2031, as they underpin the calculation of the custom capital factor for the annual adjustment mechanism for the hydroelectric payment amounts under the proposed price-cap index Custom IR framework. These amounts are $70.3M for 2028, $87.6M for 2029, $101.6M for 2030, and $110.7M for 2031, as presented in Ex. F4-2-1, Table 3b.[1] The proposed Custom IR framework for the regulated hydroelectric facilities is described in Ex. A1-3-2.

As presented in Ex. F4-2-1, Table 2, the forecast regulatory income tax recovery for OPG's nuclear facilities is -$16.6M for each of the years from 2027 to 2031, while the forecast property tax expense is $14.0M for 2027, $14.2M for 2028, $14.5M for 2029, $14.8M for 2030, and $15.0M for 2031. As presented in F4-2-1, Table 2a, the forecast regulatory income tax expense for the DNNP facilities is $0.0M for each of the years from 2027-2031, and the forecast property tax expense is $0.0M for 2027 to 2029, $0.8M for 2030, and $3.7M for 2031. The regulatory tax loss carried forward to the next IR term is $1,808.8M for OPG's nuclear facilities and $575.1M for the DNNP facilities (attributable to taxable partners).

[1] Income taxes for the regulated hydroelectric facilities are included within the calculation of the incremental capital funding requirement used to derive the proposed C-factor on the basis that they are predominantly (though not entirely) capital-related.

For all income tax matters regarding OPG's prescribed facilities addressed in this exhibit, the same principles and methodology have been applied as in EB-2020-0290. Income tax expense and property tax expense included in the determination of Bruce Lease net revenues are discussed in Ex. G2-2-1.

As discussed in Ex. A1-4-4, DNNP LP is an Ontario limited partnership that was formed to facilitate investment in the DNNP. In September 2025, Canada Growth Fund, through its subsidiaries and Building Ontario Fund entered into equity commitment agreements, which upon contribution that are subject to satisfaction of certain conditions, will grant the parties minority ownership rights in DNNP LP. DNNP LP is expected to be a newly prescribed generator for the purposes of section 78.1 of the Act.[2]

For the purposes of calculating income taxes for the DNNP facilities, it is assumed that these assets will be transferred on December 31, 2025 and are presented separately beginning with the 2026 taxation year. Income taxes for OPG's prescribed facilities include the impacts of the DNNP facilities through 2024. Regulatory income taxes are calculated separately for DNNP LP beginning with the 2026 year.

Consistent with OPG's 2025-2031 Business Plan, the Application does not reflect potential impacts from the 2025 Federal Budget introduced on November 4, 2025. These impacts include the reissuance of draft legislation to provide a 15% refundable CEITC with respect to investments in certain clean electricity property and extending the accelerated investment incentive property ("AIIP") program that provides the ability to claim higher CCA deductions, among others.

If legislated, the revenue requirement impacts of the CEITCs on OPG's prescribed facilities would be captured in the proposed Clean Electricity ITC Variance Account (OPG), to the extent they are not captured in another existing account such as the Capacity Refurbishment

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[2] Pursuant to s.78.1 of the *Ontario Energy Board Act, 1998* and section 8 of O. Reg. 53/05, DNNP LP is expected to be prescribed subject to an order made by the OEB in which it specifies that certain conditions have been met. The Application expects these conditions to be met on December 31, 2025.

Variance Account ("CRVA") or the Nuclear Development Variance Account ("NDVA"). For the DNNP facilities, these impacts will be captured in the proposed Clean Electricity ITC Variance Account (DNNP), to the extent they are not captured in an existing account such as the Darlington New Nuclear Project Variance Account re Development ("DNNPVARD").

Revenue requirement impacts of extending the AIIP during the bridge years and IR term as it relates to OPG's prescribed facilities will continue to be captured in the Income & Other Taxes Variance Account (OPG), to the extent not captured in another existing account such as the CRVA or NDVA. For the DNNP facilities, these impacts during the IR term will be captured in the proposed Income & Other Taxes Variance Account (DNNP), to the extent not captured in an existing account such as the DNNPVARD. Refer to Ex. H1-1-1 for further discussion regarding these variance accounts. See Section 3.2.1 for further discussion on AIIP rules and Section 3.5 for further discussion on the CEITCs.

Beyond the discussion of the Federal Budget 2025, the layout of this evidence is largely unchanged from prior applications, with the exception of Section 3.2.9 that addresses the excessive interest and financing expenses limitation ("EIFEL") rules established by Bill C-59, the Fall Economic Statement Implementation Act, 2023 ("Bill C-59"), which can limit tax deductible interest expense for taxation years beginning on or after October 1, 2023.

Section 3.4 addresses the utilization of scientific research and experimental development ("SR&ED") investment tax credits ("ITCs") for the regulated hydroelectric business as of the effective date of the payment amounts order in this proceeding, as directed by the OEB.[3]

3.1 Calculation of Regulatory Income Tax Expense

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation ("OEFC") and to file federal and provincial

[3] In its Decision and Order in EB-2016-0152, the OEB stated that "OPG's next application should consider the utilization of SR&ED ITCs and explain its proposal" (p. 88). Since OPG did not file a hydroelectric payment amounts application in EB-2020-0290, details regarding the proposed treatment of the regulated hydroelectric SR&ED ITCs are provided in this proceeding.

income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

Under Canadian tax laws, partnerships such as DNNP LP do not pay income taxes; instead, each partner is required to include their share of the partnership taxable income or loss in their tax return. In this Application, regulatory income taxes for the DNNP facilities have been calculated, on a standalone basis, using the same income tax requirements that underpin the regulatory income taxes for OPG's prescribed facilities. Additionally, given that DNNP LP is a limited partnership, these regulatory income taxes have been calculated with respect to the tax status of the partners in DNNP LP, such that the regulatory income taxes reflect the portion of the regulatory taxable income that is attributable to taxable partners. Since tax-exempt partners are not required to pay income taxes, any portion of DNNP LP's regulatory taxable income attributable to such partners does not give rise to regulatory income taxes to be included in payment amounts. The subsidiaries of Canada Growth Fund and Building Ontario Fund that will hold minority interests in DNNP LP are presently tax-exempt and as such their share of regulatory taxable income does not give rise to regulatory income taxes. The Application proposes to establish the Impact of Change in Tax Status Variance Account (DNNP), discussed in Ex. H1-1-1, Section 8.7, to capture the impact on forecast regulatory income taxes reflected in the revenue requirement approved by the OEB of any changes to the tax status of current and future partners of DNNP LP.

The Application uses the taxes payable method for determining regulatory income taxes. Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement. Regulatory income taxes are determined by applying the statutory tax rates to the regulatory taxable income of the prescribed facilities and reducing the resulting amount by the recognized SR&ED ITCs.

Regulatory taxable income is computed by making additions and deductions to regulatory earnings before tax for items affected by differences in regulatory accounting treatment and tax treatment reflecting applicable requirements of the tax legislation. These additions and deductions are described in Section 3.2 below and are detailed in the calculation of annual regulatory income taxes for OPG's prescribed facilities at Ex. F4-2-1, Table 3 for 2020-2026, Ex. F4-2-1, Table 3b (regulated hydroelectric facilities) and Table 3d (OPG's nuclear facilities) for 2027-2031, and for the DNNP facilities at Ex. F4-2-1, Table 3g for 2026-2031.

Regulatory income taxes for OPG's prescribed facilities for the historical and bridge periods continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, and subtracting SR&ED ITCs. Total regulatory income taxes before SR&ED ITCs are then allocated based on each business' regulatory taxable income, with SR&ED ITCs predominantly directly attributed to each business based on the underlying expenditures giving rise to the ITCs.

For IR term ratemaking purposes, the standalone forecast annual regulatory income taxes for OPG's prescribed nuclear facilities and prescribed hydroelectric facilities are presented for the 2027-2031 period, and are determined by applying statutory tax rates to the forecast regulatory taxable income of such facilities, and subtracting any corresponding forecast SR&ED ITCs.[4] In a situation where a tax loss is forecast for an OPG regulated business in a given year of the IR term, the loss is applied (carried back or carried forward) to reduce such business' regulatory taxable income in other years of the IR term, as applicable, with any remaining tax losses carried forward to future IR terms. This approach is consistent with the cost allocation principle of direct assignment, whereby costs directly related to a business are directly assigned to that business, and was similarly applied in EB-2020-0290 and EB-2016-0152.[5] Forecast regulatory income taxes for OPG's regulated nuclear business presented for the IR term take into account the carryover of forecast tax losses for these facilities from the 2022-2026 IR term, determined using the above approach in the EB-2020-0290 Payment Amounts Order.[6]

[4] As in prior applications, the SR&ED ITCs reduce regulatory tax expense even when there is no income tax payable in a given year.
[5] See discussion in EB-2016-0152, Ex. A1-3-2, pp. 15-16 and Ex. L-11.2-1 Staff-253, and the OEB-approved settlement proposal, p. 15.
[6] EB-2020-0290, Payment Amounts Order, App. A, Table 22.

Similarly, for the DNNP facilities, the standalone forecast annual regulatory income taxes for the 2026-2031 period are determined by applying statutory tax rates to the portion of the forecast regulatory taxable income of these facilities attributable to the taxable partners of DNNP LP, and subtracting any corresponding forecast SR&ED ITCs attributable to such partners. In a situation where a tax loss is forecast for the DNNP facilities in a given year of the IR term, the portion of the loss attributable to the taxable partners is applied (carried back within the IR term or carried forward) to reduce the regulatory taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms. Tax losses attributed to non-taxable partners cannot be utilized and therefore cannot be carried forward.

There have been no changes in the statutory income tax rates in the historic period, and none are included in the forecast for the bridge or IR term. SR&ED ITCs are discussed in Section 3.5.

As discussed in Section 3.3, the income tax impacts associated with amounts recorded in deferral and variance accounts continue to be considered in the calculation of regulatory taxable income in the periods they are recovered from or refunded to ratepayers, rather than in the periods in which these amounts arise. Therefore, additions or deductions that reverse amounts reflected in regulatory earnings before tax are presented net of any corresponding additions recorded in deferral and variance accounts in the period, and any return on rate base recorded in deferral or variance accounts in the period is also reversed.[7]

Attachment 1 provides, as confidential material, OPG's most recent corporate income tax returns and the associated notices of assessment. The returns are for the 2024 taxation year, for the same companies included in EB-2020-0290. Exhibit F4-2-1, Table 4 presents the reconciliation of OPG's consolidated taxable income based on its 2024 tax returns to the calculation of regulatory taxable income for OPG's prescribed facilities for that year. Given that DNNP LP was formed in 2025, no tax returns have been filed to date.

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[7] The reversal of return on rate base amounts recorded in deferral and variance accounts continues to be presented as a separate adjustment to regulatory earnings before tax in the historical and bridge years at Ex. F4-2-1, Table 3, line 21. As no such deferral and variance account additions are forecasted for the purposes of determining regulatory earnings before tax in the IR term, the adjustment is not required for the 2027-2031 period.

3.2 Description of Additions and Deductions to Regulatory Earnings Before Tax

3.2.1 Depreciation and Amortization/Capital Cost Allowance ("CCA")

Accounting depreciation and amortization of fixed/intangible assets is not deductible for income tax purposes; however, CCA is deductible. Therefore, depreciation and amortization expense is an addition to regulatory earnings before tax, while CCA is deducted from regulatory earnings before tax. Accounting depreciation and amortization of fixed/intangible assets for OPG's prescribed facilities and the DNNP facilities are determined as described in Ex. F4-1-1.

The amount of depreciation/amortization expense added back to regulatory earnings before tax at Ex. F4-2-1, Table 3 for OPG's prescribed facilities is net of depreciation amounts for OPG's prescribed facilities recorded (or forecasted to be recorded) in the applicable years as net debit additions (or increased by such net credit additions) to the respective authorized deferral and variance accounts.

OPG's 2024 income tax returns provided in Attachment 1 include the calculations of CCA deductions by applying, by asset class, a prescribed rate to the Undepreciated Capital Cost ("UCC") balance (i.e., Schedule 8 of Ex. F4-2-1, Attachment 1). These schedules contain consolidated information for both OPG's regulated and unregulated assets. The UCC and CCA schedules for OPG's prescribed nuclear assets are provided in Ex. F4-2-1, Tables 21-27 for 2020-2026 and in Ex. F4-2-1, Tables 28-32 for 2027-2031 and reflect, up to and including 2024, any such amounts related to the DNNP facilities. The UCC and CCA schedules for OPG's prescribed hydroelectric assets are provided in Ex. F4-2-1, Tables 5-15 for 2016-2026 and in Tables 16-20 for 2027-2031.

The UCC and CCA schedules are provided for the DNNP facilities in Ex. F4-2-1, Tables 33-37 for 2027-2031. The forecasted UCC and CCA balances are nil prior to 2027, the year in which DNNP LP will first become eligible to claim CCA based on the "rolling start" and "long-term project" rules (discussed below). The UCC includes costs incurred by OPG and reimbursed by DNNP LP as part of the transfer of certain assets from OPG to DNNP LP (refer to Ex. A1-4-4, Section 2.0), and DNNP LP's subsequent expenditures toward the DNNP. As leasehold interests, DNNP LP's assets are subject to CCA Class 13 under existing tax legislation.

For projects that take longer than two years to put into service or complete, CCA can be calculated taking into account the "rolling start" rule, which allows CCA to be claimed on property acquired two years ago that has not been placed in service, and the "long-term project" rule that permits property acquired after the second year of a long-term project to become eligible for CCA deductions earlier than it otherwise would under the "rolling start" rule, subject to certain thresholds. These rules have been reflected in the forecast CCA amounts for the Darlington Refurbishment Program ("DRP"), Pickering Refurbishment Program ("PRP") and other material projects applicable to OPG's prescribed facilities, and the DNNP facilities.

The CCA amounts also reflect the ability to claim higher CCA deductions on AIIP[8] stemming from the passage of Bill C-97, the *Budget Implementation Act, 2019, No. 1*. The AIIP is property acquired after November 20, 2018, and put into service after that date.[9] Under the existing legislation, the ability to claim the higher CCA under these rules phases out by the end 2027. The AIIP rules under the existing legislation have been reflected in the forecast CCA amounts in the Application.[10]

In November 2025, the federal government introduced draft legislation proposing to reinstate the AIIP measures for qualifying property acquired on or after January 1, 2025, and that becomes available for use before 2034. As noted, the effect of these proposals is not reflected in OPG's 2025-2031 Business Plan or this Application and, if enacted, will be returned to ratepayers through one of the authorized deferral and variance accounts noted above.

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[8] The application of these rules includes property subject to the "rolling start" rule and "long-term project" election.

[9] Bill C-97 received Royal Assent on June 21, 2019. The changes generally resulted in a CCA allowance of three times the normal first-year CCA for assets acquired after November 20, 2018, and put into service before 2024 and two times the normal first-year CCA for assets acquired after November 20, 2018 and put into service during the 2024-2027 period.

[10] Until such time as the hydroelectric payment amounts are rebased, OPG continues to record the impact of the higher CCA deductions arising from the AIIP rules to its regulated hydroelectric facilities, in full, in the Income and Other Taxes Variance Account (OPG) or, for the applicable projects, in the CRVA. These accounts are discussed further in Ex. H1-1-1, Sections 5.5. and 5.6 respectively.

3.2.2 Nuclear Waste Management Variable Expenses

Consistent with the provisions of the *Income Tax Act* (Canada), accounting expenses accrued by OPG relating to its obligations for decommissioning its nuclear facilities and managing used nuclear fuel and low and intermediate level waste produced by these facilities (collectively, the "nuclear liabilities") are not deductible for tax purposes. Therefore, used fuel storage and disposal and low and intermediate level waste management variable expenses incurred in the period in relation to OPG's prescribed nuclear assets are added back to OPG's regulatory earnings before tax. These expenses are presented in Ex. C2-1-1, Table 2, lines 2 and 3. The amount added back to regulatory earnings before tax for these expenses in Ex. F4-2-1, Table 3 is net of amounts recorded (or forecasted to be recorded) in the applicable years as net debit additions (or increased by such net credit additions) to the respective authorized deferral and variance accounts.

3.2.3 Cash Expenditures for Nuclear Waste Management and Decommissioning

Cash expenditures incurred and charged against the nuclear liabilities for waste management and decommissioning activities are generally deductible for tax purposes in accordance with the regulations under the *Electricity Act*, *1998*. Such expenditures for OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 5.

The full amount of cash expenditures relating to OPG's prescribed nuclear facilities is presented at line 17 in Ex. F4-2-1, Table 3 for 2020-2026 and in Table 3d, line 16 for 2027-2031, as a deduction from OPG's regulatory earnings before tax. As part of Other additions presented at line 14 in Ex. F4-2-1, Table 3 for 2020-2026 and in Table 3d, line 13 for 2027-2031, and as noted in Section 3.2.8 below, a portion of these expenditures deemed to be capital for tax purposes is added back to OPG's regulatory earnings before tax in order to adjust the amount of cash expenditures deducted in arriving at OPG's regulatory taxable income. The CCA deduction discussed in Section 3.2.1 includes CCA related to these expenditures.

3.2.4 Segregated Fund Contributions and Receipts

The regulations under the *Electricity Act, 1998* allow OPG a tax deduction for contributions made to segregated funds pursuant to the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA contribution schedule based on the current approved ONFA Reference Plan is used to determine OPG's contributions to the segregated funds. The contribution amounts for OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 14 and are deducted from OPG's regulatory earnings before tax.

When OPG receives disbursements from the funds for reimbursement of eligible expenditures, the amounts received are taxable as per the regulations under the *Electricity Act, 1998*. The amounts related to OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 15 and are added to OPG's regulatory earnings before tax.

3.2.5 Pension and Other Post-Employment Benefits

Pension and other post-employment benefits ("OPEB") accrual costs recorded by OPG for accounting purposes (discussed in Ex. F4-3-2) are not deductible for tax purposes per the provisions of the *Income Tax Act* (Canada). Therefore, these costs are added back to OPG's regulatory earnings before tax. OPG's cash contributions to its registered pension plan as well as the payments for its OPEB and supplementary pension plans are deductible for tax purposes, and are reflected as deductions from OPG's regulatory earnings before tax.

The amount added back to OPG's regulatory earnings before tax for pension and OPEB accrual costs in Ex. F4-2-1, Table 3, line 5 is net of amounts recorded (or forecasted to be recorded) as net debit additions (or increased by such net credit additions) in the applicable years in the respective authorized deferral and variance accounts.[11] Pension and OPEB accrual costs are provided in Ex. F4-3-2, Chart 1 for OPG's regulated nuclear facilities and Ex. F4-3-2, Chart 2 for OPG's regulated hydroelectric facilities, and are added to OPG's earnings before tax. Pension and OPEB cash amounts are provided in Ex. F4-3-2, Chart 4 for OPG's

[11] As discussed in Ex. F4-3-2, the regulated hydroelectric revenue requirement proposed in the Application reflects pension and OPEB accrual costs and as of the effective date of the payment amounts order of this proceeding.

regulated nuclear facilities and Ex. F4-3-2, Chart 5 for OPG's regulated hydroelectric facilities are deducted from regulatory earnings before tax.

Once charged to DNNP LP by OPG, any pension and OPEB accruals become cash expenditures of DNNP LP by virtue of being payable to OPG under the respective service agreements between the parties. As such, the amount of pension and OPEB costs incurred by DNNP LP is expected to be deductible under the *Income Tax (Act)*. Pension and OPEB costs are provided in Ex. F4-3-2, Chart 3 for the DNNP facilities.

3.2.6 Adjustment Related to Financing Cost for Nuclear Liabilities

The calculation of OPG's regulatory earnings before tax adds back an adjustment in respect of the financing cost (i.e., return on rate base) for OPG's prescribed facilities' portion of the nuclear liabilities. This adjustment is required as a result of the methodology for the recovery of the revenue requirement impact of the nuclear liabilities (approved in EB-2007-0905 and applied in all subsequent payment amounts proceedings) and the inclusion of tax deductions for nuclear segregated fund contributions and cash expenditures on nuclear liabilities.

As part of the approved methodology discussed in Ex. C2-1-1, the revenue requirement treatment of the nuclear liabilities includes an amount derived by applying the weighted average accretion rate to the lesser of the average unfunded nuclear liabilities and the average unamortized asset retirement costs for the prescribed facilities. This amount is deducted in determining OPG's regulatory earnings before tax. For years 2020-2031, the derivation of this amount is presented in Ex. C1-1-1, Tables 1-12, line 7. The nuclear segregated fund contributions also include financing costs related to the nuclear liabilities and are also deducted in determining OPG's regulatory taxable income, as discussed in Section 3.2.4 above. Therefore, an adjustment is included as an addition to regulatory earnings before tax to remove an otherwise duplicate deduction between the return on rate base at the weighted average accretion rate and deductions for the nuclear segregated fund contributions and the cash expenditures on nuclear liabilities. The amount added to OPG's regulatory earnings before tax in Ex. F4-2-1, Table 3 is net of amounts recorded as net debit additions (or increased by such net credit additions) during applicable years in the respective authorized deferral and variance accounts.

3.2.7 Nuclear Fuel Expense Half-Charge Adjustment

Fifty percent of OPG's nuclear fuel expense (i.e., nuclear fuel bundle cost) incurred for its prescribed facilities in the year is not deductible for tax purposes until the following year. Accordingly, 50% of a given year's nuclear fuel expense is added to OPG's regulatory earnings before tax for the given year and 50% of the prior year's nuclear fuel expense is deducted from OPG's regulatory earnings before tax for the given year. The resulting adjustment is presented as a net addition or net deduction to OPG's regulatory earnings before tax at Ex. F4-2-1, Tables 3 and 3d. OPG's nuclear fuel bundle costs are provided at Ex. F2-5-1, Table 1a, line 3.

Once charged to DNNP LP by OPG in the form nuclear fuel service fees (discussed in Ex. F2-5-1, Section 5.0), nuclear fuel related costs become an operating expense of the DNNP LP and as such are expected to be deductible as incurred.

3.2.8 Other

This category includes other required additions or deductions to regulatory earnings before tax, such as:

- Nuclear materials and supplies obsolescence expenses recorded for accounting purposes as part of nuclear base OM&A costs (as noted in Ex. F2-2-1, Section 3.1) that are not deductible for tax purposes as per the *Income Tax Act* (Canada).
- Computer equipment expenditures that are expensed for accounting purposes but must be capitalized and are eligible for CCA deductions for tax purposes.
- Meals and entertainment expenses that are subject to the 50% tax deduction limitation.
- Adjustment to decrease the reduction for OPG's cash expenditures on nuclear waste management and decommissioning by the portion of such expenditures deemed to be capital for tax purposes, as discussed in Section 3.2.3.

3.2.9 Interest Deductibility Limits

On June 20, 2024, Bill C-59 received Royal Assent, which introduced the EIFEL rules under the *Income Tax Act* (Canada), effective for taxation years beginning on or after October 1, 2023. Under these rules, the tax-deductible amounts of net interest and financing expenses could be restricted in a given year.

Under EIFEL rules, the maximum net interest and financing expense deductible for tax purposes in a given year is limited to 30% of their adjusted taxable income, termed the base deduction capacity. The adjusted taxable income is computed, for regulatory purposes, by adding back to regulatory taxable income after loss carry-over the CCA and the net interest and financing expense for the year. If the net interest and financing expense for the year are above the base deduction capacity, the excess is restricted from being deducted in that year, subject to available excess capacity carried forward from prior years. If the net interest and financing expense for the year is below the base deduction capacity, the remaining deduction room represents excess capacity. Any excess capacity must first be utilized to deduct any net restricted interest and financing expenses carried forward. Any remaining unused excess capacity can be carried forward for three years to deduct net interest and financing expenses that would otherwise be restricted from being deducted due to the EIFEL rules.

Any restricted net interest and financing expense is added back to regulatory earnings before tax in the calculation of regulatory taxable income, as shown in Ex. F4-2-1, Table 3, line 10; Table 3b, line 6; Table 3d, line 10; Ex. F4-2-1, Table 3g, line 4. The application of the EIFEL rules does not result in restricted net interest and financing expense in this Application. The EIFEL calculations have been performed with reference to the deemed debt levels of the businesses.

The 2025 Federal Budget has reiterated the government’s intention to reintroduce an elective exemption for Canadian regulated energy utility businesses, first announced in the 2024 Fall Economic Statement, with respect to the EIFEL rules. Under this proposal, a Canadian regulated energy utility business would be able elect to exclude the interest and financing expenses incurred on arm’s length debt for the purposes of the EIFEL rules and the income from the regulated energy utility business would also be excluded from the adjusted taxable income. The election would effectively result in the EIFEL restrictions not applying to interest incurred on borrowings used to finance the Canadian regulated utility business. Although they produced no restricted interest expense, the EIFEL calculations for the purposes of this application did not include the impact of making such an election.

3.3 Regulatory Tax Treatment of Deferral and Variance Account Recovery

Amounts recorded in deferral and variance accounts in a given period, which are reported as regulatory assets or liabilities for accounting purposes, typically impact actual taxable income in a different period. As a result, amounts recognized for accounting purposes as regulatory assets or liabilities in the period are reversed from regulatory earnings before tax in determining actual taxable income (e.g., Ex. F4-2-1, Table 4, col. (a), lines 19-22). It is noted that while the discussion below is presented with respect to OPG's prescribed facilities, it is expected that similar considerations will be applied to the DNNP facilities in subsequent proceedings, once DNNP LP begins recording and disposing of amounts in its deferral and variance accounts.

For regulatory purposes, as in prior OPG payments amounts proceedings, the tax impact (i.e., tax benefits or costs) to be recovered from, or provided to, ratepayers of the amounts recorded in deferral and variance accounts is reflected in the calculation of regulatory taxable income over the same period as these amounts are recovered from, or refunded to, ratepayers. This approach is intended to result in the same total tax impact as the actual tax payable in respect of recovery or refund of the amounts, considering the entire period from when the variance or deferral account balance is initially recorded to when the balance is fully recovered or refunded. This regulatory treatment provides for a matching of costs and benefits in accordance with the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

In calculating earnings, the balance of the deferral and variance accounts recovered or refunded through payment amounts in the period is reflected in both the regulated revenues and the amortization expense (or amortization credit) for that period. Amortization is not deductible for income tax purposes. Since the amounts of revenue and amortization typically would be equal and offsetting, there is no net impact on regulatory earnings before tax for the period. In calculating regulatory income taxes, no adjustment to regulatory earnings before tax is made for the amortization, subject to the discussion below, because the amount that would otherwise be added back to, or deducted from, such earnings before tax as amortization expense/credit is the same as the amount that would be deducted from, or added back to, the earnings before tax in order to attribute the associated benefit or cost to ratepayers.

To the extent that there is no tax benefit/cost to be matched to the variance or deferral account recovery or refund, there is a net income tax impact associated with the amounts recorded in these accounts. In instances where this impact is not otherwise reflected in the account balance itself, an adjustment to regulatory earnings before tax is required in the period of recovery.

The Nuclear Liability Deferral Account, the CRVA, the Pension and OPEB Cost Variance Account, the NDVA and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account are the principal accounts of OPG that currently record amounts for the prescribed facilities that do not have a matching tax benefit.[12] These accounts reflect the associated income tax impacts as part of amounts recorded in the account, and therefore no adjustment to earnings before tax is required in respect of the recovery of these balances. With respect to the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the associated income tax impacts are not recorded in the account. As addressed in EB-2018-0243, and continued in EB-2020-0290, EB-2023-0336 and this Application, these impacts are being recovered through the appliable deferral and variance account riders (see Ex. H1-2-1).

An adjustment to regulatory earnings before tax continues to be required to address the impact of the regulatory treatment of the Bruce Lease net revenues on the disposition of the Bruce Lease Net Revenues Variance Account. The forecast net revenues from the Bruce Lease are applied against OPG's nuclear revenue requirement and therefore the earnings before tax for OPG's prescribed facilities, as shown in Ex. F4-2-1, Table 3f, Note 1. To the extent that there is a difference between the forecast and actual net revenues from the Bruce Lease (i.e., an entry into the Bruce Lease Net Revenues Variance Account), there is a difference in the regulatory earnings before tax and therefore the income taxes for OPG's prescribed facilities. Hence, an adjustment to regulatory earnings before tax is required in the year of

[12] Components of the Income & Other Taxes Variance Account (OPG) also reflect the associated income tax impacts (i.e., gross-up) as part of the amounts recorded therein. Given the modest balances being sought for disposition in this proceeding, an adjustment to regulatory earnings before tax continues to be shown in Ex. F4-2-1, Table 3, line 8 for the combined prescribed facilities, and in Table 3b, line 5 and Table 3d, line 8 for the regulated hydroelectric and nuclear facilities, respectively, for the full balance of the account. Going forward, OPG will seek to ensure that all components of the account consistently reflect the income tax impacts, eliminating the need for this adjustment to earnings before tax.

recovery/refund of the variance recorded in the Bruce Lease Net Revenues Variance Account to ensure that any over-collection of, or shortfall in, regulatory taxes is also refunded to, or recovered from, ratepayers. Accordingly, the amortization of the Bruce Lease Net Revenues Variance Account is added back to OPG's regulatory earnings before tax, as shown in Ex. F4-2-1, Tables 3 and 3d, line 6. In addition to historical and bridge years, this adjustment is included for years 2027 to 2029 to reflect amortization amounts for the Bruce Lease Net Revenues Variance Account proposed in this Application (see Ex. H1-2-1).

3.4 SR&ED Investment Tax Credits

OPG and DNNP LP can claim non-refundable federal ITCs equal to 15% and an Ontario ITC of 3.5% (4.5% prior to June 1, 2016) of the qualifying SR&ED expenditures incurred in the year. OPG files annual ITC claims based on qualifying expenditures identified; DNNP LP is expected to do the same. The federal ITCs reduce the federal portion of corporate income taxes (or payments in lieu thereof) otherwise payable and are taxable in the subsequent year. The Ontario ITCs reduce the Ontario portion of corporate income taxes (or payments in lieu thereof) otherwise payable and are taxable in the year earned. Additionally, certain expenditures that are capitalized for accounting purposes are deductible for income tax purposes as SR&ED qualifying expenditures in the year incurred (and are also eligible for SR&ED ITCs). These expenditures are deducted from regulatory earnings before tax in computing regulatory taxable income, as shown in Ex. F4-2-1, Table 3, line 22; Table 3b, line 14; Table 3d, line 21; and Table 3g, line 12.

In November 2025, the federal government introduced draft legislation to allow the expensing of capital expenditures other than land or a leasehold interest in land and incurred with respect to SR&ED activities, made after December 16, 2024. The impact of this proposal has not been reflected in this Application as the legislation has not been adopted yet, and it is also not reflected in OPG's 2025-2031 Business Plan. The tax deduction benefit of these changes, once implemented, will be credited to the Income and Other Taxes Variance Account (OPG) for OPG's prescribed facilities and, as proposed in Ex. H1-1-1, the Income and Other Taxes Variance Account (DNNP) for the DNNP facilities, unless it is subject to another deferral or variance account such as the CRVA or the DNNPVARD. The SR&ED ITCs would be credited to the SR&ED ITC Variance Account (OPG) for OPG's prescribed facilities and, as proposed in Ex. H1-1-1, the SR&ED ITC Variance Account (DNNP) for the DNNP facilities.

As in prior payment amounts applications, the amount of SR&ED ITCs recognized by OPG for accounting purposes is determined based on an assessment of the likelihood of their allowance, in accordance with generally accepted accounting principles ("GAAP"). Under US GAAP, the amount of SR&ED ITCs recognized in the period is recorded as a reduction to income tax expense for that period. This reduction to income tax expense from 2022-2026 for OPG's prescribed facilities is presented at Ex. F4-2-1, Table 3, line 30; Ex. F4-2-1, Table 3b, line 22; Table 3d, line 29. As of the effective date of the payment amounts order in this proceeding, the Application proposes adopting the same treatment for any SR&ED ITCs that recognized by DNNP LP. The reduction to income tax expense for the DNNP facilities is presented at Ex. F4-2-1, Table 3g, line 21. Consistent with the 2025-2031 Business Plan and the approach in EB-2020-0290, forecast SR&ED ITCs for OPG's prescribed facilities are based on the actual amounts claimed for the most recent completed taxation year, being 2024, excluding amounts related to the DNNP facilities.

In determining actual and forecast income tax expense for its regulated nuclear business and hydroelectric businesses, OPG continues to recognize 75% of the SR&ED ITCs for taxation years that are subject to audit. For years the audit of which has been resolved, the previously recognized amounts are adjusted, as necessary, to reflect the audit resolution. Until May 31, 2017, to the extent the ultimate percentage of recognition for SR&ED ITCs differed from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG recorded the difference in the SR&ED ITCs, including the tax on the difference, in the Income and Other Taxes Variance Account for both its prescribed nuclear and regulated hydroelectric facilities. This treatment remains in place for the regulated hydroelectric facilities. As directed by the OEB in EB-2016-0152 and subsequently continued in EB-2020-0290, starting June 1, 2017, any difference between the forecast SR&ED ITCs reflected in approved payment amounts for OPG's prescribed nuclear facilities and such actual SR&ED ITCs as determined after any tax audits, including the tax on the difference, is recorded in the SR&ED

ITC Variance Account (OPG). Refer to Ex. H1-1-1, Section 5.20 for further discussion of the account.

In its Decision and Order in EB-2016-0152, the OEB instructed OPG to consider the utilization of SR&ED ITCs for its regulated nuclear and hydroelectric businesses in its next application.[13] The treatment of SR&ED ITCs described above was reflected in the OEB-approved settlement proposal in EB-2020-0290 for OPG's nuclear facilities. It remains reasonable for the IR term as the circumstances observed at the time of EB-2016-0152 and continued in EB-2020-0290 related to the inherent difficulty in forecasting such ITCs have not substantially changed, particularly as OPG moves through the execution of the PRP. The PRP will contain certain scopes of work not previously performed as part of the DRP (see Ex. D2-3-5). OPG proposed no change to the treatment of the SR&ED ITCs for the regulated hydroelectric business in EB-2020-0290 as the hydroelectric base payment amounts were not then rebased and instead were set by O. Reg 53/05. For this IR term, the Application proposes that the same treatment be adopted for the SR&ED ITCs for OPG's regulated hydroelectric facilities as for its nuclear facilities, including the operation of the SR&ED ITC Variance Account (OPG). In addition to the benefits of consistency, this is reasonable due to the inherently greater difficulty in forecasting such ITCs as a result of the increased capital program for the hydroelectric facilities going forward.

The Application does not reflect any forecast SR&ED ITCs for the DNNP facilities during the bridge year or the IR term because this project is unique and not similar to any other project undertaken by OPG given that it is the first of its kind. As such there is significant uncertainty associated with the potential SR&ED eligibility of projects. The Application proposes to address this uncertainty by establishing the SR&ED ITC Variance Account (DNNP), to record such actual SR&ED ITCs, net of tax thereon, on the same basis as the SR&ED ITC Variance Account (OPG). Refer to Ex. H1-1-1, section 8.3 for further discussion of the proposed account.

[13] EB-2016-0152, Decision and Order, December 28, 2017, p. 88.

3.5 Clean Electricity ITC

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects. The proposed CEITC would be available to income tax exempt entities such as OPG. As a limited partnership, for DNNP LP, CEITC eligibility would be determined based on whether the respective partner is eligible to receive the CEITC. To be entitled to the full 15% CEITC, an entity would be required to meet certain prevailing wage and apprenticeship requirements. The federal government reissued draft legislation to institute the CEITC in November 2025. At the time of filing the Application, this legislation has not yet been adopted. The CEITCs are not reflected in OPG's 2025-2031 Business Plan or the proposed revenue requirements in this Application. Pursuant to income tax legislation, the CEITC will reduce the UCC pool, resulting in a reduction of the annual CCA available to OPG and DNNP LP to shelter taxable income in the future.

The CEITCs are expected to be recorded for eligible projects when they are received. The CEITC would reduce the cost of the related asset as required under US GAAP. US GAAP also requires that a reserve be recorded for amounts that may not be realized. The reserve would be released upon the completion of the audit for the relevant taxation year.

To ensure the benefit of the CEITCs is realized by ratepayers (if the CEITC is legislated), the Application proposes to record the revenue requirement impacts in two newly proposed variance accounts:

1) Clean Electricity ITC Variance Account (OPG) – As discussed in Ex. H1-1-1, Section 7.3, this account is proposed to record the revenue requirement impact of CEITCs received for eligible investments in OPG's prescribed facilities to the extent it is not captured in existing accounts.

2) Clean Electricity ITC Variance Account (DNNP) – As discussed in Ex. H1-1-1, Section 8.6, this account is proposed to record the revenue requirement impact of CEITCs received for eligible investments in the DNNP facilities to the extent it is not captured in existing accounts.

For OPG's CRVA eligible projects including the PRP and major hydroelectric turbine-generator refurbishments, the revenue requirement impacts of the CEITCs will be captured in the CRVA. For the DNNP, these impacts will be captured in DNNPVARD.

The revenue requirement impact of CEITCs will be realized through a reduction in the capital related revenue requirement. Specifically, the recognized CEITCs will reduce in-service rate base, associated depreciation expense and cost of capital amounts and the attendant tax effects, while reducing the available CCA deductions as discussed above.

Additionally, the CEITCs are expected to reduce the amount of PRP and DNNP capital expenditures for which recovery of interest is provided prior to such assets being placed in service pursuant to O. Reg. 53/05. These amounts are subject to and, as necessary, will be reconciled through the Pickering B Refurbishment Project Variance Account (for the PRP) and Darlington New Nuclear Project Variance Account re Capital Cost Amounts (for the DNNP). These accounts are discussed in Ex. I1-1-3.

4.0 INCOME TAX EXPENSE TREND

The actual (2020-2024) and forecast (2025 and 2026) annual regulatory income tax expense for OPG's prescribed facilities, the forecast income tax expense (2027-2031) for the regulated hydroelectric facilities and the forecast income tax expense (2027-2031) for OPG's nuclear facilities has been computed using the approach described in Section 3. The 2020-2026 regulatory income tax expense calculations are shown in Ex. F4-2-1, Table 3. The 2027-2031 regulatory income tax expense calculations for the regulated hydroelectric facilities is shown in Ex. F4-2-1, Table 3b and the 2027-2031 regulatory income tax expense calculations for OPG's nuclear facilities are shown in Ex. F4-2-1, Table 3d. The income taxes for the regulated hydroelectric facilities for the 2016-2026 period are presented in Ex. F4-2-1 Table 1; for the nuclear facilities, income taxes for the 2020-2026 period are shown in Ex. F4-2-1, Table 2.

The forecast tax expense for the regulated hydroelectric facilities over the forecast period is $27.3M in 2027, $70.3M in 2028, $87.6M in 2029, $101.6M in 2030 and $110.7M in 2031. There were no carryover tax losses from prior periods attributed to the regulated hydroelectric facilities and no tax losses are projected for these facilities. The increase in regulatory income taxes over the forecast period reflects the growth in regulatory earnings before tax commensurate with the increase in the rate base, and some variability in CCA deductions.

The forecast tax expense for the nuclear facilities in the IR term is -$16.6M in 2027, -$16.6M in 2028, -$16.6M in 2029, -$16.6M in 2030 and -$16.6M in 2031. The negative tax expense for 2027-2031 represents the forecast amount of SR&ED ITCs attributed to the nuclear facilities in those years and reflects the impact of the carryover of EB-2020-0290 forecast nuclear regulatory tax losses of $373.4M at the end of 2026[14] and projected nuclear regulatory tax losses of $20.6M, $111.5M, $504.5M, $634.2M, and $164.6M arising in 2027, 2028, 2029, 2030, and 2031, respectively. The nuclear regulatory tax loss balance at the end of 2031 of $1,808.8M would be carried forward to the next rate-setting period. The regulatory tax loss carry-forward schedule for the nuclear facilities is presented at Ex. F4-2-1, Table 3e.

The forecasted income tax expense for the DNNP facilities during the IR term is nil each year. This is because regulatory tax losses are forecasted for years 2027 to 2030 due to a combination of nil or low regulatory earnings before tax, combined with CCA deductions. Although taxable income is forecasted in 2031, it is entirely offset by regulatory tax losses carried forward from the earlier years. For the reasons discussed in Section 3.4, no SR&ED ITCs have been forecasted for the DNNP facilities.

Over the historical period, the regulatory income taxes for OPG's prescribed facilities fluctuate mainly with the variability in regulatory earnings before tax and also reflect a trend of increasing CCA deductions, driven by OPG's expanding capital program.

[14] EB-2020-0290, Payment Amounts Order, App. A, Table 22.

5.0 COMMODITY TAX

Pursuant to the *Excise Tax Act* (Canada), OPG is subject to the 13% Harmonized Sales Tax ("HST") on almost all of its purchases of goods and services. The recoverable portion of HST paid by OPG is claimed as input tax credits on returns filed monthly. The recoverable portion of HST forecast to be paid is therefore not included in the revenue requirement. As in prior payment amounts applications, the impact of HST is incorporated into the computation of the cash working capital component of rate base presented in Ex. B1-1-2. DNNP LP is similarly subject to the HST.

Where applicable, OPG continues to pay duty under the *Customs Act* (Canada) on goods imported into Canada. Some of these imports continue to be either exempt or have duty free status through the United States–Mexico–Canada Agreement. For supply and installation contracts, the contractor's price includes duty, if applicable, on the goods imported to perform the work. Any duty paid forms part of the cost of the underlying item.

6.0 PROPERTY TAX EXPENSE

The nature, basis, and components of OPG's property tax expenses are unchanged from the evidence presented in prior payment amounts applications.

For OPG's hydroelectric portfolio, conventional municipal property taxes are payable on certain assets (e.g. workshops, service centers, etc.) which support hydroelectric facilities. Tax information on these facilities is presented by region in Ex. F4-2-1, Table 1. These property taxes are paid at Current Value Assessment and are typically forecasted to increase by approximately $0.1M to $0.2M annually.

OPG's nuclear portfolio remains responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the OEFC. The total of these two payments is intended to represent what a commercial generating company would pay as property tax, based on full Current Value Assessment ("CVA"), and represents OPG's property tax expense. OPG's property tax expense for the regulated nuclear facilities is presented in Ex. F4-2-1, Table 2, for the historical, bridge periods, and IR term years. The property tax expense for the regulated nuclear facilities gradually increases over the bridge period and IR term, reflecting differences in municipal property tax rates and changes in property assessment values.

Property tax for DNNP facilities is discussed in Section 6.3 below.

Municipal property taxes paid by OPG for properties that are not directly associated with specific generation business units and are held centrally, are part of the asset service fees as discussed in Ex. F3-2-1. Property taxes associated with the Bruce assets are presented separately in Ex. G2-2-1.

6.1 Municipal Property Taxes

Municipal property taxes are regulated under the *Assessment Act, R.S.O. 1990* (the "Act"). For prescribed nuclear and Bruce assets, property tax payments to municipalities continue to be paid based on a statutory assessment rate of $86.11 per square meter for most of the ground floor area of "generating" buildings (e.g., buildings that are used in, or auxiliary to, the generating process, such as a powerhouse, water treatment plant, pump houses, etc.) pursuant to the Act, and at CVA for "non-generating" buildings (e.g., administration/office buildings). For both "generating" and "non-generating" buildings, the Municipal Property Assessment Corporation issues notices of assessments annually and the local municipality levies a local tax rate against the assessed value of the property. Additionally, for "generating" buildings, OPG continues to be subject to payment in lieu of property tax discussed below.

For hydroelectric assets, OPG continues to pay municipal property tax under the Act only for properties that are not associated with a generating station or dam site. These property taxes are paid at CVA. For 2027, a $1.0M annual increase reflects the anticipated construction of a new facility required to support Western Region Operations.

6.2 Payment in Lieu of Property Tax

Payment in lieu of property tax is regulated through O. Reg. 423/11 (previously O. Reg 224/00) under the *Electricity Act, 1998* and is paid to the OEFC. The payment in lieu of property tax represents taxes based on the difference between CVA and the prescribed municipal assessment rate of $86.11 per square meter for most of the ground floor area of certain generating assets.

As noted in prior applications, the assessment basis under O. Reg. 423/11 has not been updated since 1999. Consequently, the CVA used for payment in lieu of property tax calculations and the payments in lieu of tax amounts themselves remain subject to a possible update. Property tax expense forecasts for all years presented in this application assume that the assessed values set out in O. Reg. 423/11 will not be updated within the reporting period. Changes in property taxes resulting from a change in O. Reg. 423/11 would be recorded in the Income and Other Taxes Variance Account (OPG), as per the OEB-approved scope of the account.

6.3 Darlington New Nuclear Program

The small modular reactors to be built as part of the DNNP will be sited on existing OPG land holdings adjacent to Darlington. There are three components to the property tax payable to consider for a property of this type, including: application of the statutory rate, calculation of the payments in lieu of property tax, and application of CVA to those property components not eligible for the statutory rate. Given that this technology includes a facility layout that is markedly different from other nuclear facilities in Ontario, the assessment of property taxes is currently uncertain. For the purposes of estimating the property-based taxes payable for the DNNP facilities, the following assumptions have been made.

First, it is assumed that the reactor buildings are the only building components that will be eligible for the statutory rate. On this basis, calculation of the municipal tax payable on the reactor buildings is estimated based on the statutory rate, applied to the gross first floor area, plus any payments in lieu (“PIL”) of property tax payable. In terms of calculating the PIL, the PIL property tax payable at the Bruce site has been used as a proxy to determine the assessment rate for the DNNP as it is the most recent market example available. This proxy is applied to the estimated gross floor area of the reactor buildings, together with the local tax rate in Clarington, to estimate the PIL payable. The property tax payable for all other buildings is limited to municipal property tax only, which has been estimated on the CVA basis.

The Application proposes to record the impact of changes in property-based taxes payable on the DNNP resulting from an update to the statutory assessment rates as noted in 6.2 above in the proposed Income and Other Taxes Variance Account (DNNP), as discussed further in Ex. H1-1-1, Section 8.4.

LIST OF ATTACHMENTS

Attachment 1: Income Tax Returns and associated Notices of Assessment for 2024 (filed entirely in confidence)

Includes:

Part 1 – T2 Corporation Income Tax Return Ontario Power Generation Inc.

Part 2 – T2 Corporation Income Tax Return OPG – Huron A Inc.

Part 3 – T2 Corporation Income Tax Return OPG – Huron B Inc.

Part 4 – T2 Corporation Income Tax Return OPG – Huron Common Facilities Inc.

Part 5 – Notices of Assessment – Hydro Payment in Lieu

Numbers may not add due to rounding.

Table 3g
Calculation of Regulatory Income Taxes - DNNP Facilities ($M)
Years Ending December 31, 2026-2031

Line No.	Particulars	Note	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Regulatory Taxable Income							
1	**Regulatory Earnings Before Tax**	1	0.0	0.0	0.0	0.2	124.9	594.9
	Additions for Regulatory Tax Purposes:							
2	**Depreciation and Amortization**		0.0	0.0	0.0	0.0	22.6	109.7
3	**Pension and OPEB Accrual**	4	10.0	14.1	13.3	11.9	10.1	9.5
4	**Restricted Net Interest and Financing Expense**		0.0	0.0	0.0	0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0	0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0	0.0	0.0	0.0
7	**Total Additions**		10.0	14.1	13.3	11.9	32.7	119.2
	Deductions for Regulatory Tax Purposes:							
8	**CCA**	2	0.0	195.5	311.1	345.0	365.6	377.3
9	**Pension Plan Contributions**	4	0.6	1.4	0.3	0.4	0.2	0.3
10	**OPEB Payments**	4	9.4	12.7	13.0	11.5	9.9	9.2
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0	0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0	0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Deductions**		10.0	209.6	324.4	356.9	375.7	386.8
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		0.0	(195.5)	(311.1)	(344.8)	(218.1)	327.3
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5	0.0	44.0	70.0	77.6	49.1	(73.7)
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5	0.0	151.5	241.1	267.2	169.0	(253.7)
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	3	0.0	0.0	0.0	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 18 x line 24)		0.0	0.0	0.0	0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 18 x line 25)		0.0	0.0	0.0	0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0	0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-Controlling Partners** (line 21 x 22.5%)		0.0	0.0	0.0	0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0	0.0	0.0	0.0
	Income Tax Rate:							
24	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
26	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3i.

Numbers may not add due to rounding.

Table 3i
Notes to Table 3g
Calculation of Regulatory Income Taxes ($M)
Years Ending December 31, 2027-2031

Notes:
1 Regulatory Earnings Before Tax for the Darlington New Nuclear Program from 2027 - 2031 are calculated as follows :

Line No.	Item	Reference	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Darlington New Nuclear Program	Ex. I1-1-1, Table 2a, line 11	0.0	0.0	0.2	124.9	594.9
2a	Additions for Regulatory Tax Purposes	line 7	14.1	13.3	11.9	32.7	119.2
3a	Deductions for Regulatory Tax Purposes	line 14	209.6	324.4	356.9	375.7	386.8
4a		line 1a + line 2a - line 3a	(195.5)	(311.1)	(344.8)	(218.1)	327.3
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(29.3)	(46.7)	(51.7)	(32.7)	49.1
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(19.5)	(31.1)	(34.5)	(21.8)	32.7
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(48.9)	(77.8)	(86.2)	(54.5)	81.8
9a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	29.3	46.7	51.7	32.7	(49.1)
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	19.5	31.1	34.5	21.8	(32.7)
11a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	48.9	77.8	86.2	54.5	(81.8)
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.0	0.0	0.2	124.9	594.9
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.0	0.0	0.2	124.9	594.9

2 Amounts are from Ex. F4-2-1, Tables 33-37, col. (j) - (i).
3 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the DNNP's taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms.
4 The DNNP facilities will pay OPG its attributed portion of OPG's pension and OPEB accrual costs under the respective agreements. As a result, its pension plan contributions and OPEB payments are equivalent to its pension and OPEB accrual.
5 DNNP LP is a limited partnership in which tax-exempt investors are expected to hold a stake of 22.5% and therefore, the DNNP facilities' revenue requirement only reflects the impact of the remaining 77.5% of the tax loss or income.

FTE, Compensation and Benefit Information for OPG's Nuclear Darlington Facilities ("Appendix 2k")

Numbers may not add due to rounding — EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Darlington NGS[4]	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**
	Darlington - Direct												
1	Executive	12.5	10.6	10.8	12.0	14.0	14.2	13.2	13.3	13.0	12.8	12.1	11.9
2	Non-Executive Management	218.8	192.8	182.2	208.6	245.2	279.4	263.3	279.9	271.9	257.6	251.3	245.6
3	Management Subtotal	231.4	203.4	193.0	220.5	259.2	293.7	276.5	293.3	284.9	270.4	263.5	257.5
4	Society	841.9	872.5	802.4	822.9	896.1	1,074.4	1,079.7	1,055.5	1,012.8	965.1	949.7	942.1
5	PWU	1,376.6	1,488.0	1,212.6	1,114.2	1,187.4	1,489.6	1,554.8	1,580.7	1,551.2	1,585.7	1,544.2	1,544.4
6	Term/ETE/PECO Temp	33.5	85.8	153.2	240.6	220.9	89.0	117.0	-	-	-	-	-
7	EPSCA	76.4	105.3	125.3	111.4	118.1	87.8	50.2	35.0	30.0	20.0	19.9	19.9
8	Subtotal	2,559.8	2,755.1	2,486.6	2,509.7	2,681.7	3,034.4	3,078.1	2,964.4	2,878.9	2,841.1	2,777.3	2,763.9
	Darlington - Allocated												
9	Executive	10.6	11.4	12.2	11.7	11.1	13.1	11.5	10.8	9.8	9.5	8.5	8.6
10	Non-Executive Management	119.1	121.2	123.7	136.1	145.2	173.4	146.3	133.5	127.1	125.0	119.2	120.9
11	Management Subtotal	129.7	132.6	135.9	147.8	156.3	186.5	157.9	144.3	136.9	134.5	127.7	129.5
12	Society	203.3	189.2	200.5	259.8	282.6	323.6	275.0	283.6	276.1	272.8	267.8	262.8
13	PWU	211.0	196.1	212.0	231.2	215.3	216.5	193.0	208.7	205.0	206.0	209.2	216.5
14	Term/ETE/PECO Temp	11.5	23.3	26.7	24.3	25.6	19.5	17.4	-	-	-	-	-
15	EPSCA	9.6	10.8	8.9	9.7	7.5	17.3	13.9	13.2	13.2	13.2	13.2	17.2
16	Subtotal	565.0	552.0	584.0	672.9	687.3	763.4	657.2	649.8	631.2	626.6	617.9	626.0
	Darlington GS Facilities												
17	Executive	23.1	22.0	23.0	23.7	25.1	27.4	24.7	24.1	22.8	22.3	20.6	20.5
18	Non-Executive Management	338.0	314.0	305.9	344.7	390.3	452.8	409.6	413.4	399.0	382.6	370.5	366.5
19	Management Subtotal	361.1	336.0	328.9	368.4	415.4	480.1	434.3	437.5	421.7	404.9	391.1	387.0
20	Society	1,045.1	1,061.6	1,003.0	1,082.8	1,178.7	1,398.0	1,354.7	1,339.1	1,288.9	1,238.0	1,217.5	1,204.9
21	PWU	1,587.6	1,684.1	1,424.6	1,345.4	1,402.7	1,706.1	1,747.8	1,789.4	1,756.2	1,791.7	1,753.5	1,760.9
22	Term/ETE/PECO Temp	45.0	109.1	179.9	264.9	246.5	108.5	134.4	-	-	-	-	-
23	EPSCA	86.0	116.1	134.2	121.1	125.6	105.0	64.2	48.2	43.2	33.2	33.2	37.1
24	Total	3,124.8	3,307.0	3,070.6	3,182.5	3,369.0	3,797.8	3,735.3	3,614.2	3,510.1	3,467.8	3,395.2	3,389.8
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	6.3	6.5	6.2	6.0	6.6	7.1	6.5	6.4	6.2	6.2	5.8	5.9
26	Non-Executive Management	50.9	45.5	48.3	51.6	61.0	73.0	68.7	72.6	71.7	71.4	70.7	71.8
27	Management Subtotal	57.2	52.0	54.6	57.6	67.6	80.1	75.2	79.0	77.8	77.6	76.5	77.7
28	Society	139.5	149.1	137.6	173.6	182.7	220.5	217.4	225.1	223.1	224.4	227.0	233.2
29	PWU	184.1	208.2	166.5	194.8	229.8	224.0	235.7	254.7	257.5	276.7	276.7	287.2
30	Term/ETE/PECO Temp	4.8	9.9	22.2	34.1	29.5	12.6	16.0					
31	EPSCA	12.4	16.0	16.4	15.9	19.1	16.5	11.1	8.6	7.9	6.3	6.3	7.2
32	Unallocated[3]	3.1											
33	Total	401.0	435.3	397.3	476.0	528.7	553.8	555.3	567.5	566.3	584.9	586.5	605.3
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	3.8	3.4	3.6	4.2	3.1	3.9	3.0	3.1	3.2	3.2	3.1	3.2
35	Non-Executive Management	11.2	11.5	10.9	15.5	14.8	16.1	11.5	12.0	12.5	12.5	12.3	12.3
36	Management Subtotal	15.0	14.9	14.5	19.7	18.0	20.1	14.5	15.1	15.6	15.6	15.4	15.5
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society (Regular)	2.1	2.1	2.4	2.4	2.7	1.5	1.2	1.2	1.2	0.9	0.9	0.7
38	PWU (Regular)	4.9	5.3	5.7	6.1	6.1	3.8	3.2	3.2	3.1	2.7	2.4	0.5
39	Total	7.0	7.3	8.1	8.5	8.8	5.3	4.4	4.4	4.2	3.6	3.3	1.3
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	15.5	21.2	17.7	17.3	21.5	17.0	16.8	20.8	17.7	20.6	19.3	19.1
41	PWU	29.9	39.1	28.5	28.4	35.8	29.9	33.2	45.5	35.4	46.0	39.4	40.7
42	Term/ETE/PECO Temp	0.5	1.3	2.9	4.5	3.6							
43	EPSCA	1.3	2.8	4.7	4.8	6.0	1.3	1.9	1.3	1.0	0.5	0.5	0.5
44	Unallocated[3]												
45	Total	47.2	64.5	53.7	55.0	67.0	48.2	51.9	67.6	54.1	67.2	59.2	60.3
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	3.3	3.6	3.4	2.1	2.5	2.6	2.5	2.5	2.4	2.4	2.2	2.2
47	Non-Executive Management	24.7	26.9	26.0	13.0	23.4	25.7	26.4	27.7	27.3	27.4	26.9	27.5
48	Management Subtotal	28.0	30.5	29.5	15.1	25.9	28.2	28.9	30.1	29.6	29.8	29.1	29.7
49	Society	67.7	81.9	74.9	35.9	68.6	77.9	85.1	86.5	85.8	87.3	88.2	91.3
50	PWU	81.4	99.0	83.0	38.0	73.9	76.5	85.2	93.1	93.7	99.8	101.8	106.4
51	Term/ETE/PECO Temp	0.3	0.3	1.6	2.1	2.6	0.7	0.9					
52	EPSCA	0.8	0.7	0.6	0.0	(0.0)	0.8	0.6	0.5	0.4	0.3	0.3	0.4
53	Unallocated[3]	2.0											
54	Total	180.2	212.4	189.6	91.1	170.9	184.1	200.7	210.2	209.5	217.2	219.5	227.7
55	Current Benefits (Statutory)	25.3	26.8	25.3	26.8	32.3	39.2	39.6	41.1	40.3	42.6	41.9	43.1
56	Current Benefits (Non-Statutory)	16.0	21.0	19.9	20.5	19.3	26.9	26.4	28.2	28.5	29.4	29.6	30.6
57	Pension & OPEB (Current Service)[1]	139.1	164.5	144.4	43.9	119.4	118.0	134.7	140.8	140.7	145.2	148.0	154.0
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	13.4	13.5	13.3	12.3	12.3	13.6	12.0	12.0	11.7	11.8	11.1	11.3
59	Non-Executive Management	86.7	83.9	85.3	80.1	99.2	114.8	106.6	112.3	111.4	111.2	109.9	111.6
60	Management Subtotal	100.2	97.4	98.6	92.4	111.5	128.4	118.6	124.2	123.1	123.0	121.0	122.9
61	Society	224.9	254.2	232.5	229.3	275.5	316.8	320.5	333.7	327.7	333.2	335.4	344.3
62	PWU	300.2	351.6	283.8	267.2	345.7	334.2	357.2	396.5	389.7	425.2	420.4	434.8
63	Term/ETE/PECO Temp	5.1	11.6	26.7	40.8	35.7	13.3	16.9					
64	EPSCA	14.5	19.5	21.6	20.7	25.1	18.7	13.6	10.4	9.4	7.2	7.1	8.1
65	Unallocated[3]	5.1											
66	Total	650.0	734.4	663.2	650.3	793.4	811.4	826.9	864.8	849.9	888.6	883.9	910.1

[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)

[4]Excludes Provision, Refurbishment and New Nuclear Growth

FTE, Compensation and Benefit Information for OPG's Nuclear Pickering Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Pickering NGS[4]	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**
	Pickering - Direct												
1	Executive	15.9	10.9	12.3	11.6	13.7	12.8	11.2	7.4	7.7	7.9	7.8	12.2
2	Non-Executive Management	255.8	184.8	187.4	202.9	205.0	169.4	156.7	81.4	82.4	94.2	99.7	152.7
3	Management Subtotal	271.7	195.8	199.7	214.5	218.7	182.2	167.9	88.8	90.1	102.1	107.5	165.0
4	Society	986.6	840.1	771.5	835.1	866.8	705.1	666.6	313.2	327.1	373.9	390.4	578.0
5	PWU	1,751.8	1,489.9	1,318.1	1,386.5	1,488.3	1,254.2	1,114.9	539.8	560.0	583.5	589.3	976.2
6	Term/ETE/PECO Temp	564.8	692.1	753.7	715.0	404.7	142.2	74.7					
7	EPSCA	26.8	21.6	19.3	23.9	24.5	10.2	3.4	9.5	9.5	9.5	8.1	7.0
8	Subtotal	3,601.7	3,239.5	3,062.3	3,175.0	3,003.0	2,293.9	2,027.5	951.3	986.7	1,068.9	1,095.2	1,726.1
	Pickering - Allocated												
9	Executive	9.2	8.6	10.4	11.8	11.1	12.0	13.2	13.2	13.9	14.3	14.9	14.2
10	Non-Executive Management	108.5	102.7	112.9	137.0	145.1	159.0	160.0	147.7	153.1	157.0	163.6	164.0
11	Management Subtotal	117.6	111.3	123.3	148.8	156.3	171.1	173.2	160.9	167.0	171.4	178.5	178.2
12	Society	184.8	158.5	183.4	260.5	279.9	302.5	297.6	283.2	288.0	292.5	297.8	307.6
13	PWU	201.4	184.3	216.8	239.1	242.7	185.8	170.1	131.8	131.9	131.1	132.1	166.1
14	Term/ETE/PECO Temp	42.6	54.1	53.6	40.3	32.9	19.5	15.9					
15	EPSCA	25.5	24.6	14.1	14.7	9.9	10.7	15.0	10.7	10.7	10.7	10.7	10.7
16	Subtotal	571.9	532.9	591.3	703.4	721.7	689.5	671.8	586.6	597.6	605.7	619.1	662.6
	Pickering GS Facilities												
17	Executive	25.1	19.5	22.7	23.4	24.9	24.9	24.4	20.6	21.6	22.2	22.7	26.5
18	Non-Executive Management	364.3	287.6	300.3	340.0	350.1	328.4	316.7	229.1	235.5	251.2	263.3	316.8
19	Management Subtotal	389.3	307.1	323.0	363.3	374.9	353.3	341.1	249.7	257.1	273.4	286.0	343.2
20	Society	1,171.3	998.6	954.9	1,095.7	1,146.7	1,007.6	964.2	596.4	615.1	666.4	688.2	885.6
21	PWU	1,953.2	1,674.2	1,534.9	1,625.6	1,731.0	1,440.0	1,285.0	671.7	691.9	714.5	721.4	1,142.3
22	Term/ETE/PECO Temp	607.4	746.2	807.3	755.3	437.6	161.7	90.6					
23	EPSCA	52.3	46.2	33.5	38.6	34.4	21.0	18.4	20.2	20.2	20.2	18.8	17.7
24	Total	4,173.6	3,772.4	3,653.6	3,878.5	3,724.7	2,983.5	2,699.3	1,538.0	1,584.3	1,674.6	1,714.4	2,388.7
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	5.8	4.5	5.7	5.4	6.7	6.5	6.4	5.6	5.9	6.3	6.5	7.7
26	Non-Executive Management	50.5	42.9	47.4	51.8	52.5	52.9	53.0	39.9	41.8	46.0	50.1	62.6
27	Management Subtotal	56.3	47.4	53.2	57.3	59.2	59.4	59.5	45.4	47.8	52.3	56.6	70.3
28	Society	153.1	146.6	130.4	162.2	175.0	162.4	158.4	102.3	107.2	118.8	128.9	172.9
29	PWU	230.5	216.8	193.4	230.4	263.7	192.0	182.6	96.7	102.1	108.0	115.3	189.1
30	Term/ETE/PECO Temp	64.9	86.3	94.1	97.8	56.6	18.6	11.0					
31	EPSCA	8.0	8.2	5.3	5.3	5.1	3.3	3.0	3.7	3.8	4.0	3.7	3.6
32	Unallocated[3]	(2.8)											
33	Total	509.9	505.3	476.4	552.9	559.6	435.6	414.5	248.2	260.9	283.0	304.5	435.9
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	3.1	2.7	2.6	3.6	3.5	3.7	3.7	3.7	4.1	4.3	4.4	4.7
35	Non-Executive Management	9.1	9.1	7.7	12.2	13.8	15.2	14.5	14.7	15.9	17.0	17.5	18.4
36	Management Subtotal	12.2	11.8	10.3	15.7	17.3	18.9	18.2	18.4	20.0	21.3	21.9	23.1
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society (Regular)	2.8	2.5	2.5	2.5	2.8	1.3	1.2	1.2	1.1	0.9	0.9	0.8
38	PWU (Regular)	6.3	7.0	6.4	6.6	6.7	3.4	3.2	3.0	2.9	2.5	2.2	0.5
	Total	9.1	9.5	9.0	9.2	9.4	4.8	4.4	4.1	4.0	3.4	3.1	1.3
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
38	Society	18.0	17.0	21.2	22.1	20.1	12.6	8.7	3.9	4.0	4.2	4.4	8.3
39	PWU	39.6	36.2	34.7	42.2	45.1	31.3	22.8	16.9	16.8	17.3	17.7	26.9
40	Term/ETE/PECO Temp	8.3	10.1	13.0	15.6	8.1	3.1	2.5					
41	EPSCA	0.9	0.9	0.8	0.9	6.0	0.0	0.2	0.8	0.8	0.8	0.7	0.6
42	Unallocated[3]												
43	Total	66.8	64.2	69.7	80.8	73.9	46.9	34.3	21.6	21.6	22.3	22.7	35.8
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
44	Executive	3.2	3.1	3.1	2.1	2.5	2.3	2.5	2.1	2.2	2.4	2.5	3.0
45	Non-Executive Management	26.0	24.9	25.7	15.6	23.1	17.9	19.9	14.3	14.9	16.9	18.3	23.2
46	Management Subtotal	29.2	28.0	28.8	17.7	25.7	20.2	22.4	16.4	17.2	19.3	20.7	26.1
47	Society	76.7	77.9	75.3	54.2	77.0	54.5	58.4	34.5	36.6	42.4	45.9	64.7
48	PWU	102.3	98.0	89.9	66.7	95.3	62.3	63.3	30.2	31.9	35.0	37.1	68.6
49	Term/ETE/PECO Temp	4.7	5.5	6.5	6.7	4.7	1.2	0.8					
50	EPSCA	0.5	(0.0)	0.3	0.4	0.3	0.1	0.1	0.2	0.2	0.2	0.2	0.2
51	Unallocated[3]	1.5											
52	Total	215.0	209.4	200.8	145.7	203.0	138.3	145.0	81.3	85.9	96.9	103.9	159.6
53	Current Benefits (Statutory)	33.0	29.5	32.3	35.4	37.1	31.4	28.7	16.9	18.0	20.0	20.8	30.4
54	Current Benefits (Non-Statutory)	18.1	20.4	20.2	21.5	21.8	20.8	19.8	12.3	13.1	14.7	15.3	22.5
55	Pension & OPEB (Current Service)[1]	163.7	159.5	148.3	88.8	144.0	86.1	96.5	52.1	54.8	62.2	67.8	106.7
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
56	Executive	12.0	10.3	11.4	11.1	12.7	12.5	12.6	11.4	12.3	13.0	13.3	15.4
57	Non-Executive Management	85.6	76.9	80.8	79.6	89.5	86.0	87.4	68.8	72.7	79.9	85.9	104.1
58	Management Subtotal	97.6	87.2	92.3	90.7	102.1	98.5	100.1	80.2	84.9	92.9	99.2	119.5
59	Society	250.6	244.0	229.5	241.1	274.9	230.9	226.7	141.9	149.0	166.3	180.0	246.6
60	PWU	378.7	358.0	324.4	345.8	410.8	288.9	271.9	146.7	153.6	162.9	172.3	285.1
61	Term/ETE/PECO Temp	77.8	101.9	113.6	120.1	69.4	22.9	14.3					
62	EPSCA	9.4	9.1	6.4	6.6	11.4	3.5	3.4	4.7	4.8	5.0	4.6	4.4
63	Unallocated[3]	(1.2)											
64	Total	812.9	800.2	766.2	804.3	863.1	644.6	616.3	373.5	392.3	427.0	456.1	655.7

[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)

[4]Excludes Provision, Refurbishment and New Nuclear Growth

Table 32
Calculation of Regulatory Income Taxes for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Years Ending December 31, 2026-2031

Line No.	Particulars	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(b)	(c)	(d)	(e)	(f)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	0.0	0.0	0.2	112.7	536.4
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		0.0	0.0	0.0	20.4	98.9
3	**Pension and OPEB Accrual**	4	14.1	13.3	11.9	10.1	9.5
4	**Restricted Net Interest and Financing Expense**		0.0	0.0	0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0	0.0	0.0
7	**Total Additions**		14.1	13.3	11.9	30.5	108.4
	Deductions for Regulatory Tax Purposes:						
8	**CCA**	2	268.2	385.6	325.2	337.4	334.5
9	**Pension Plan Contributions**	4	1.4	0.3	0.4	0.2	0.3
10	**OPEB Payments**	4	12.7	13.0	11.5	9.9	9.2
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0	0.0	0.0
14	**Total Deductions**		282.3	398.9	337.1	347.5	344.0
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(268.2)	(385.6)	(325.0)	(204.3)	300.8
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5	60.3	86.8	73.1	46.0	(67.7)
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5	207.8	298.8	251.9	158.3	(233.1)
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	3	0.0	0.0	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 18 x line 24)		0.0	0.0	0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 18 x line 25)		0.0	0.0	0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-Controlling Partners** (line 21 x 22.5%)		0.0	0.0	0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0	0.0	0.0
	Income Tax Rate:						
24	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
26	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see L-F4-CCC-084, Table 34.

Table 34
Notes to L-F4-CCC-084, Table 32
Calculation of Regulatory Income Taxes for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Years Ending December 31, 2027-2031

Notes:
1 Regulatory Earnings Before Tax for the Darlington New Nuclear Program from 2027 - 2031 are calculated as follows :

Line No.	Item	Reference	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Darlington New Nuclear Program	Ex. L-F4-CCC-084, Table 56, line 11	0.0	0.0	0.2	112.7	536.4
2a	Additions for Regulatory Tax Purposes	line 7	14.1	13.3	11.9	30.5	108.4
3a	Deductions for Regulatory Tax Purposes	line 14	282.3	398.9	337.1	347.5	344.0
4a		line 1a + line 2a - line 3a	(268.2)	(385.6)	(325.0)	(204.3)	300.8
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(40.2)	(57.8)	(48.7)	(30.6)	45.1
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(26.8)	(38.6)	(32.5)	(20.4)	30.1
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(67.0)	(96.4)	(81.2)	(51.1)	75.2
9a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	40.2	57.8	48.7	30.6	(45.1)
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	26.8	38.6	32.5	20.4	(30.1)
11a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	67.0	96.4	81.2	51.1	(75.2)
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.0	0.0	0.2	112.7	536.4
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.0	0.0	0.2	112.7	536.4

2 Amounts are from Ex. L-F4-CCC-084, Tables 49-53, col. (j) - (i).
3 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR term, the loss is applied (carried back or carried forward) to reduce the DNNP's taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms.
4 The DNNP facilities will pay OPG its attributed portion of OPG's pension and OPEB accrual costs under the respective agreements. As a result, its pension plan contributions and OPEB payments are equivalent to its pension and OPEB accrual.
5 DNNP LP is a limited partnership in which tax-exempt investors are expected to hold a stake of 22.5% and therefore, the DNNP facilities' revenue requirement only reflects the impact of the remaining 77.5% of the tax loss or income.

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[1]

	OPG Nuclear Facilities	Regulated Hydroelectric Facilities
2022	8.5%	6.7%
2023	8.5%	9.2%
2024	8.5%	6.3%
2025	8.8%	6.7%
2026	9.0%	8.4%
2027	9.1%	9.9%
2028	8.5%	8.4%
2029	8.5%	7.9%
2030	8.5%	7.5%
2031	8.4%	7.1%

[1] Derived by dividing the annual Capital Cost Allowance by Reduced Undepreciated Capital Cost amount for that year.

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

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

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

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DNNP Rate Base (Ex. B3-1-1, Table 2, lines 12 and 24)		0.0	0.0	0.0	1,360.5	6,507.4
2	Weighted Average Cost of Capital	1	0.00%	0.00%	0.00%	9.11%	9.11%
3	**Cost of Capital** (line 1 x line 2)		**0.0**	**0.0**	**0.0**	**123.9**	**592.8**
	Depreciation						
4	DNNP (Ex. F4-1-1, Table 2, line 12)		0.0	0.0	0.0	22.6	109.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 100% x 9.11%)		0.0	0.0	0.0	123.9	592.8
6	Depreciation (line 4)		0.0	0.0	0.0	22.6	109.7
7	CCA (Ex. F4-2-1, Table 3g, line 8)		(195.5)	(311.1)	(345.0)	(365.6)	(377.3)
8	**Net Increase (Decrease) in Regulatory Taxable Income** ([line 5 + line 6 + line 7] x 77.5%)	2	**(151.5)**	**(241.1)**	**(267.4)**	**(169.8)**	**252.1**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(50.5)**	**(80.4)**	**(89.1)**	**(56.6)**	**84.0**
11	**Total DNNP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(50.5)**	**(80.4)**	**(89.1)**	**90.0**	**786.6**

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

2 DNNP LP is a limited partnership in which tax-exempt investors are expected to hold a stake of 22.5% and therefore, the DNNP facilities' revenue requirement only reflects the impact of the remaining 77.5% of the tax loss or income.

Change of Laws Deferral Account (OPG)
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the Change of Laws Deferral Account (OPG), effective January 1, 2027, to record impacts to costs and revenues for the regulated facilities resulting from legislative or regulatory changes ("change of laws") to the extent these impacts are not already reflected in the approved revenue requirement and the approved production forecast, or another deferral or variance account, as applicable, and result in a financial impact for OPG's prescribed facilities of $20M or greater on an annualized basis.

Entry 1: Impact resulting from change of laws on revenue

Entry	Debit	Credit
DR/CR Revenue	x,xxx	x,xxx
CR/DR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx

To record the impact resulting from changes of laws on revenue.

Entry 2: Impact resulting from change of laws on capital costs

Entry	Debit	Credit
DR/CR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

To record the impact resulting from changes of laws on depreciation, the associated impacts on the return on rate base, and any tax impacts.

Entry 3: Impact resulting from change of laws on non-capital costs

Entry	Debit	Credit
DR/CR Change of Laws Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from change of laws on non-capital expenses.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Change of Laws Deferral Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Global Hydroelectric Capital Variance Account
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the asymmetrical Global Hydroelectric Capital Variance Account, effective January 1, 2027, to record a credit to ratepayers equal to the amount, if any, by which the total actual capital-related revenue requirement ("CRRR") for the regulated hydroelectric facilities over the 2028-2031 period is lower than the forecast CRRR underpinning the capital factor used to set hydroelectric payment amounts, as assessed after the 2028-2031 period.

Entry	Debit	Credit
DR Depreciation Expense	x,xxx	
DR Return on Rate Base	x,xxx	
DR Income Tax Expense	x,xxx	
CR Global Hydroelectric Capital Variance Account		x,xxx

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully refunded.

OPG shall file the balance in the Global Hydroelectric Capital Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Clean Electricity ITC Variance Account (OPG)
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the Clean Electricity ITC Variance Account (OPG), effective January 1, 2027, to record the revenue requirement differences between the actual Clean Electricity Investment Tax Credits (“CEITCs) received for the regulated facilities and such amount reflected in the OEB-approved payment amounts for OPG’s hydroelectric and nuclear facilities, including the income tax impacts arising from such differences, to the extent these impacts are not already reflected in another deferral or variance account.

Entry	**Debit**	**Credit**
DR/CR Clean Electricity ITC Variance Account	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Clean Electricity ITC Variance Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Payment Amount Shaping Deferral Account
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the Payment Amount Shaping Deferral Account, effective January 1, 2027, to record OPG's payment amount shaping amounts approved by the OEB for the 2027-2031 rate term, such period being "the deferral period".

The offsetting annual payment amount shaping amounts shall be recorded monthly on a straight-line basis, such that a nil balance remains in the account at the end of the deferral period excluding interest.

Entry	**Debit**	**Credit**
DR/CR Payment Amount Shaping Deferral Account	x,xxx	x,xxx
CR/DR Revenue	x,xxx	x,xxx

OPG shall record interest on the balance in the account at the following OEB-approved long-term debt rates reflecting OPG's cost of long-term borrowing, compounded annually: 4.58% for 2027, 4.78% for 2028, 4.90% for 2029, 4.97% for 2030 and 4.98% for 2031.

OPG shall file the balance in the Payment Amount Shaping Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

DNNP Nuclear Liability Deferral Account
Ontario Power Generation Inc.
Illustrative Accounting Order

Scope of Account

OPG shall establish the DNNP Nuclear Liability Deferral Account, effective January 1, 2027, to record the difference between: (i) the costs of OPG's nuclear facilities decommissioning and nuclear waste management liabilities ("nuclear liabilities") with respect to the Darlington New Nuclear Program ("DNNP") facilities, as reflected in OPG's audited annual financial statements approved by OPG's Board of Directors; and, (ii) the costs of the nuclear liabilities with respect to the DNNP facilities reflected in OPG's nuclear revenue requirement approved by the OEB.

Entry	Debit	Credit
DR/CR DNNP Nuclear Liability Deferral Account	x,xxx	x,xxx
CR/DR Asset Retirement Cost Depreciation Expense	x,xxx	x,xxx
CR/DR Used Fuel Storage and Disposal Variable Expense	x,xxx	x,xxx
CR/DR Low & Intermediate Level Waste Management Variable Expense	x,xxx	x,xxx
CR/DR Accretion Expense	x,xxx	x,xxx
CR/DR Earnings on Nuclear Funds	x,xxx	x,xxx
CR/DR Income Tax Expense		

OPG shall not record interest on the balance of this account.

OPG shall file the balance in the DNNP Nuclear Liability Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Pension and OPEB Cost Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Pension and OPEB Cost Variance Account (DNNP), effective January 1, 2027, to record the difference between (i) the pension and other post-employment benefit ("OPEB") costs, plus related income tax payments, reflected in the revenue requirement approved by the OEB; and (ii) DNNP LP's actual pension and OPEB costs, and associated income tax impacts, for the DNNP LP facilities.

Entry	Debit	Credit
DR/CR Pension and OPEB Cost	x,xxx	x,xxx
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Pension and OPEB Cost Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall not record any interest on the balance of this account.

DNNP LP shall file the balance in the Pension and OPEB Cost Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP), effective January 1, 2027, to record the difference between the amounts approved for recovery or repayment in the DNNP LP deferral and variance accounts and the actual amounts recovered or repaid based on actual nuclear production and approved riders. The account shall also capture the transfer of balances remaining in other DNNP LP accounts as they expire from time to time.

Entry	Debit	Credit
DR/CR Revenue	x,xxx	x,xxx
CR/DR Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

SR&ED ITC Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the SR&ED ITC Variance Account (DNNP), effective January 1, 2027, to record the difference between actual Scientific Research & Experimental Development investment tax credits (“SR&ED ITCs”) attributed to the DNNP facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the DNNP LP revenue requirement approved by the OEB, including the tax on the difference. The forecast SR&ED ITCs included in the proposed DNNP LP revenue requirements for the 2027-2031 period are $0.0M per year[1] or $0.0M per month.

Entry	Debit	Credit
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR SR&ED ITC Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the SR&ED ITC Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[1] Ex. F4-2-1, Table 3g, line 21.

Income and Other Taxes Variance Account (DNNP)
DNNP LP
illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Income and Other Taxes Variance Account (DNNP) to record the financial impact on revenue requirement of the following:

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

Entry	Debit	Credit
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Income and Other Taxes Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance of this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Income and Other Taxes Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Impact for IFRS Deferral Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Impact for IFRS Deferral Account (DNNP), effective January 1, 2027, to record financial impacts of transition to and implementation of International Financial Reporting Standards ("IFRS") from United States Generally Acceptable Accounting Principles ("US GAAP") in the event that DNNP LP adopts IFRS for financial reporting purposes.

Entry	Debit	Credit
DR/CR Impact for IFRS Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Applicable Financial Statement Elements	x,xxx	x,xxx

Entries shall include, but not be limited to, unamortized gains/losses and past service costs/credits balances recorded for pension and other post-employment benefit plans in accumulated other comprehensive income/loss under US GAAP.

DNNP LP shall file the balance in the Impact for IFRS Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

DNNP LP shall not record any interest on the balance of this account.

Clean Electricity ITC Variance Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Clean Electricity ITC Variance Account (DNNP), effective January 1, 2027, to record the revenue requirement differences between the actual Clean Electricity Investment Tax Credits ("CEITCs") received for the DNNP facilities and such amount reflected in the OEB-approved payment amounts for the DNNP facilities, including the income tax impacts arising from such differences, to the extent these impacts are not already reflected in another deferral or variance account.

Entry	Debit	Credit
DR/CR Clean Electricity ITC Variance Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered.

DNNP LP shall file the balance in the Clean Electricity ITC Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Impact of Change in Tax Status Variance Account
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Impact of Change in Tax Status Variance Account, effective January 1, 2027, to record the impact on regulatory income taxes or capital taxes reflected in the revenue requirement approved by the OEB of any changes to the income tax status of any DNNP LP's partners or as a result of a change in the partners of DNNP LP.

Entry	Debit	Credit
DR/CR Impact of Change in Tax Status Variance Account	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Impact of Change in Tax Status Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Change of Laws Deferral Account (DNNP)
DNNP LP
Illustrative Accounting Order

Scope of Account

DNNP LP shall establish the Change of Laws Deferral Account, effective January 1, 2027, record impacts to costs and revenues for the regulated facilities resulting from legislative or regulatory changes (“change of laws”) to the extent these impacts are not already reflected in the approved revenue requirement or the approved production forecast, or another deferral or variance account, as applicable, and result in a financial impact for the DNNP facilities of $10M or greater on an annualized basis.

Entry 1: Impact resulting from change of laws on revenue

Entry	Debit	Credit
DR/CR Revenue	x,xxx	x,xxx
CR/DR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx

To record the impact resulting from changes of laws on revenue.

Entry 2: Impact resulting from change of laws on capital costs

Entry	Debit	Credit
DR/CR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

To record the impact resulting from changes of laws on depreciation, the associated impacts on the return on rate base, and any tax impacts.

Entry 3: Impact resulting from change of laws on non-capital costs

Entry	Debit	Credit
DR/CR Change of Laws Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from change of laws on non-capital costs.

DNNP LP shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Change of Laws Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Board Staff Interrogatory #055

Interrogatory

Reference:
Ref 1: Exhibit H1 / Tab 2 / Schedule 1 / p. 2

Preamble:

At Reference 1, OPG states that the nuclear payment amount rider set through this proceeding shall be calculated as (E + F) / (C + D), where "E" is the sum of the balances proposed for clearance in deferral and variance accounts for OPG's regulated balances proposed for clearance in deferral and variance accounts for OPG's regulated nuclear facilities, "F" is the sum of the balances proposed for clearance in deferral and variance accounts for the Darlington New Nuclear Program (DNNP) facilities, and "C" and "D" are the OEB-approved production forecasts for OPG's regulated nuclear facilities and the DNNP facilities, respectively.

Question(s):

a) Please confirm and quantify whether concurrent cost recovery (CCR) amounts are included in, as applicable:
   i. "E", the regulated nuclear facilities, or
   ii. "F", the DNNP facilities

b) Please provide a scheduled isolating the CCR's impact on the nuclear payment amount rider ($/MWh) for each year 2027-2031.

c) Please provide a bill impact analysis isolating CCR from all other nuclear revenue requirement drivers.

d) Please confirm whether CCR recovery is grossed-up for income taxes within the revenue requirement. If CCR interest is not grossed-up directly, please explain how the associated income tax effects are reflected in the determination of the payment amounts.

Response

a) and b)

There are no CCR amounts included in “E” or “F” as part of the proposed payment riders in this proceeding. In accordance with O. Reg. 53/05, CCR amounts are included, on a forecast basis, in OPG and DNNP LP’s nuclear revenue requirements and resulting blended nuclear payment amounts proposed in this proceeding.

For clarity, as stated at Ex. H1-2-1, p. 2, footnote 3, “[the] amount in “F” is equal to zero as the Application is not proposing clearance of any deferral and variance accounts for the DNNP facilities.” The amount in “E” is per Ex. H1-2-1, Table 2, line 32 and represents the sum of the balances proposed for clearance in the deferral and variance accounts for OPG’s nuclear facilities as of year-end 2024. There are no CCR amounts included in those balances.

c) The requested bill impact analysis isolating the CCR amounts sought in this Application is included in Chart 1 below. This analysis reflects the format, methodology and applicable inputs used to produce Ex. I1-1-2, Table 1 that determines the estimated typical residential consumer impacts of the Application, but only considering the requested CCR amounts. For clarity, this analysis does not reflect the effect of the revenue requirement reductions arising from the lower rate base under the CCR mechanism (refer to Ex. L-D4-Staff-134), which will endure over the life of the respective assets.

Chart 1 - Annualized Residential Consumer Impact of CCR Amounts

	2027	2028	2029	2030	2031	Avg
Typical Consumption (kWh/month)	787	787	787	787	787	787
Typical Usage of OPG and DNNP LP Generation (kWh/month)	246	284	276	287	304	280
Typical Bill ($/month)	142.10	142.10	142.10	142.10	142.10	142.10
Typical Bill Impact ($/month)	2.46	0.83	1.18	0.38	(2.41)	0.49
Typical Bill Impact (%)	1.7%	0.6%	0.8%	0.3%	(1.7%)	0.3%
Prior Year Weighted Avg ($/MWh)	0.00	10.02	12.93	17.19	18.50	
Current Year Weighted Avg ($/MWh)	10.02	12.93	17.19	18.50	10.59	
Change in Weighted Avg ($/MWh)	10.02	2.91	4.26	1.31	(7.91)	
Total Regulated Production (TWh)	51.2	59.2	57.5	59.8	63.3	
Forecast 2027 Provincial Demand (TWh)	163.9	163.9	163.9	163.9	163.9	
Proportion of Customer Usage	31.2%	36.1%	35.1%	36.5%	38.6%	

d) The recovery of the CCR amounts is not “grossed-up” for income taxes within OPG and DNNP LP’s proposed revenue requirements. As interest costs are generally tax deductible, OPG’s regulatory income tax calculations at Ex. F4-2-1, Tables 3d and 3g do not treat CCR as requiring an adjustment to regulatory earnings before tax. This results in no income tax effect being included in the proposed regulatory income taxes in respect of the CCR amounts.

Board Staff Interrogatory #257

Interrogatory

Reference:
Ref 1: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

OPG proposes several new deferral and variance accounts in this application including, but not necessarily limited to, the Global Hydroelectric Capital Variance Account, Payment Amount Shaping Deferral Account, Change of Laws Deferral Account (OPG), and Clean Electricity Investment Tax Credit Variance Account (OPG).

Question(s):

a) If the account is not expressly established by regulation, a discussion of why the proposed account is appropriate, including:
   i. Causation, i.e. why the proposed amounts are outside the forecast amounts or rate base on which payments amounts were derived
   ii. Materiality, including an estimate of the expected magnitude of the balance and why it is expected to be material
   iii. Prudence, i.e. how OPG will identify and record the proposed amounts reliably

b) Please explain why the underlying cost, credit, or risk is not part of OPG's ordinary business risk.

c) Please provide a draft accounting order including illustrative entries.

Response

a) The requested information is provided below.[1,2]

   Global Hydroelectric Capital Variance Account
   Causation
   The Global Hydroelectric Capital Variance Account is proposed in conjunction with the requested hydroelectric rate-setting framework in Ex. A1-3-2, Section 2.0. The account is designed to address a scenario where the capital-related revenue

[1] The discussion does not include those accounts proposed by DNNP LP that mirror applicable existing accounts for OPG.
[2] The discussion does not include the proposed DNNP Nuclear Liability Deferral, which OPG views as being necessary to enable the operation of O. Reg. 53/05, section 6(2)10.1.

requirement determined based on OPG's actual capital in-service amounts for the prescribed hydroelectric facilities over the 2028-2031 period is less than the capital-related revenue requirement afforded through the payment amounts inclusive of the proposed C-factor. As the account is asymmetric in favour of ratepayers, the only amounts that could be recorded in the account are credit amounts due to the actual capital-related revenue requirement being lower than such amount underpinning the C-factor. Thus, by their nature, these potential credit amounts are outside the forecast amounts that would underpin payment amounts.

Materiality

In Ex. A1-3-2, Section 4.3, the Applicants propose to increase the regulatory materiality threshold applicable to OPG's regulated hydroelectric and nuclear businesses to $20M. The capital-related revenue requirements underpinning the C-factor are $978.5M in 2028, $1,100.7M in 2029, $1,176.6M in 2030, and $1,231.4M in 2031.[3] A $20M variance would represent approximately 2% of these annual amounts. While OPG does not anticipate variances in a particular direction, on a portfolio of this size, it is inherently plausible that a variance of 2% or greater could materialize.

Prudence

The nature of the amounts and the proposed process for recording them in the account is detailed in Ex. A1-3-2, Section 2.3.5, and further discussed in Ex. L-H1-Staff-253.

<u>Payment Amount Shaping Deferral Account</u>

Causation

As stated in Ex. H1-1-1, p. 65, the Payment Amount Shaping Deferral Account "is proposed in conjunction with OPG's payment amount shaping proposal to help manage the 2027 ratepayer impact while balancing OPG's financing needs over the period." The proposal to defer collection of OPG's 2027 recoverable nuclear revenue requirement by $500M in 2027 and increase it by $500M in 2028 demonstrates, by its nature, that the amount recorded in the account would be outside the forecasts that otherwise underpin the payment amounts.

Materiality

The proposed annual deferral amounts of $500M in 2027 and $(500)M in 2028 exceed the proposed regulatory materiality threshold of $20M.

Prudence

The nature of the amounts and the proposed process for recording them in the account is detailed in Ex. H1-1-1, Section 7.4 and Ex. I1-3-2.

[3] Ex. I1-2-1, Table 2, line 7.

Change of Laws Deferral Accounts (OPG and DNNP LP accounts)

Causation

As noted in Ex. H1-1-1, p. 61:

> [A]side from expected changes to the nuclear liability insurance limit under the Nuclear Liability and Compensation Act described in Ex. F4-4-1, Section 4.2, [OPG's] 2025-2031 Business Plan and **the proposed forecasts in this Application do not include any changes in laws that may occur over the IR term** unless captured by an existing account. As such, OPG proposes to establish a deferral account to capture material cost and revenue impacts to OPG's regulated hydroelectric and nuclear facilities arising from provincial and/or federal legislative or regulatory changes…, to the extent these impacts are not already recorded in other deferral and variance accounts.

Emphasis added.

The highlighted statement noting that the forecasts underpinning the Application do not include changes in law supports the causation criteria. The account is proposed to address impacts that are entirely outside the costs proposed for recovery, and the production forecasts over which such recovery is proposed, by the Applicants in this Application. An illustrative example of the type of impacts that would be eligible for recording in the account is provided in Ex. L-H1-SEC-214.

Materiality

As described above, the Applicants are proposing that the accounts only capture material cost and revenue impacts. The Applicants propose to determine materiality for the purposes of the Change of Laws Deferral Accounts using the proposed materiality thresholds of $20M for OPG and $10M for DNNP LP under the respective rate-setting frameworks, as set out in Ex. A1-3-2, Section 4.3, on an annualized revenue requirement or revenue basis, as applicable.

Prudence

In Ex. H1-1-1, pp. 62-63, OPG provides an explanation of how the account could operate using American eel legislation as an example. In that exhibit, OPG states that "if OPG's regulated hydroelectric facilities are faced with compliance activities related to such changes over the 2027-2031 IR term, OPG would use the proposed Change of Laws Deferral Account (OPG) to record the revenue requirement impact of costs associated with these compliance activities, as well as the impact of

foregone production revenue, net of changes in GRC costs, at OPG's regulated hydroelectric facilities." Further discussion on the mechanics of these proposed accounts and how the interactions with existing accounts are proposed to be addressed can be found in Ex. L-H1-Staff-259.
The Applicants propose that this process would be followed for any potential material change in legal or regulatory requirement during the IR term. This process would ensure that potential impacts on all elements of revenue requirement and production revenue are addressed wholistically.

Clean Electricity ITC Variance Accounts (OPG and DNNP LP)

Causation

As stated at Ex. H1-1-1, pp. 63 and 70, "no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan or the proposed revenue requirements in this Application". This supports the causation criteria, demonstrating that amounts are outside the forecasts that would be underpinning the payment amounts. Furthermore, while legislation instituting the Clean Electricity Investment Tax Credit ("CEITC") has since become law on March 26, 2026, had this event occurred prior to the filing date of the Application and forecasted impacts of the CEITCs had been reflected in the revenue requirement, the causation criteria would still have been met given the uncertainties regarding the meeting of specific eligibility requirements and the actual amounts of the CEITCs received, as further discussed in Ex. L-F4-CCC-084.

Materiality

Refer to Ex. L-F4-CCC-084 for the estimated impact related to the CEITCs on the respective proposed revenue requirements in the Application. On average, these impacts exceed the proposed $20M materiality threshold for OPG's facilities and the proposed $10M materiality threshold for the DNNP facilities.

Prudence

The nature of the amounts and the proposed process for recording them in the account is presented in Ex. H1-1-1, Sections 7.3 and 8.6, and Ex. F4-2-1, Section 3.5.

As described in Ex. F4-2-1, p. 20, "the recognized CEITCs will reduce in-service rate base, associated depreciation expense and cost of capital amounts and the attendant tax effects, while reducing the available CCA deductions". This is the basis for the revenue requirement impact of the CEITCs that the Applicants propose to record in the Clean Electricity ITC Variance Accounts. This basis is comprehensively illustrated in Ex. L-F4-CCC-084, Attachment 1 materials.

Impact of Change in Tax Status Variance Account (DNNP)

Causation

As discussed in Ex. H1-1-1, Section 8.7, the Impact of Change in Tax Status Variance Account (DNNP) is proposed "to record the impact on the forecast regulatory income taxes reflected in revenue requirement approved by the OEB from any changes to the tax status of DNNP LP's partners." With DNNP LP's partners, rather than DNNP LP itself as a limited partnership, being subject to income tax, this account is necessary in the event that the regulatory income taxes included in DNNP LP's revenue requirements do not reflect the correct tax status of the DNNP LP partners. As discussed in Ex. F4-3-2, p. 4, lines 6-21, the non-OPG partners are currently tax exempt and there is therefore no tax allowance considered in the proposed revenue requirements in respect of their ownership portion. On this basis, the potential amounts eligible for the account are inherently outside the forecasts underpinning payment amounts.

Materiality

The potential magnitude of amounts recorded in the account depends on the share of partnership taxable income attributable to the partner(s) subject to a change in tax status.

Prudence

DNNP LP proposes to determine the impact on the forecast regulatory income taxes reflected in revenue requirement by recalculating the income tax expense amounts at Ex. I1-1-1, Table 2a, line 21 and Ex. F4-2-1, Table 3g using the tax status of the partners after a change in status.

b) In the case of the Global Hydroelectric Capital Variance Account and the Payment Amount Shaping Deferral Account, the accounts are proposed in conjunction with elements of the Applicants' proposed rate-setting frameworks. These accounts are not designed to reduce business risk.

In the case of the Clean Electricity ITC Variance Accounts and Impact of Change in Tax Status Variance Account, the accounts are proposed to address uncertainty at the time of filing. The Clean Electricity ITC Variance Accounts ensure that ratepayers receive applicable tax benefits if realized by the Applicants; they are not designed to reduce business risk.

As noted above in the response to part a), the Impact of Change in Tax Status Variance Account is necessary in the event that the regulatory income taxes included in DNNP LP's revenue requirements do not reflect the correct tax status of the DNNP LP partners. This potential for a partner to become subject to tax is not an ordinary business risk for DNNP LP.

With respect to the Change of Laws Deferral Accounts, the purpose of the accounts is to address changes in laws and regulations that are outside of the Applicants' control and have material impact on costs and revenues. While the Applicants monitor potential development in this area, they are unable to predict whether any particular laws or regulation changes will ultimately materialize. The Applicants also believe that the making of the request for the account during this proceeding, prior to any settlement or decision, is consistent with the OEB's decision in EB-2023-0098, that where OPG identified a known variable, "OPG should have taken into consideration and governed themselves accordingly, for example by identifying the issue and also by seeking a specific variance account as part of their application."

c) Refer to Ex. L-H1-SEC-204.