ONTARIO POWER GENERATION

Andrea Brown
Director, Ontario Regulatory Affairs

1908 Colonel Sam Dr. Oshawa, ON L1H 8W8 905-623-6670 andrea.brown@opg.com

May 15, 2026

VIA RESS AND EMAIL

Mr. Ritchie Murray
Acting 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") – Interrogatory Responses- Staff Expert IRs

Interrogatory Responses

Consistent with Procedural Order 2, attached are the Applicants' responses to interrogatories filed by OEB staff experts on May 1, 2026. The Applicants have submitted these documents through the Regulatory Electronic Submissions System. The Applicants have also submitted these documents through their counsel's SharePoint site and will make these materials available on OPG's website at www.opg.com. An index of interrogatory responses included in this submission is provided in Attachment 1.

Consistent with the OEB's decision on permanent redactions dated May 1, 2026, the Applicants have also filed an updated confidential version of Ex. L-A2-Staff-016, Attachment 1, without permanent redactions.

Refusals

Pursuant to Procedural Order No. 2 (p. 5), Attachment 2 provides a table specifying which interrogatories the Applicants refused to respond to, and the reason for refusal.

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

Respectfully submitted,

Andrea Brown

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

Attachment 1 – Interrogatory Responses – Staff Expert IRs

Ex. L-A1-Staff-329

Ex. L-A1-Staff-330

Ex. L-A1-Staff-331

Ex. L-A1-Staff-332

Ex. L-A1-Staff-333

Ex. L-A1-Staff-334

Ex. L-A1-Staff-335

Ex. L-A1-Staff-336

Ex. L-A1-Staff-337

Ex. L-A1-Staff-338

Ex. L-A1-Staff-339

Ex. L-A1-Staff-340

Ex. L-A1-Staff-341

Ex. L-A1-Staff-342

Ex. L-A1-Staff-343

Ex. L-A1-Staff-344

Ex. L-A1-Staff-345

Ex. L-A1-Staff-346

Ex. L-A1-Staff-347

Ex. L-A1-Staff-348

Ex. L-A1-Staff-349

Ex. L-C1-Staff-350

Ex. L-C1-Staff-351

Ex. L-C1-Staff-352

Attachment 2
EB-2025-0297
Table 1 - Refusals – Board Staff Interrogatories (Expert Witness)

IR	Question	Response
A1-Staff-336	a) Isn't the volume of an energy distributor's deliveries just as import to its mission as the volume of a power generator's sales to its mission? b) Please confirm that the failure of an energy distributor to deliver is a closely monitored measure of its performance. c) Please explain any differences between power generation and energy distribution that might prompt LEI not to use delivery volume as the scale variable in an energy distribution productivity study.	*Response from London Economics International:* a) LEI understands the question asks about a gas distributor's volumes of energy delivery. LEI's work in the case of OPG is not related to gas distribution, and therefore, LEI does not believe this is relevant to understanding our TFP and benchmarking studies for OPG. b) See answer to part a. LEI has not presented any studies of "energy distributor… performance" in the current proceeding and therefore does not believe this is relevant to our independent benchmarking study of hydroelectric generation company performance. c) See answer to part a. LEI has not presented any studies of "energy distribution productivity" in the current proceeding and therefore does not believe this is relevant to our independent TFP study of the hydroelectric generation industry.
A1-Staff-337 d)	Please provide OPG's OM&A, capital, and total factor productivity trends.	*Response from London Economics International:* As discussed in response to Ex. L-A1-Staff-279 part b (and in part b of this response), LEI does not believe that analysis of a single firm's total factor productivity is relevant to the setting of the base productivity component of the X factor. For the purposes of setting the base productivity component of the X factor, a TFP study of the hydroelectric generation industry as a whole is appropriate, which is precisely the analysis that LEI provided in its TFP report.

Board Staff Interrogatory #329

Interrogatory

Ref 1: Exhibit L / A1-Staff-285
Ref 2: EB-2016-0152 / Exhibit L / Tab 11.1 / Schedule 1 Staff-247
Ref 3: Exhibit L / F1-AMPCO-099

Preamble:

In its response to Staff-247 in the EB-2016-0152 proceeding, OPG provided data on its operation, maintenance, and administrative ("OM&A") expenses for the 2002-2015 period.

Chart 3
Hydroelectric Operations, Maintenance, and Administration Costs ($M) (iv)

Years	Operations Cost, $M	Maintenance Cost, $M	Administration Cost, $M	Project OM&A, $M	Total Plant Group Costs, $M	HTO Central Support Group Cost, $M	Corp Allocated Costs, $M	Total Costs, $M
	A	B	C	(i) D	A+B +C	(ii) (v) E	(ii), (iii) F	A+B+C+E+F
2002	13.7	85.9	18.3	24.3	117.9	26.1	56.8	200.9
2003	14.8	96.7	19.2	30.1	130.7	19.1	58.1	207.8
2004	15.4	96.3	20.5	26.1	132.2	11.2	59.7	203.1
2005	15.4	106.0	21.0	30.1	142.4	15.8	65.4	223.6
2006	16.9	115.1	24.6	34.3	156.6	20.1	84.9	261.6
2007	17.5	123.2	24.3	33.4	165.0	19.8	94.7	279.4
2008	18.1	142.6	25.1	41.6	185.7	22.3	96.3	304.3
2009	20.4	133.9	30.8	33.5	185.1	28.5	85.2	298.8
2010	17.8	142.5	24.4	45.1	184.7	23.1	90.6	298.4
2011	17.6	129.0	28.0	28.4	174.6	24.4	93.5	292.5
2012	17.4	135.9	24.9	34.1	178.1	16.5	110.1	304.8
2013	19.2	138.7	24.7	34.6	182.6	17.2	111.1	310.9
2014	21.0	145.2	21.8	37.7	188.0	20.7	126.0	334.7
2015	21.2	161.7	27.3	52.3	210.2	32.2	140.0	382.4

Notes:
(i) Project OM&A is provided for information only. It is a subset of Maintenance Costs (Column B).
(ii) Classification between Operations, Maintenance, and Administration is not available for HTO Central Support Group and Corporate Allocated Costs.
(iii) Corporate Allocated Costs includes Corporate Support Services, Centrally Held Costs, and Asset Service Fees. IESO non-energy charges are excluded.
(iv) Includes data for currently regulated stations, as well as certain other stations for periods prior to becoming contracted or divested by OPG. First Nations provision funding amounts are excluded from Plant Group OM&A costs.

OPG provided more recent data on its OM&A expenses in response to A1-Staff-285.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
A1-Staff-285
Attachment 1

Numbers may not add due to rounding.

L-A1-Staff-285 - Attachment 1
OM&A - Regulated Hydroelectric
Total Hydroelectric Operation, Maintenance, and Administration (OM&A) 2016-2027 ($M)

Year	Operations Cost	Maintenance Cost	Administration Cost	Project OM&A [1]	Total Operating Region Costs	Support Costs [2]	Corporate Allocated Costs [2,3]	Total Costs
	(a)	(b)	(c)	(d)	(a)+(b)+(c)	(e)	(f)	(a)+(b)+(c)+(e)+(f)
2016	20.9	152.9	20.5	38.3	194.3	49.8	90.9	335.0
2017	21.4	159.3	17.6	42.2	198.3	52.0	72.5	322.8
2018	22.6	165.2	16.7	53.8	204.5	54.9	77.5	336.9
2019	21.5	164.8	16.8	54.3	203.1	54.6	78.3	335.9
2020	22.3	161.8	18.5	52.8	202.6	54.6	60.5	317.8
2021 [4]	23.2	183.1	17.2	71.6	223.5	53.5	76.9	353.9
2022	25.1	191.7	17.6	74.0	234.4	55.0	58.7	348.2
2023	27.7	207.3	18.1	75.1	253.0	58.6	43.8	355.4
2024	27.8	212.3	17.0	67.9	257.0	62.1	75.4	394.4
2025	30.5	215.1	16.9	71.9	262.5	65.4	72.5	400.4
2026 Budget	30.3	240.8	21.7	86.7	292.7	68.1	71.8	432.6
2027 Plan	31.8	281.3	23.3	123.3	336.5	73.1	83.1	492.7

Notes

1 Project OM&A is provided for information only. It is a subset of Maintenance Costs (column B). Project OM&A excludes costs associated with hydroelectric business development.

2 Support Group and Corporate Allocated Costs are not split between Operations, Maintenance, and Administration.

3 Corporate Allocated Costs includes Corporate Support Services, Centrally Held Costs, and Asset Service Fees. IESO non-energy charges are excluded.

4 2021 Project OM&A excludes provision of $9.5M in connection with a Final Settlement Agreement with a First Nation for shoreline erosion.

5 Operations, Maintenance, Administrative, and Total costs are comparable to pre 2016 levels. Support and Corporate allocations are not comparable due to organizational changes - refer to Ex. L-F1-AMPCO-099.

Question(s):

a) PEG wishes to undertake benchmarking and productivity calculations in years before 2016.

i. Are the older OM&A data still valid and comparable to what has been provided in response to A1-Staff-285? For this purpose, PEG is mainly concerned with the values in columns A-D. If not, please provide the same data requested in A1-Staff-285 for at least the 2010-2015 period. This will allow PEG to calculate 15-year productivity trends and benchmarking results for OPG.

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

ii. PEG understands that the pre-2016 data may not be fully comparable due to restructuring. However, PEG believes that the items that cause the inconsistency (e.g., support and corporate allocated costs) might be amenable to removal from cost, with the rest being consistent. If this is not the case, please explain what other inconsistencies exist and the impact on the OM&A expense data.

iii. Please provide an explanation or reference to a document that describes in more detail the types of cost included in Support Costs and Corporate Allocated Costs.

b) How does the definition of OM&A cost for OPG differ between the LEI TFP study and the LEI benchmarking study?

c) In response to part a subsection vii of A1-Staff-285, OPG indicated that about 60% of the OM&A cost for the hydroelectric operations is labor related. To make a fair comparison to US companies, PEG may wish to remove A&G, support, and corporate costs (i.e. columns C, E, and F) from OPG OM&A. This is 60% ratio also a reasonable value to use for the hydroelectric generation O&M (i.e., columns a and b of attachment 1)? If not, please provide an estimate that would be more reasonable for that part of cost.

d) To improve the comparability with US data, PEG wishes to know where non-salary labour costs are included in the data provided.

i. Which columns of Attachment 1 and Chart 3 from EB-2016-0152 Exhibit L, Tab 11.1, Schedule 1, Staff-247 include pension and benefit expenses?

ii. If pensions and benefit expenses are included in columns A and B of attachment 1 and chart 3, please provide the amounts for each year 2010-2025. Separate itemization for columns A and B is not necessary. If pensions and benefit expenses are in column C, please provide the amounts for 2010-2025.

iii. Where are payroll taxes included (if at all) in columns A-F of A1-Staff-285 Attachment 1 and chart 3?

iv. If any payroll taxes are in columns A-C of A1-Staff-285 Attachment 1, please provide the amounts for each year 2010-2025 for columns A+B and column C.

e) Please confirm that the data provided in A1-Staff-285 Attachment 1 and in Chart 3 from the response to Staff-247 in EB-2016-0152 exclude water for power or gross revenue charges. If not confirmed, please provide itemized water for power or gross revenue charges for each year of the 2010-2025 period.

f) In its response to F1-AMPCO-099, OPG objected to providing 2014 and 2015 data on OM&A costs, compensation and benefits details, and staffing information for the regulated hydroelectric business on the grounds that they were not comparable to more recent data due to changes in OPG's organization and cost structures. Please discuss these changes and explain their impact on OPG's cost reporting.

g) Please provide the approximate percentage of total hydroelectric property plant and equipment that is related to transformers used to step up voltage to transmission

voltage. Has the proportion significantly changed since 2010 and in which direction? If readily available, please provide the gross plant value associated with these assets or a similar group of transmission assets dedicated to hydroelectric operations from 2010-2025.

Response

The response to part b) was prepared by London Economics International ("LEI").

a)

i. The data in columns (a)-(d) and total OM&A are valid and comparable. Support and corporate allocated costs are not normalized for organization changes for pre-2016 data.

ii. Refer to a) i.

iii. Refer to the following (columns references as per Ex. L-A1-Staff-285, Attachment 1):

- Corporate Support Costs (column f): Ex. F3-1-1, Attachment 1
- Enterprise Support Costs (column e): Ex. F1-2-1, Attachment 1
- Centrally Held Costs (column f): Ex. F4-4-1.

b) LEI's TFP and benchmarking studies both used operations, maintenance, and administration costs for OPG, although the data sources differed – the TFP study relied on total OM&A data provided by OPG (as discussed in response to Ex. L-A1-Staff-279 parts c, d, and e), which was provided at the business unit level; the benchmarking study relied on OM&A data provided by EUCG (as discussed in response to Ex. L-A1-Staff-282 part g subpart iv), which was provided at the plant level.

c) Yes. It would be reasonable to use the estimated 60% labour ratio upon the removal of columns (c), (e), and (f).

d) OPG assumes "Attachment 1" in this question refers to Ex. L-A1-Staff-285, Attachment 1 in this Application, as there is no Attachment 1 in EB-2016-0152, Ex. L-11.1-Staff-247. Pension, benefits, and payroll taxes are embedded in all columns (a-f).

i. to iv. Refer to Chart 1 for the requested data for pension and benefits for the 2016-2027 period. Refer to Chart 2 for the requested data for payroll taxes for the 2016-2027 period. As noted in part f) below, OPG is unable to provide information prior to 2016.

Chart 1 – Pension & Benefits Components of Regulated Hydroelectric OM&A Expenses 2016-2027 ($M)

Year	Operations and Maintenance Costs ($M)	Administration Costs ($M)
2016	26.4	4.4
2017	25.3	4.7
2018	24.1	4.3
2019	24.5	4.3
2020	27.3	4.9
2021	28.5	4.6
2022	28.9	5.2
2023	28.5	4.7
2024	23.5	3.7
2025	27.9	4.3
2026 Budget	34.7	5.4
2027 Plan	35.8	5.6

Chart 2 – Payroll Tax Components of Regulated Hydroelectric OM&A Expenses 2016-2027 ($M)

Year	Operations and Maintenance Costs ($M)	Administration Costs ($M)
2016	4.7	0.8
2017	4.6	0.9
2018	4.4	0.8
2019	4.2	0.8
2020	4.1	0.7
2021	4.5	0.6
2022	4.8	0.7
2023	4.9	0.6
2024	6.2	0.8
2025	7.0	0.9
2026 Budget	7.8	1.1
2027 Plan	8.0	1.1

e) Confirmed. As noted in Ex. L-A1-Staff-285, part a) iv), gross revenue charges or other water rental agreements are not included.

f) OPG did not object to providing 2014-2015 OM&A data. Rather, as outlined in Ex. L-F1-AMPCO-099 and its submissions in EB-2024-0136, OPG is unable to normalize data prior to 2016 on a comparable basis to the rest of the Application to

account for the organizational changes, due to data availability constraints and the significant manual effort and assumptions that would be required to normalize historical information to account for these reorganizations, including allocations of operational support group costs. Therefore, while pre-2016 total OM&A data provided in Ex. L-A1-Staff-285 is comparable at the regulated hydroelectric level to subsequent years' OM&A data, OPG is unable to provide any meaningful further breakdown of costs.

Details on organizational changes can be found as follows:

- Renewable Generation business unit organizational changes since EB-2013-0321: Ex. F1-2-1, Attachment 1
- Normalization for organizational changes between EB-2016-0152 and EB-2020-0290: EB-2020-0290, Ex. A1-3-1, Attachment 1
- Normalization for organizational changes between EB-2020-0290 and EB-2025-0297: Ex. A1-4-1, Attachment 2

OPG has not prepared a summary of corporate and support organizational changes between EB-2013-0321 and EB-2016-0152.

g) OPG does not track hydroelectric step-up transformers and related assets as separate, stand-alone asset classes. OPG maintains an asset class titled "Hydro Electric – Main Power and Station Transformers (including installation)". This asset class includes the main output transformers but is not limited to those components and includes associated station service transformers. This asset class represents approximately 2.5% of total regulated hydroelectric net property, plant, and equipment, and has remained consistent at this level over the period 2010-2025.

Board Staff Interrogatory #330

Interrogatory

Ref 1: Exhibit L / A1-Staff-285
Ref 2: Ontario Regulation 395/11

Preamble:

In this response, OPG provides data that other parties can use to appraise its cost performance. In part a) iv. of this response OPG states that "OM&A and Total costs are comparable to pre-2016 amounts. Support Group and Corporate Allocated costs are not comparable to pre-2016 amounts due to organizational changes."

Question(s):

a) In part a) i. of its response to A1-Staff-285, OPG provides the 2016-2025 values of gross additions to hydroelectric plant. Please confirm that OPG believes that the 2016-2025 plant additions are consistent with those provided in EB-2016-0152.
b) Please discuss any changes in capitalization policy that would affect the capitalization of overheads in the years since 2020. Do any such changes on balance result in more or less overheads being capitalized?
c) Ontario Regulation 395/11 required OPG to prepare its financial statements in accordance with US generally accepted accounting principles ("GAAP") for all financial years beginning on or after January 1, 2012. Please discuss the impact on the reported OM&A expense and plant data of this switch in accounting standards.

Response

a) Confirmed.

b) There have been no changes to OPG's capitalization policy since 2020 that would affect the capitalization of overheads. For clarity, as stated at Ex. D4-1-1, p. 1, "overhead costs that are only directly attributable to the acquisition or construction of a capital asset are capitalized."

c) OPG's transition from Canadian GAAP to US GAAP effective January 1, 2011 did not have a material impact on the reporting of OM&A expenses for the regulated hydroelectric facilities. As described in EB-2012-0002, Ex. A3-1-2, Section 4.1, the driver of such impacts was a difference in the required treatment of long-term disability plan costs. As shown in EB-2012-0002, Ex. H1-1-2, Table 6, lines 4 and

7, col. (a), the annual change in the regulated hydroelectric facilities OM&A costs was less than $0.5M annually.

Board Staff Interrogatory #331

Interrogatory

Ref 1: Exhibit L / A1-Staff-004
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / pp. 11, 18-19

Preamble:

In its response to A1-Staff-004 OPG provided its calculation of the 2027 Inflation Factor based on actual data from Statistics Canada. The 2027 inflation factor value was 2.9% based on actual inflation. In its application, OPG assumed that the 2027 inflation factor would be 3.49%.

Question(s):

a) Is OPG proposing to change its C-Factor proposal to reflect the change in the value of the 2027 Inflation Factor and other new developments?
b) Please update the C factor to reflect the revised Inflation Factor and any other new developments, such as those that have arisen from other interrogatory responses or evidence updates.

Response

a) OPG is proposing to change its proposed C-factor and GRCF to reflect the 2027 inflation parameters and part of the payment amounts order process. OPG is unaware of "other new developments" at this time. For clarity, as indicated in Ex. C1-1-1, Section 3.0, the Application proposes to update the ROE for the IR term using the prevailing ROE specified by the OEB in accordance with the OEB's EB-2024-0063 decision as of the effective date of the Payment Amounts Order in this proceeding (the OEB typically sets its cost of capital parameters in October of each year).

b) See Attachment 1, Tables 1 and 2 for updated C-factor and GRCF calculations based on the revised inflation factor per Ex. L-A1-Staff-004.

Numbers may not add due to rounding.

Filed: 2026-05-15
EB-2025-0297
Exhibit L
A1-Staff-331
Attachment 1
Table 1

Table 1
Payment Amounts and Riders – Regulated Hydroelectric Facilities - Revised Inflation Factor
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027	Illustrative Payment Amounts[1] 2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Price Escalator (I-Factor)**	2	**2.94%**	**2.94%**	**2.94%**	**2.94%**	**2.94%**
2	Labour: Average Weekly Earnings - Ontario	2	3.58%	3.58%	3.58%	3.58%	3.58%
3	Non-Labour: Canadian Gross Domestic Product Implicit Price Index - Final Domestic Demand	2	2.83%	2.83%	2.83%	2.83%	2.83%
4	**Productivity Factor**	3	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
5	**Stretch Factor**	4	**0.15%**	**0.15%**	**0.15%**	**0.15%**	**0.15%**
6	**"I-X"** (line 1 - line 4 - line 5)		**2.79%**	**2.79%**	**2.79%**	**2.79%**	**2.79%**
7	**Custom Capital Factor** (Attachment 1, Table 2, line 10)	5		**4.62%**	**5.33%**	**2.36%**	**1.10%**
8	**GRC Adjustment** (Attachment 1, Table 2, Note 3, line 3c)	6		**-0.59%**	**-0.55%**	**-0.51%**	**-0.49%**
9	**Price Cap Index**			**6.82%**	**7.57%**	**4.63%**	**3.40%**
10	**Prior Year Hydroelectric Payment Amount ($/MWh)**			51.39	54.90	59.05	61.79
11	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	7	51.39	54.90	59.05	61.79	63.89
12	**Hydroelectric Payment Rider ($/MWh)**	8	(1.17)	(1.17)	(1.17)	0.00	0.00
13	**Total of Hydroelectric Payment Amounts Plus Riders** (line 11 + line 12)		50.22	53.73	57.88	61.79	63.89

Notes:

1 Payment amounts for 2028-2031 are illustrative only - final payment amounts to be determined annually using I-factor values.

2 2027 inflation factor per inflation parameters estimated in Ex. L-A1-Staff-004, and weightings per Ex. A1-3-2 Chart 3: 15.3% labour cost (line 4), 9.3% non-labour cost (line 2) and 75.4% capital cost (line 1).

3 Per Ex. A1-3-2, Section 2.3.2.1.

4 Per Ex. A1-3-2, Section 2.3.2.2.

5 Per Ex. A1-3-2, Section 2.3.3. Revised to reflect updated inflation factor per Ex. L-A1-Staff-004.

6 Per Ex. A1-3-2, Section 2.3.4. Revised to reflect updated inflation factor per Ex. L-A1-Staff-004.

7 2027 is cost of service amount. Subsequent years escalated by the Price Cap Index (line 9).

8 Per Ex. H1-2-1, Table 1, line 21.

Numbers may not add due to rounding.

Filed: 2026-05-15
EB-2025-0297
Exhibit L
A1-Staff-331
Attachment 1
Table 2

Table 2
Calculation of Capital Factor for Regulated Hydroelectric Facilities - Revised Inflation Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation**	Ex. F4-1-1 Table 1, line 10	215.4	228.4	249.6	263.6	271.7
2	**Cost of Debt**	Note 2	201.5	222.3	254.3	272.9	286.9
3	**Return on Equity**	Note 2	432.8	458.9	512.3	543.4	568.8
4	**Income Taxes**	Ex. F4-2-1 Table 3b, line 24	27.3	70.3	87.6	101.6	110.7
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	876.9	979.9	1,103.8	1,181.5	1,238.1
6	**Regulated Hydroelectric Stretch Factor Capital Related Revenue Requirement Adjustment**	0.15% * line 5 (cumulative)		1.5	3.1	4.9	6.8
7	**Capital Related Revenue Requirement after Stretch**	line 5 - line 6	876.9	978.5	1,100.7	1,176.6	1,231.4
8	**Capital Afforded through (I-X) Adjustment** (assuming Custom Capital Factor in preceding years)	(line 8_{t-1} + line 9_{t-1}) x (I-X)	876.9	901.4	1,005.8	1,131.4	1,209.4
9	**Capital Related Revenue Requirement Shortfall**	line 7 - line 8	-	77.0	94.9	45.1	22.0
10	**Custom Capital Factor (C-Factor)**	line 9_t / line 14_{t-1}		4.6%	5.3%	2.4%	1.1%
11	**OM&A (excluding GRC)**	2028-2031: escalated by (I - X)	501.4	515.4	529.8	544.6	559.8
12	**GRC**	Note 3	352.2	352.2	352.2	352.2	352.2
13	**Other Revenues**	2028-2031: escalated by (I - X)	(62.2)	(64.0)	(65.8)	(67.6)	(69.5)
14	**Total Revenue Requirement**	line 7 + (lines 11 to 13)	1,668.3	1,782.1	1,917.0	2,005.8	2,073.9

Notes:

1 Per Ex. I1-1-1, Table 1.

2 Determination of cost of capital amounts included in the C-factor is based on the following:

Line No.	Description	Reference	2027	2028	2029	2030	2031
2a	Rate Base	Ex. B1-1-1, Table 1	9,135.1	9,687.1	10,814.1	11,471.1	12,007.4
2b	Short-Term Debt	Ex. C1-1-1 Tables 1-5	7.7	7.3	8.0	7.8	6.7
2c	Long-Term Debt	Ex. C1-1-1 Tables 1-5	193.8	215.1	246.3	265.1	280.2
2d	Common Equity	Ex. C1-1-1 Tables 1-5	432.8	458.9	512.3	543.4	568.8

3 The GRC Factor calculated below effectively fixes the underlying GRC amount recovered through payment amounts at the 2027 amount:

Line No.	Description	Reference	2027	2028	2029	2030	2031
3a	GRC Escalated by (I-X)	line 12 x (1+(I-X))	352.2	362.0	362.0	362.0	362.0
3b	Variance to Fixed GRC	line 12 less line 3a	-	(9.8)	(9.8)	(9.8)	(9.8)
3c	Variance as Percentage of Prior Year Revenue Requirement	line 3b, col. b / line 14, col. a	-	(0.6)%	(0.6)%	(0.5)%	(0.5)%

Board Staff Interrogatory #332

Interrogatory

Ref 1: Exhibit L / A1-CCC-006
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1 / pp. 10, 16
Ref 3: EB-2025-0252 / Exhibit 1 / Tab 11 / Schedule 2 / pp. 11-12
Ref 4: EB-2025-0312 / Exhibit 1 / Tab 5 / Schedule 1 / p. 13

Preamble:

In the cited interrogatory, OPG was asked to provide the labour and non-labour weightings for an inflation factor based on OPG-specific data rather than an industry average. LEI responded that calculating an inflation factor based on OPG-specific data "would not be appropriate" as the inflation factor "should be exogenous to the utility." LEI further said that "use of industry weights ensures an exogenous inflation factor that is representative of industry conditions and will provide incentives to the regulated firm consistent with the theoretical underpinnings of incentive ratemaking and an index based formula."

Question(s):

a) Two Ontario electricity distributors (Alectra and Elexicon) are currently requesting approval of input price differentials based on the difference between the share of labor expenses in OM&A and total cost.
   i. Please confirm that these calculations are based on company-specific cost shares.
   ii. Does LEI believe that these proposals would result in input price differentials that are insufficiently exogenous?
   iii. Please also discuss if LEI believes that such adjustments are "consistent with the theoretical underpinnings of incentive ratemaking and an index-based formula.
b) Does LEI believe that using a non-transparent data source such as EUCG to support its inflation factor calculations meets all of its criteria for inflation factor design?
   i. If yes, please explain your rationale.
   ii. If no, please identify which criteria are missed and explain your rationale.
c) Please provide the share of labor in OPG's total cost and OM&A expenses so that parties can better ascertain whether the use of industry cost shares, some of which are drawn from a non-transparent data source, unduly favor the Company.
d) Please provide the calculations that support LEI's proposed weights of 15.3% for labour inflation, 9.3% for non-labour inflation, and 75.4% for capital inflation.

Response

The responses to parts a), b) and d) were prepared by London Economics International ("LEI").

a)
i. to iii.
LEI is not active in those two rate cases and thus has not had sufficient time to study or comment on what is being considered in those rate cases.

b) LEI would not label EUCG as a "non-transparent data source" – it is simply not public. We also note that in the prior proceeding, we used EUCG data to determine the industry labour versus non-labour shares as part of our recommended weighting for the inflation factor (as indicated in slide 7 of LEI's inflation factor report), consistent with the approach used in this proceeding. In its EB-2016-0152 Decision and Order dated December 28, 2017, the OEB "accept[ed] the indices and weightings as proposed." (p. 122)

c) Total regulated hydroelectric compensation costs (as described in Ex. F4-3-1, Attachment 1, p. 3, line 33) as a proportion of total regulated hydroelectric costs (as described in Ex. F1-1-1, Table 1 and Ex. D1-1-1, Table 1) averages approximately 40% over the 2016-2024 period.

Refer to Ex. L-A1-Staff-285 a) vii for the share of labour in regulated hydroelectric OM&A.

d) See the "I-factor weights" tab in the attached "L-A1-Staff-332_Attachment 1" file. LEI notes that varying the weights generally had a very small impact on the composite value of the inflation factor (less than 0.1%).

Board Staff Interrogatory #333

Interrogatory

Ref 1: Exhibit L / A1-CCC-008

Preamble:

In A1-CCC-008 part f, OPG refused to provide the percentage of sustaining capital investments as a percentage of the Company's own total hydroelectric capital investments for each year of the study period on the grounds that this data was subject to a non-disclosure agreement.

Question(s):

a) Are the data OPG provided to EUCG confidential for the purposes of this proceeding? If yes, why is this the case? If no, please provide the percentage of sustaining capital investments as a percentage of OPG's total hydroelectric capital investments for each year of the benchmarking sample period.

Response

a) OPG assumes "the benchmarking sample period" to be 2020-2023, as per Ex. L-A1-CCC-008, Reference 1.

The data provided to EUCG by OPG and other member utilities is confidential and subject to anti-trust and confidentiality requirements. All data submissions are blinded. LEI worked directly with EUCG under a non-disclosure agreement for the purpose of benchmarking. The data submitted to EUCG by OPG includes all hydroelectric stations, both regulated and non-regulated.

Chart 1 below details the proportion of regulated sustaining hydroelectric capital as a percentage of total regulated capital.

Chart 1 – Sustaining Capital 2020-2023 (% of total Regulated Hydroelectric Capital Investment)

Prescribed Facility Category	**2020**	**2021**	**2022**	**2023**
Sustaining Capital[1] ($M)	212.2	264.3	212.1	324.9
Total Regulated Hydroelectric Capital[2] ($M)	287.9	386.5	313.5	369.7
% of Total Capital	**74%**	**68%**	**68%**	**88%**

Notes:
1. As per Ex. D1-1-1, Table 3, line 2.
2. As per Ex. D1-1-1, Table 3, line 4.

Board Staff Interrogatory #334

Interrogatory

Ref 1: Exhibit L / A1-EP-003
Ref 2: Exhibit A2 / Tab 2 / Schedule 1 / Attachment 1 / p. 37
Ref 3: Exhibit I1 / Tab 2 / Schedule 1 / p. 1
Ref 4: EB-2025-0252, Exhibit 1 / Tab 11, Schedule 2, pp. 8-15

Preamble:

In response to part b of this question, OPG said that a "typical price cap framework cannot fund capital investment when the capital related revenue provided through annual (I-X) adjustments is less than the forecast capital-related revenue requirement over the period."

OPG did not fully respond to parts c and d of Ref 1.

Ref 2 shows that OPG forecasts its hydroelectric generation to grow by roughly 400,000 MWh excluding surplus baseload generation losses during the term of the Custom IR plan.

Question(s):

a) Does OPG believe that the growth in volumes does not provide funding for capital under a price cap framework? Please explain your answer.
b) Please confirm that the growth in OPG's forecasted volumes during the Custom IR plan term will lead to increased reviews in each year of the 2028-2031 period relative to 2027. For example, at OPG's requested 2027 Hydroelectric Payment Amount ($51.39/MWh) volume growth will lead OPG to receive an additional $20,556,000 in revenues during the final year of the Custom IR plan term over the test year level. If not confirmed, please explain why this value is not confirmed and provide the correct amount for 2031 using OPG's proposed 2027 Hydroelectric Payment Amount.
    i. Please discuss where, if at all, this increase in OPG's revenue from volume growth is considered in the proposed attrition relief mechanism.
c) In its CIR proposal in EB-2025-0252, Alectra Utilities considers future growth in billing determinants in the design of its proposed price cap index. Why is an adjustment of this kind not appropriate in the price cap index of OPG?

Response

OPG disagrees with the assertion in the preamble that OPG did not fully respond to parts c) and d) of Ex. L-A1-EP-003.

a) To the extent the increase in revenue from increased volumes is greater than the increase in any associated costs incurred to generate such volumes (i.e., increase in net revenue), OPG believes that the increase in net revenue can be used to fund capital investment.

b) In terms of revenues, OPG confirms that the difference between 2027 and 2031 production shown in Ex. A2-2-1, Attachment 1, p. 37 multiplied by $51.39/MWh is equal to approximately $20.6M. The increase in net revenue associated with this production increase is approximately $18.0M, which is net of GRC.[1]

   i. Refer to Ex. L-A1-SEC-011.

c) Refer to Ex. L-A1-SEC-011.

[1] See Ex. L-A1-SEC-012, Attachment 1, Table 6 for a forecast of GRC expense for the 2027-2031 period.

Board Staff Interrogatory #335

Interrogatory

Ref 1: Exhibit L / A1-Staff-279

Preamble:

In part e of this response LEI states:

> However, we requested that OPG provide its OM&A data in a manner consistent with the FERC Form 1 accounts listed above in response to part (d) of this IR. LEI also compared the updated data provided by OPG (i.e., for the 2015-2023 period) to the prior data received and used in LEI's 2016 TFP Study (for the 2002-2014 period) to check for anomalies and alignment across the entire study timeframe.

Question(s):

a) Were any anomalies found in OPG's data? If so, what adjustments did LEI make to the data to account for these anomalies?

Response

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

a) There were no anomalies between the data used in LEI's study filed at Ex. A1-3-2, Attachment 2 and LEI's 2016 TFP Study. Therefore, LEI did not make any adjustments to the total OM&A data provided by OPG.

Board Staff Interrogatory #336

Interrogatory

Ref 1: Exhibit L / A1-Staff-278

Preamble:

In part b of its response, LEI explains that generation MWh is the "measure of output" for their TFP study and seem to specifically not consider it to be a scale variable. LEI goes on to describe the use of MW capacity in the econometric model, adding that "LEI understands that EUCG also controls for plant capacity (not generation) in its benchmarking analysis to reflect economies of scale in costs."

In part d, LEI confirms that it recently used customers as the output metric in a gas distribution TFP study and go on to state that that choice is not applicable to OPG because hydro generation and gas distribution are "entirely different business[es]."

Question(s):

a) Isn't the volume of an energy distributor's deliveries just as import to its mission as the volume of a power generator's sales to its mission?
b) Please confirm that the failure of an energy distributor to deliver is a closely monitored measure of its performance.
c) Please explain any differences between power generation and energy distribution that might prompt LEI not to use delivery volume as the scale variable in an energy distribution productivity study.

Response

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

a) LEI understands the question asks about a gas distributor's volumes of energy delivery. LEI's work in the case of OPG is not related to gas distribution, and therefore, LEI does not believe this is relevant to understanding our TFP and benchmarking studies for OPG.

b) See answer to part a. LEI has not presented any studies of "energy distributor… performance" in the current proceeding and therefore does not believe this is relevant to our independent benchmarking study of hydroelectric generation company performance.

c) See answer to part a. LEI has not presented any studies of “energy distribution productivity” in the current proceeding and therefore does not believe this is relevant to our independent TFP study of the hydroelectric generation industry.

Board Staff Interrogatory #337

Interrogatory

Ref 1: Exhibit L / A1-Staff-279

Preamble:

In part b of its response, LEI refuses to provide a table with productivity calculations for OPG.

In part c, LEI clarifies that OPG's administrative costs are included in their cost definition while those costs are not included in LEI's cost definition for the U.S. companies, and state that the amounts are "not sizeable."

In part f, LEI states that they use the Ontario AWE for all employees for labour prices because that is the measure used by the OEB in the past.

Question(s):

a) In subpart ii of their response to part a, LEI does not answer the question asked, perhaps misunderstanding the reference intended.
   i. In the text surrounding Figures 33 and 34, LEI says it produce similar findings to it's 2016 study's reported -1.18% TFP for the 2002-2014 period. The numbers presented in the current study and the supporting text both say and show that productivity after adding the 2015-2023 period is "higher" and "less negative." Please confirm that this would in fact be "more rapid" productivity.
   ii. Did LEI reproduce the 2002-2014 trends with this dataset, and were they consistent as is implied in the text? If not, please report these updated TFP estimates for that time period.
b) Does LEI believe their TFP calculations are not valid for individual distributors[1] and for OPG specifically? If so, please explain why.
c) Aren't the OM&A, capital, and total factor productivity trends of OPG useful for gauging the relevance of LEI's productivity trend research to the Company's productivity factor?
d) Please provide OPG's OM&A, capital, and total factor productivity trends.
e) Regardless of which wage rate index the OEB uses, which index does LEI believe is more accurate and appropriate for benchmarking and productivity trend research and why.

[1] Please note that there was and is no suggestion that individual firm productivity be used as a substitute for industry productivity measurement.

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

Response

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

a) LEI did answer the question asked in Ex. L-A1-Staff-279 part a, subpart ii. The question asked: "Why is LEI opting for a much longer TFP trend now?", to which LEI responded: "LEI used the longest timeframe allowed by the availability of data in both the 2016 TFP Study as well as the current study."

i. LEI's TFP results for the 2002-2023 period in the current study of -0.40% (under the physical approach) and -1.01% (under the monetary approach) are both indeed higher and less negative than the -1.18% TFP growth rate reported in LEI's 2016 TFP study for the 2002-2014 period. LEI does not agree with the use of "more rapid" in this context as this wording does not specify a particular direction; LEI chose to use clearer language that would indicate the relative direction (higher or lower) of the new study results compared to the 2016 TFP study results.

ii. LEI reproduced the 2002-2014 TFP trend using the current dataset and confirmed that the TFP results are consistent with those reported in LEI's 2016 TFP Study when restricting the peer group to the same 16 utilities used in the 2016 study. However, when the TFP analysis is conducted using the expanded peer group of 21 utilities from the current study (including the addition of Duke Energy Progress, Lockhart Power Company, NYSEG, Chelan, and WAPA), the broader industry sample yields different TFP estimates for the 2002-2014 period. The TFP estimates for 2002-2014 under both peer group specifications are presented in the table below. Notably, even though the numerical values are different, the general direction of the TFP results is the same (i.e., negative TFP).

	Average TFP growth (2002-2014)	Trend regression TFP growth rate (2002-2014)
2002-2014 (16 peers used in LEI's 2016 TFP Study)	-1.01%	-1.18%
2002-2014 (21 peers used in current study)	-0.75%	-0.61%

b) TFP trend calculations for a specific firm are not relevant for purposes of setting the base productivity component of the X factor, which should instead be based on an industry TFP study. This is true for any TFP trend calculation that may be done for one company, because the theoretical underpinnings of using empirical analysis of TFP trends presume that the X factor is set in consideration of the industry trend.

c) See answer to part b).

d) As discussed in response to Ex. L-A1-Staff-279 part b (and in part b of this response), LEI does not believe that analysis of a single firm's total factor productivity is relevant to the setting of the base productivity component of the X factor. For the purposes of setting the base productivity component of the X factor, a TFP study of the hydroelectric generation industry as a whole is appropriate, which is precisely the analysis that LEI provided in its TFP report.

e) For the sake of consistency, LEI used Statistics Canada's AWE index as the measure of labour cost inflation across all of its analyses for this proceeding – including the TFP study, benchmarking study, and inflation factor analysis. LEI believes the AWE index is an appropriate measure of labour cost inflation for several reasons, including source reliability (Statistics Canada has not changed the AWE methodology for many years, since 2001), data availability, exogeneity, index stability, and precedence and simplicity (use of AWE as a labour price sub index has been approved by multiple regulators, including the OEB and BCUC), as stated on slide 22 of LEI's inflation factor report.

Board Staff Interrogatory #338

Interrogatory

Ref 1: Exhibit L / A1-Staff-282

Preamble:

In part a of their response, LEI confirms that they set all index values to 1.00 in 2013 as an "anchor value," and that the index values otherwise vary by year and country, and also by region for the ECI.

In parts c and d, LEI responds to a question about trends in cost efficiency in the econometric model and explains that benchmarking OPG's forecasted costs would be inappropriate. They claim their benchmarking model measures OPG's "relative efficiency" by comparing the firm to the "industry average" and assessing the gap between the two.

In part g, subparts i, ii, and iii LEI responds to questions about OPG's observations in the econometric model data.

Question(s):

a) In part a, LEI confirms that the *growth* rates of the indexes vary by year and country, and additionally by region in the case of the ECI, but the answer does not indicate whether index *levels* at any point in time were adjusted by region. Please confirm that any differences in the input price index values of sampled U.S. distributors are due solely to differences in measured inflation.
b) Please confirm that the econometric models use panel data which, by definition, cause the estimates of the model standard errors exhibit heteroskedasticity, sever serial correlation, and spatial correlation. If confirmed, please explain why the non-robust p-value has any meaning at all.
c) Please confirm that there are well-established approaches to benchmarking that can measure the change in a company's cost efficiency over time and the efficiency inherent in cost forecasts.
d) Please clarify whether LEI claims that OPG's portion of the observations used to estimate the model does not affect the model parameters and the efficiency rankings which result.

Response

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

a) LEI did not present a study of "U.S. distributors" as implied in the wording of the question; LEI assumes this is a typographical error. For LEI's total cost benchmarking study of hydroelectric generation companies, the values in column I of the "US Price Indices" tab and columns S, T, and U of the "CA Price Indices" tab in the "Benchmarking Workpapers_Redacted" file are related to reported inflation index values, which vary over time and whether a specific hydroelectric operator is a US or Canadian entity.

b) LEI's econometric study employs a panel regression. However, panel data does not necessarily exhibit heteroskedasticity, serial correlation, and spatial correlation in all cases as suggested in the question. The presence of these issues depends on the specific combination of data being used for the analysis. For the models presented in LEI's analysis, randomness is indeed observed in the residuals against the fitted values, as demonstrated in Figure 1 (for the OM&A model) and Figure 2 (for the OM&A + SC model) below.

Figure 1: Residuals vs Fitted values - OM&A model

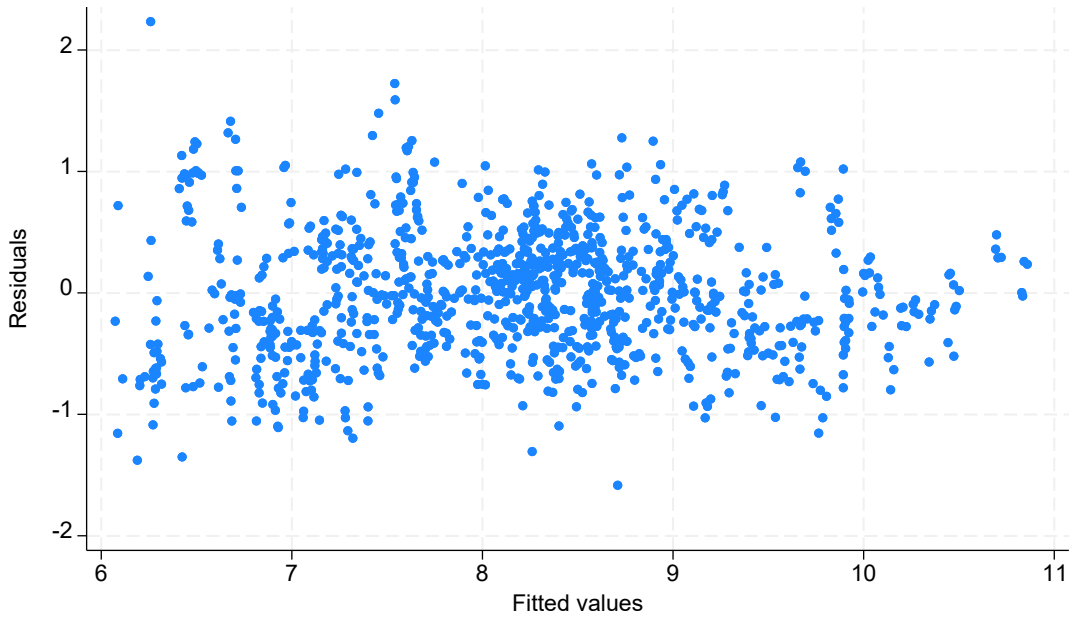
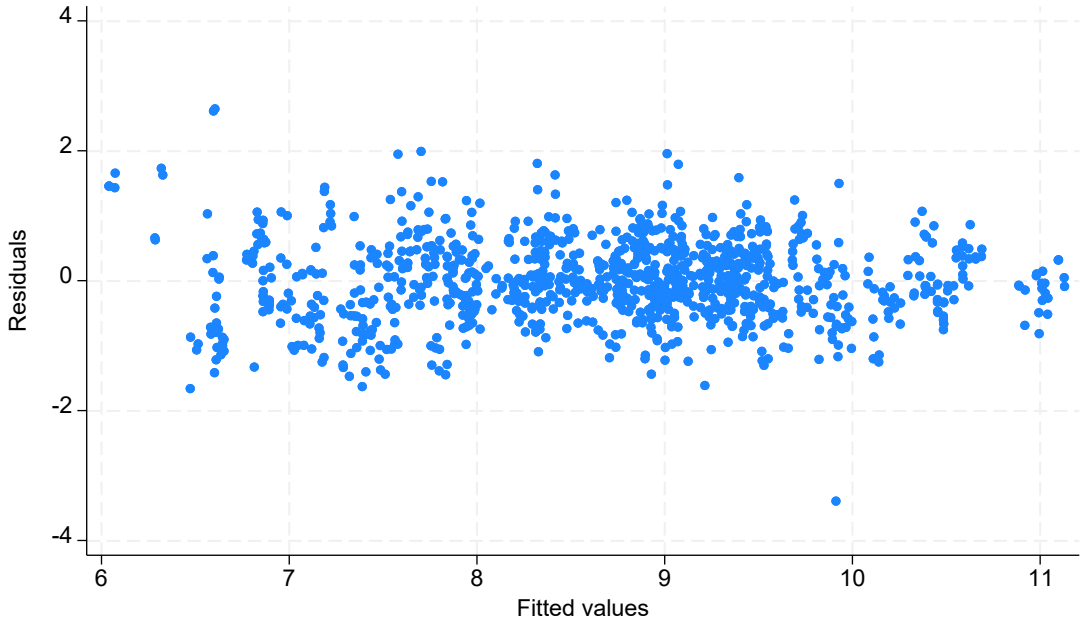


Figure 2: Residuals vs Fitted values - OM&A+SC model



For datasets that do present heteroskedasticity, there are well recognized methods for minimizing or eliminating such issues, such as substituting or transforming variables, and the use of robust inference techniques.

LEI has carried out alternative testing for both the OM&A and OM&A + SC models to control for such potential data issues and can confirm that there are no material impacts to the level of statistical significance and standard errors presented. Therefore, the "issues" that are itemized in the question are not undermining LEI's models, and as a result, the conclusions presented in LEI's benchmarking report remain valid.

c) Econometric analysis is a diverse and wide field of data analysis. There are various econometric methods for forecasting and consideration of forecasts. This observation does not modify or invalidate other responses to interrogatories that LEI has provided.

d) As discussed in response to Ex. L-A1-Staff-282 part g), the fixed effects specification captures the impact of a hydroelectric power plant from being owned by one entity versus another, while controlling for other drivers of cost. LEI further confirms that OPG's fixed effects variable is assigned to 20% of the observations in the plant-level dataset. It is notable that there is one other hydroelectric operator that also accounts for a similar proportion of the panel dataset.

In setting up the benchmarking analysis, LEI has ensured that there is a balanced panel, in that each plant is represented in each year of the 4-year study timeframe. In addition, the range of plants by size, number of units, and proportion of staffed control rooms for OPG overlaps with other hydroelectric operators in the panel dataset.

Based on the data for the benchmarking study and the tests that LEI has conducted, we confirm that OPG's relative size of the fleet does not introduce biases that would materially impact the robustness of the models or change our benchmarking conclusions.

Board Staff Interrogatory #339

Interrogatory

Ref 1: Exhibit L / A1-Staff-284

Preamble:

Regarding Ref 1, in part a of its response, LEI states the OM&A price variable is negative but not statistically significant. In part b they state the OM&A price variable is not significant in either model and should thus be interpreted as not different from zero. In part c, LEI confirms they did not log the price index variables. In part d) LEI evaluates the trend variable coefficients using the p-values, and states the magnitude of the trend variable should thus be interpreted as not different from zero. In part e) they discourage using the result for any productivity application.

Ref 2 pertains to LEI's econometric model sample and assumptions.

Question(s):

a) To clarify, is LEI claiming that they have demonstrated empirically that there was no relationship between OM&A costs and OM&A prices for the 2020-2023 period for this sample?
b) Did LEI test a model with logged price variables? If so, were the results more plausible?

Response

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

a) As stated in LEI's benchmarking report, the timeframe covered by LEI's analysis is relatively short (covering the four-year period from 2020-2023), resulting in limited observed variation in the OM&A price index over the study period. Due to this limited variation, a statistically significant relationship between the OM&A price index and OM&A costs was not observed, given the other independent variables and interactions with the fixed effects variables.

b) No, LEI did not test a model with logged price variables. Given that the OM&A price index did not demonstrate significant variation (as discussed in part a), there were no outliers that would necessitate taking the natural log of the variable.

Board Staff Interrogatory #340

Interrogatory

Ref 1: Exhibit L / A1-Staff-286

Preamble:

In subpart i of part a, LEI provides a sizeable list of other available variables, stating that they "generally found that they were not statistically significant" and were excluded on this basis. In subpart ii, LEI does not answer the specific question about testing a generation volume variable but instead points to the previous general answer.

Question(s):

a) While we understand LEI's characterization of the "general" performance of these other variables, please clarify whether any of these variables or combinations of variables tested were found to be statistically significant? Please report their reason for exclusion form the featured model.
b) Which variables were not considered in econometric runs?
c) Please confirm that by this response, LEI intends to specifically communicate that generation volume was tested in both models and was found to be statistically insignificant in both.
d) Please confirm LEI's testing was all done with the same non-robust estimation methods as used in their featured models.

Response

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

a) LEI did not save those preliminary calibration runs and therefore cannot report specific results. LEI notes that correlation was observed between some of the variables tested, and as such we were mindful of multi-collinearity. LEI believes that the final OM&A and OM&A + SC models presented in the benchmarking report provide a robust fit for the purposes of the analysis.

b) See response to part a).

c) No, that is not the intent of any of LEI's responses. Generation was likely tested in lieu of capacity to consider economies of scale. The decision to use capacity in lieu

of generation was not simply because of statistical significance. LEI also considered overall model fit balanced against complexity and economic intuition.

d) LEI did run other estimation methods but given that we did not save the initial test runs, we cannot provide those workpapers.

Board Staff Interrogatory #341

Interrogatory

Ref 1: Exhibit L / A1-Staff-288

Preamble:

In subpart i of part a, LEI responds that they "used the capacity as reported in the EUCG database" in the econometric model while also excluding the capital investments related to that capacity from the econometric sustaining capital cost definition. In subpart ii LEI states they do not use the Handy-Whitman indexes in their capital price, citing the need for "sufficient variability" in the model, a challenge which is fulfilled by their chosen capital price.

Question(s):

a) Please confirm our understanding: does this mean that LEI uses the total capacity in MW as a scale variable in the econometric model, but excludes the capital costs associated with improvements to and expansion of that existing capacity?
b) How many of the 6 Handy Whitman regions do the sampled utilities fall into?
c) Why could LEI not use regional Handy Whitman indexes and make an adjustment for US vs. Canada prices? Does LEI believe doing so could introduce more variation and more accuracy into the data compared to their chosen methodology?

Response

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

a) LEI confirms that MW was used as a scale variable in both models (OM&A and OM&A + SC). As explained on page 6 of LEI's benchmarking report, we focused on capital expenditures for sustaining capability, which as defined by EUCG are driven by the need to maintain existing assets in good running condition. They usually include equipment replacement and may or may not include technological improvements that extend equipment useful life. As further explained in LEI's benchmarking report, we excluded capital investments associated with improvements and additions to plant generation capacity, as these "depend on where a company is within its broader investment cycle, occur irregularly, and are typically large in terms of dollars spent. Including these costs in an econometric analysis over a timeframe of four years could distort comparisons, given that not all companies would have faced similar capacity-improvement capital spending during the study period."

b) The utilities included in LEI's TFP industry sample fall into 5 of the 6 regions covered by the Handy Whitman Cost Index for Hydraulic Production Plant. LEI has not mapped the peers included in the benchmarking analysis to the Handy Whitman regions.

c) As explained in response to Ex. L-A1-Staff-288 part a) subpart iii:

> *"within a cross-sectional panel dataset such as the dataset used in LEI's benchmarking analysis, sufficient variability in the data is key to a robust model. Therefore, LEI chose to use US GDP-PI and Canadian GDP-IPI FDD as proxy measures for the price of capital – this allowed for consistent measurement across both US and Canadian entities, while also allowing for differentiation at the national level. Handy Whitman indices would not allow for the same differentiation between US and Canada."*

LEI believes that using official indices from the US BEA (GDP-PI) and Statistics Canada (GDP-IPI FDD) – which do not require adjustments – was a better approach than using Handy Whitman Indexes (which as the question acknowledges, would have required adjustments) for the purposes of the timeframe and cross-sectional data used in LEI's benchmarking study.

Board Staff Interrogatory #342

Interrogatory

Ref 1: Exhibit L / A1-Staff-291
Ref 2: Exhibit L / A1 Staff-282
Ref 3: Exhibit L / A1 Staff-288, part a)

Preamble:

In its response to part c of Ref 1 LEI and the Applicants state their belief that the econometric benchmarking "total cost" model proves OPG is a top quintile cost performer relative to its peers, and that this result should be used to decide the Applicant's stretch factor for several applications.

Question(s):

a) Is LEI's assessment dependent on the assumption that OPG's performance does not measurably affect the model parameters used to benchmark OPG's performance? Please explain.

Response

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

a) No, LEI's analysis is not making such an assumption. OPG's performance is included alongside the performance of other peers in establishing the "average" for the industry, against which OPG and other peers are then evaluated.

Board Staff Interrogatory #343

Interrogatory

Ref 1: Exhibit L / A2-CCC-015

Preamble:

OPG's internal analysis was informed by an independent view of construction cost escalation by Kroll Canada Ltd.

Question(s):

a) Did OPG or Kroll consider the econometric forecasts of electric utility construction cost trends that are available from S&P Global's Power Planner service?
b) If yes, what were the results?
c) Did Kroll provide econometric construction cost inflation forecasts or instead base its analysis chiefly on the recent rapid construction cost inflation and then assume a gradual convergence to a long term trend?
d) What is the basis for the long term trend and the rate of convergence to that trend?
e) Please confirm that utility construction cost growth is volatile, and rapid growth for several years has often been followed by much slower growth in the following several years.
f) Did OPG consider making its proposed capex contingent on a specific inflation assumption subject to a true up to actuals? If yes, why did it not propose this?

Response

a) OPG and Kroll did not consider the econometric forecasts from S&P Global's Power Planner service. OPG and Kroll cross-validated multiple independent data sources rather than relying on a single proprietary forecasting tool to provide a broader and more representative view of the cost trends. The analysis provided in Ex. L-A2-CCC-015 Attachments 1 and 2 are based on a comprehensive review of construction cost indices and market data sources, including utility-specific, industrial, and building cost indices from organizations such as Statistics Canada, Construction Analytics, Turner, RSMeans, Marshall & Swift and Handy-Whitman, among others, as listed in the report. Although OPG does not have access to S&P Global's Power Planner service it understands that it also utilizes Handy-Whitman.

b) Not applicable.

c) Kroll did not develop or rely on a standalone econometric forecasting model. Instead, its methodology was based on observed construction cost trends, including the elevated escalation experienced in 2021–2023 across multiple indices, combined with a gradual convergence to a long-term trend informed by historical averages. This is reflected in Kroll's higher near-term forecast escalation rates, (i.e., 5.5% in 2025 and 5.0% in 2026) that taper to a long-term level of approximately 4.6% per year (refer to Ex. L-A2-CCC-015, Attachment 2, p.3).

d) The long-term trend is based on historical analysis across multiple construction cost indices, which provides comparable benchmarks for capital projects. This analysis supports long-term average escalation rates of approximately 4.6%–4.7% (refer to Ex. L-A2-CCC-015, Attachment 2, p.20). Kroll selected approximately 4.6% as the long-term equilibrium rate (refer to Ex. Ex. L-A2-CCC-015, Attachment 2, p. 20) The forecast reflects a measured convergence toward such long-term averages, while recognizing that underlying market conditions continue to reflect sustained construction cost pressures.

e) Utility construction cost growth is inherently volatile. The historical indices reviewed by Kroll demonstrate that periods of exceptional escalation, particularly those observed in 2021-2022, have tended to moderate over time. This pattern is evident across multiple indices presented in the report (refer to Ex. L-A2-CCC-015, Attachment 2, p.28). However, while this moderation is primarily reflective of the normalization of certain factors driving such elevated cost pressures (i.e. supply chain disruptions, labour constraints, and commodity price impacts), Kroll's analysis indicates that current and forward-looking market conditions continue to support sustained demand for construction services. These conditions include the global resurgence in nuclear development, increasing electricity demand driven by electrification and economic growth, and a broader emphasis on energy security and supply chain resilience (refer to Ex. L-A2-CCC-015, Attachment 2, pp. 13-15). Additionally, ongoing global geopolitical uncertainty, as most recently being observed in respect of the ongoing conflict in the Middle East, may continue to exert upward pressure on the cost escalation trends.

   Accordingly, while construction cost escalation is moderating from the 2021-2022 peak levels, it has been forecast to do so toward a long-term average rather than reverting to a prolonged period of unusually low growth. This is consistent with Kroll's approach of gradual normalization, while recognizing that underlying demand conditions in the sector remain strong.

f) The Applicants understand the question to be asking whether they considered proposing a mechanism that would specifically address the revenue requirement impact of differences between (i) the inflation assumptions embedded in the

forecast in-service amounts and (ii) such actual inflation realized over the period. The Applicants did not consider such a mechanism.

Board Staff Interrogatory #344

Interrogatory

Ref 1: Exhibit L / A1-Staff-280
Ref 2: Exhibit L / A1-Staff-277

Preamble:

LEI did not provide a complete answer to question g) in Ref 1. This question pertained to problems with the use of one hoss shay in other studies that Lei has undertaken.

Question(s):

a) Please confirm that LEI obtained implausible results using Handy Whitman Indexes and a one hoss shay capital cost specification and was compelled to instead use a producer price index.
b) Which of LEI's studies in the public domain were affected?
c) Please confirm that this is the source of the typographical error that LEI confirmed in its response to A1-Staff-277.

Response

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

a) LEI does not agree with the characterization in the preamble above regarding other studies, and notes that details of studies in other industries are not applicable or relevant to the hydroelectric industry TFP study prepared by LEI as part of the current proceeding. There is no reason to presume that the data for other industries is sufficiently similar to draw conclusive observations for the hydroelectric generation industry. That said, LEI has seen in its work and the work of others that a combination of specific Handy Whitman Indexes ("HWI") trends applied to reported retirements and long asset lives can create negative real capital stock values. This tends to happen for a few companies that may have had a particular combination of investment and retirements. LEI has never seen it happen to every company in the industry.

   Hyperbolic and geometric depreciation profiles also have limitations. Both profiles require the analyst to disregard reported retirement data entirely, retiring assets according to a mathematical function rather than actual reported retirements. Geometric depreciation assumes assets lose value at a constant proportional rate, producing a rapidly declining profile that does not reflect how hydroelectric

infrastructure (or other assets) actually perform. Utilities routinely operate these assets beyond the economic lives implied by a geometric model, meaning the model understates the productive capital still in service. Both depreciation profiles also require an assumption of the age distribution for the initial capital base, introducing additional judgment calls that can materially affect results.

Therefore, regardless of the depreciation profile selected, assumptions and outputs must be carefully reviewed against practical expectations for the industry.

b) See response to part a).

c) No, that typographical error was a carryover of boilerplate language from another industry study and unrelated to the concern of whether HWI is a good fit for the hydroelectric industry TFP study.

Board Staff Interrogatory #345

Interrogatory

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 31-32
Ref 2: Exhibit L / A1-CCC-005

Preamble:

At Reference 1, OPG states "As shown in Chart 16 below, ScottMadden's econometric analysis concludes that the TGC/MWh of Darlington over the 2021-2023 historic period was $39.58, once the impacts of the DRP and planned outages are accounted for. This performance puts the station in the median or third quintile of the Electric Utility Cost Group ("EUCG") peer group. Accordingly, OPG proposes a nuclear stretch factor of 0.3% based on the range of stretch factors set out by the OEB in the RRF."

At Reference 2, for the purpose of determining the stretch factor, OPG confirms that "The relevant chart is the final chart in Ex. F2-1-1, Attachment 4 that reflects all adjustments applied (i.e., econometric adjustments, refurbishment adjustment, and outage normalization). This chart presents the fully normalized TGC/MWh results and is the basis for the benchmarking comparison used in determining the proposed nuclear stretch factor in Ex. A1-3-2, Section 3.2."

Question(s):

a) The "relevant chart" described in Reference 2 shows Darlington's TGC/MWh is $38.11, whereas $39.58 is shown in Chart 16 corresponds to ScottMadden's analysis without accounting for the planned outages adjustment. Please confirm that OPG intended to cite the final chart on page 13 of Ex. F2-1-1, Attachment 4, rather than the chart on page 11 of Ex. F2-1-1, Attachment 4.

Response

a) Confirmed.

Board Staff Interrogatory #346

Interrogatory

Ref 1: Exhibit L / A1-Staff-002 / Attachment 18, SM Cost Model – With Formulas – BWR Base v4 (For OEB)
Ref 2: Exhibit L / F2-Staff-322

Question(s):

a) Please confirm that:
   i. the purpose of the refurbishment normalization as summarized in Chart 1 in Reference 2 is to remove fixed costs that have been allocated to the unit undergoing refurbishment. If this is incorrect, please explain which costs are removed from TGC.
   ii. the refurbishment normalization as summarized in Chart 1 in Reference 2 does not remove any capital expenditures (column I in tab "Raw EUCG 2023" within Reference 2) that can reasonably be attributed to the refurbishment at Darlington.

b) Please explain whether or not an adjustment for capital expenditures related to the refurbishment at Darlington should be made to TGC and if this adjustment is reflected anywhere in ScottMadden's analysis.

Response

The following responses were prepared by ScottMadden Management Consultants:

a) i) Not confirmed. The purpose of the refurbishment normalization is to remove costs, whether fixed or variable, associated with the unit(s) in refurbishment to provide a more comparable view of cost performance for the operating plant. This normalization methodology was established in 2018 with support from ScottMadden and remains unchanged. For an explanation about the types of costs removed from total generating cost ("TGC") as part of the refurbishment normalization adjustment, refer to Ex. F2-1-1, Section 3.2.1.1, and EB-2020-0290 Ex. F2-1-1, Attachment 4.

a) ii and b) Not confirmed. The refurbishment normalization removes certain capital expenditures associated with the unit(s) in refurbishment, as per the normalization methodology discussed in part a) i).

In addition, capital expenditures related to the Darlington Refurbishment Program as described in Ex. D2-2-1 and Ex. D2-2-3 were already excluded from TGC,

consistent with Electric Utility Cost Group ("EUCG") expectations. As such, no further TGC normalization adjustment for capital expenditures is required.

Board Staff Interrogatory #347

Interrogatory

Ref 1: Exhibit L / A1-Staff-275

Preamble:

In response to A1-Staff-275, OPG has provided hydroelectric annual capital related revenue requirement details (Table 1) and annual O&M revenue requirement details (Table 2) for 2027 through 2031.

Question(s):

a) Please provide an extension of these two annual tables including actual accounting data for 2022 to 2026, annually.

Response

Based on clarifications discussed with OEB staff regarding Ex. L-A1-Staff-348 and this interrogatory, OPG has considered what responsive information could be provided for the regulated hydroelectric facilities in respect of capital related and OM&A amounts reflected in the regulated hydroelectric payment amounts in effect during the 2022-2026 period, recognizing that the payment amounts were legislatively frozen pursuant to *Ontario Regulation 53/05*, section 6(2)13 and accordingly the OEB did not review or approve any hydroelectric revenue requirements for such period. In the absence of OEB-approved amounts for the 2022 to 2026 period, OPG provides below the relevant reference amounts from prior OEB decisions associated with the applicable deferral and variance accounts for the regulated hydroelectric facilities.

Capacity Refurbishment Variance Account – For the capital related portion, per the EB-2016-0152 Payment Amounts Order, Appendix G, p. 9, the annual reference amount (prior to escalation at the price cap index) is $0.9M, which is reflective of the capital in-service additions reflected in the regulated hydroelectric revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321. For the OM&A portion, per EB-2016-0152, Ex. J20.6, the annual reference amount is $0.1M.

Pension & OPEB Cash Payment Variance Account – Per the EB-2020-0290 Payment Amounts Order, Appendix E, p. 12, the annual reference amount for the regulated hydroelectric facilities is $45.1M for OPG's registered pension plan contributions and $12.8M for OPG's other post-employment benefits payments.

Board Staff Interrogatory #348

Interrogatory

Ref 1: Exhibit L / A1-Staff-293

Preamble:

In response to A1-Staff-293, OPG has provided nuclear annual capital related revenue requirement details (Table 2a) and annual O&M revenue requirement details (Table 3a) for years 2027 through 2031.

Question(s):

a) Please provide an extension of these two annual tables including actual accounting data for 2022 to 2026, annually.

Response

Based on clarifications discussed with OEB staff subsequent to the receipt of this interrogatory, OPG provides this response on the basis of the annual capital related revenue requirement ("CRRR") and annual OM&A revenue requirement details for 2022 to 2026, for OPG's nuclear facilities, reflected in the forecasts underpinning the approved nuclear revenue requirements in EB-2020-0290. There were no DNNP facilities at the time of EB-2020-0290. Information in this response is presented using interpretations and assumptions consistent with those applied in Ex. L-A1-Staff-293.

Deferral and variance accounts approved or continued in EB-2020-0290 to track variances related to the CRRR for the 2022 to 2026 in-service additions for OPG's nuclear facilities are the Capacity Refurbishment Variance Account ("CRVA") and the Nuclear Development Variance Account ("NDVA").[1]

Consistent with Ex. L-A1-Staff-293, "rate base as at the end of 2021" as used in this response is based on the sum of the year's (i) net property, plant and equipment closing balance for the nuclear assets and (ii) closing balance of working capital items; it is then reduced annually from 2022 to 2026 from ongoing forecast depreciation and

[1] As noted in Ex. H1-1-1, p. 38, lines 4-7, the NDVA records the revenue requirement differences between actual non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities for OPG and the corresponding OEB-approved forecasts. Since no capital amounts related to potential new nuclear generation projects were included in the approved EB-2020-0290 revenue requirements for OPG's nuclear facilities, there are no CRRR amounts eligible for the NDVA to include in Chart 1 ii).

amortization on these assets.[2,3] Also consistent with Ex. L-A1-Staff-293, simplifying assumptions were used to bifurcate depreciation and amortization and capital cost allowance ("CCA") – between amounts related to assets as at the end of 2021 versus in-service additions during the 2022-2026 IR term – in the calculation of income taxes underpinning the CRRR.[4]

As in Ex. L-A1-Staff-293, for 2022 to 2026 in-service additions where variances are tracked in deferral and variance accounts, in this response OPG considers accounts that (i) 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. Accordingly, Chart 1 ii) provides the requested information for OPG's nuclear facilities with respect to deferral and variance account coverage for in-service additions eligible for the CRVA, based on the EB-2020-0290 approved nuclear revenue requirements.

The information provided in Chart 1 iii) for 2022 to 2026 in-service additions where there are no deferral or variance accounts that would track variances represents, on an estimated basis, the annual breakdown of remaining CRRR underpinning the approved 2022 to 2026 revenue requirements for OPG's nuclear facilities, after accounting for amounts provided in Chart 1 i) and ii).

[2] Depreciation on OPG nuclear rate base as of 2021 as reflected in EB-2020-0290 Payment Amounts Order, App. A, Table 10, line 9, col. (b) for the portion therein related to the 2022 opening balance, held constant throughout the term, except Pickering Units 1 and 4 and Pickering Units 5-8. Since forecasts underpinning the approved 2022-2026 nuclear revenue requirements assumed the end of commercial operation for Pickering Units 1 and 4 at the end of 2022 and Pickering Units 5-8 at the end of 2024 (EB-2020-0290, Ex. F4-1-1, Chart 1), no corresponding depreciation is included for these assets after these dates in Chart 1 i).

[3] The amounts presented in Chart 1 i) in respect of the rate base as at the end of 2021 for OPG's nuclear facilities include impacts from forecast in-service additions for CRVA-eligible projects in 2020 and 2021. Such amounts are subject to the CRVA in those bridge years and the 2022-2026 IR term.

[4] CCA over the 2022-2026 period for the net property, plant and equipment as at the end of 2021 was determined by holding constant throughout the IR term the undepreciated capital cost ("UCC") pool at the end of 2021 subject to applicable CCA rates, with the only change to UCC year-over-year being that of ongoing CCA on these assets.

Chart 1 – EB-2020-0290 Capital Related Revenue Requirement Details – OPG Nuclear

$ million	2022	2023	2024	2025	2026
i. For rate base as at the end of 2021					
Cost of Capital					
Short-Term Debt	2.9	2.8	2.4	2.3	2.3
Long-Term Debt	165.6	152.8	149.5	143.6	136.0
Common Equity	317.9	304.2	287.5	273.6	259.5
EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate	4.6	3.9	3.5	3.1	2.7
Adjustment for Lesser of Unfunded Nuclear Liabilities (UNL) or Asset Retirement Cost (ARC)	3.6	0.0	0.0	0.0	0.0
Total Cost of Capital	494.7	463.7	443.0	422.6	400.4
Depreciation Expense	534.2	462.3	462.3	386.2	386.2
Income Tax Expense	(16.5)	(16.3)	(16.4)	(16.1)	(15.9)
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 2021	**1,012.3**	**909.7**	**888.9**	**792.6**	**770.7**
ii. For 2022 to 2026 in-service additions where variances would be tracked in DVAs					
Cost of Capital					
Short-Term Debt	0.0	0.0	0.8	1.2	1.5
Long-Term Debt	0.0	0.0	48.5	72.9	88.3
Common Equity	0.0	0.0	96.0	142.7	172.6
Adjustment for Lesser of UNL or ARC	0.0	0.0	0.0	0.0	0.0
Total Cost of Capital	0.0	0.0	145.3	216.8	262.4
Depreciation Expense	0.0	0.0	86.4	137.4	175.0
Income Tax Expense[1]	(174.5)	(183.5)	(119.3)	(84.8)	(57.5)
Any other Revenue Requirement Impact	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact relating to 2022-2026 in-service additions that are captured in DVAs	**(174.5)**	**(183.5)**	**112.4**	**269.5**	**379.9**
iii. For 2022 to 2026 in-service additions where there are no deferral or variance accounts that would track variances					
Cost of Capital					
Short-Term Debt	0.0	0.2	0.3	0.4	0.6
Long-Term Debt	1.6	10.6	19.2	26.3	34.7
Common Equity	3.2	21.8	38.1	51.4	67.9
Adjustment for Lesser of UNL or ARC	0.0	0.0	0.0	0.0	0.0
Total Cost of Capital	4.8	32.5	57.6	78.1	103.2
Depreciation Expense	12.9	0.6	18.6	(15.8)	(8.8)
Income Tax Expense	174.5	183.5	119.3	84.8	57.5
Any other Revenue Requirement Impact	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact relating to 2022-2026 in-service	**192.3**	**216.7**	**195.5**	**147.1**	**151.8**

$ million	2022	2023	2024	2025	2026
additions where there is no DVA for variances					

[1] Income taxes associated with the CRRR eligible for the CRVA is primarily related to the Darlington Refurbishment Program ("DRP") CCA, which, as noted in Note 3 of Ex. L-B1-Staff-020, Attachments 1 and 2, is determined at the program level, rather than on a unit-by-unit basis. Therefore, CCA reflected herein is for the DRP overall, rather than isolated to the forecast 2022-2026 in-service additions reflected in the EB-2020-0290 approved revenue requirements.

Deferral and variance accounts approved or continued in EB-2020-0290 to track variances to OM&A expenses for OPG's nuclear facilities for 2022 to 2026 are the CRVA, the NDVA, the Pension & OPEB Cost Variance Account (OPG), the Nuclear Liability Deferral Account ("NLDA"), the Fitness for Duty Deferral Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, the Pickering Closure Costs Deferral Account, and the Clarington Corporate Campus Deferral Account.[5,6,7]

As in Ex. L-A1-Staff-293, for the 2022 to 2026 OM&A costs where variances are tracked in deferral and variance accounts, in this response OPG considers accounts that (i) 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 not conditional on a triggering event, such as the NLDA and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Accordingly, Chart 2 provides the requested information for OPG's nuclear facilities with respect to deferral and variance account coverage for OM&A expenses eligible for the CRVA, the Pension & OPEB Cost Variance Account (OPG) and the NDVA, based on the EB-2020-0290 approved nuclear revenue requirements.

[5] As discussed in Ex. H1-1-1, Section 5.19, the Fitness for Duty Deferral Account records OPG's costs to implement the Canadian Nuclear Safety Commission fitness for duty program requirements, which is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities. Due to uncertainties regarding the cost of the program at the time, no corresponding forecasts were reflected in the approved EB-2020-0290 revenue requirements. Therefore, there are no amounts eligible for this account to include for the 2022-2026 IR term in Chart 2.

[6] As discussed in EB-2020-0290, Ex. A1-3-1, p. 6, lines 1-8, the EB-2020-0290 revenue requirements did not include any costs that would be subject to the Pickering Closure Costs Deferral Account. Therefore, there are no amounts eligible for this account to include for the 2022-2026 IR term in Chart 2.

[7] As outlined in the OEB-approved settlement agreement for EB-2020-0290, OPG's then planned Clarington Corporate Campus was excluded from the revenue requirements that were approved in that proceeding. Therefore, there are no amounts eligible for this account to include for the 2022-2026 IR term in Chart 2.

Chart 2 – EB-2020-0290 OM&A Details – OPG Nuclear

$ million	2022	2023	2024	2025	2026
2022 to 2026 OM&A where variances would be tracked in DVAs					
OPG Nuclear Facilities Base OM&A[1]	11.7	7.0	5.6	0.4	0.0
OPG Nuclear Facilities Project OM&A[2]	34.6	25.8	31.6	27.3	10.8
OPG Nuclear Facilities Outage OM&A[3]	32.4	16.7	13.8	0.0	0.0
Pickering Cyclical Maintenance OM&A	0.0	0.0	0.0	0.0	0.0
DNNP Operational Readiness	0.0	0.0	0.0	0.0	0.0
Allocation of Corporate Costs	0.0	0.0	0.0	0.0	0.0
Allocation of Centrally Held Costs[9]	249.5	230.4	203.6	152.4	88.5
Asset Service Fees	0.0	0.0	0.0	0.0	0.0
Any other OM&A Expense where variances are tracked in a DVA	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact from 2022-2026 OM&A Expenses that are captured in DVAs	**328.1**	**279.8**	**254.6**	**180.2**	**99.3**
2022 to 2026 OM&A where there are no DVAs that would track variances					
OPG Nuclear Facilities Base OM&A[4]	1,282.2	1,277.9	1,266.2	1,047.2	603.0
OPG Nuclear Facilities Project OM&A[5]	78.2	82.5	76.6	72.8	60.1
OPG Nuclear Facilities Outage OM&A[6]	238.4	333.7	192.3	186.8	59.5
Pickering Cyclical Maintenance OM&A	0.0	0.0	0.0	0.0	0.0
DNNP Operational Readiness	0.0	0.0	0.0	0.0	0.0
Allocation of Corporate Costs[7]	365.0	356.7	347.9	314.7	242.9
Allocation of Centrally Held Costs	(64.9)	(68.2)	(55.2)	(49.7)	(73.8)
Asset Service Fees[8]	49.2	52.6	54.6	51.4	47.8
Any other OM&A Expense where there is no deferral or variance account to track variances	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement Impact from 2022-2026 OM&A where there is no DVA for variances	**1,948.0**	**2,035.2**	**1,882.4**	**1,623.1**	**939.6**

[1] Refer to EB-2020-0290, Ex. F2-2-1, Table 1, line 13, cols. (g) to (k).
[2] Sum of EB-2020-0290, Ex. F2-3-1, Table 1, lines 9 to 15, cols. (g) to (k) and EB-2020-0290, Ex. F2-1-1, Table 1, lines 5 to 6, cols. (g) to (k).
[3] Refer to EB-2020-0290, Ex. F2-4-1, Table 1, line 10, cols. (g) to (k).
[4] Ex. F2-2-2, Table 1a, line 21, col. (i) for 2022 and line 42 cols. (c) and (g) for 2023 and 2024, and Ex. F2-2-2 Table 1b, line 63, cols. (a) and (e) for 2025 and 2026, in each case less such Base OM&A costs eligible for deferral and variance accounts (shown in Chart 2 above) for each corresponding year.
[5] Ex. F2-3-2, Table 1, line 18, cols. (g) and (j) for 2022 and 2023 and line 36, cols. (a), (d), and (g) for 2024-2026, in each case less such Project OM&A costs eligible for deferral and variance accounts (shown in Chart 2 above) for each corresponding year, plus EB-2020-0290, Ex. F2-1-1, Table 1, lines 5 and 6, cols. (g) to (k).
[6] Ex. F2-4-2, Table 1a, line 13, col. (i) for 2022 and line 32, cols. (c) and (g) for 2023 and 2024, and Ex. F2-2-2, Table 1b, line 13, cols. (a) and (e) for 2025 and 2026 , in each case less such Outage OM&A costs eligible for deferral and variance accounts (shown in Chart 2 above) for each corresponding year.
[7] Ex. F3-1-2, Table 2a, line 12, col. (i) for 2022 and line 24, cols. (c) and (g) for 2023 and 2024, and Ex. F3-1-2, Table 2b, line 12, cols. (a) and (e) for 2025 and 2026.
[8] Ex. F3-2-2, Table 2a, line 7, col. (i) for 2022 and line 14, cols. (a), (e), and (i) for 2023-2025, and Ex. F3-2-2, Table 2b, line 7, col. (a) for 2026.
[9] Pension and OPEB costs subject to deferral and variance account coverage are presented in this line for purposes of this response.

Board Staff Interrogatory #349

Interrogatory

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 30
Ref 2: Exhibit L / A1-Staff-294

Preamble:

In Reference 1, OPG states "the Application proposes that the OEB continue to exclude costs related to the major refurbishment programs from the calculation of the stretch factor".

In Table 1 of Reference 2, OPG lists cost categories that are not subject to stretch factor.

Question(s):

a) For the line items listed in Table 1, please list those that are related to the major refurbishment programs.
b) For line items in Table 1 that are not related to the major refurbishment programs, please explain why it is appropriate to exclude them from stretch factor calculation.

Response

a) The line items in Table 1 of Reference 2 related to major refurbishment programs are line 6 (Pickering Refurbishment OM&A), line 13 (Total DRP Capital Related Revenue Requirement), line 17 (Total PRP Capital Related Revenue Requirement), line 20 (Income Tax Expense – Capital Cost Allowance for DRP and PRP), and line 23 (Concurrent Cost Recovery – Pickering Refurbishment Program). OPG notes that these amounts represent greater than 80% of the total revenue requirements in Table 1, line 24 over the 2028-2031 period.

b) The line items in Table 1 of Reference 2 not related to the major refurbishment programs are line 2 (Project OM&A – Operations and Project Support), line 7 (Allocation of Centrally Held Costs), line 9a (Fuel Expense), line 18 (Revenue Requirement of Working Capital and Cash Working Capital), line 19 (Revenue Requirement of Asset Retirement Costs), line 21 (Property Tax), and line 22 (Other Revenues). OPG notes that these amounts represent less than 20% of the total revenue requirements in Table 1, line 24 over the 2028-2031 period. Excluding these costs from the application of the stretch factor is consistent with the treatment

approved in EB-2016-0152 and EB-2020-0290. Additional rationale for not applying the stretch factor to the applicable cost categories is provided in Chart 1, below.

Chart 1
Rationale for Excluding from Stretch Factor Applicability

Line No.	Description	Rationale for Excluding from Stretch Factor Applicability
Line 7	Allocation of Centrally Held Costs	These are OPG company-wide costs that are recorded centrally. A number of these costs are primarily externally/market-driven (e.g., IESO non-energy charges, insurance, discount rates and asset earnings for pension costs). As such, they are not expected to drive productivity gains. Additionally, OPG notes that this amount is negative in the 2027-2031 period and applying a stretch factor would increase revenue requirement.
Line 9a	Fuel Expense	Fuel costs are market-based, and productivity gains cannot be expected to reduce these costs. As noted in Ex. L-F2-OAPPA-013, the Applicants assume all nuclear fuel price risk for the IR term, with the exception of any such risks that would be covered by the proposed Change of Laws Deferral Accounts.
Line 18	Revenue Requirement of Working Capital	Working capital included in rate base consists of cash working capital, fuel inventory and materials and supplies. <u>Cash working capital</u> – the amounts included in rate base are formulaic and calculated using the net lag days determined in a lead/lag study in 2019. As such, they are not directly subject to productivity gains. <u>Fuel Inventory</u> – amounts are forecasted based on existing nuclear fuel inventory quantities and expected purchases and usage during the forecast period. Purchases reflect target levels of inventory needed to maintain nuclear safety and ensure reliable energy production, and would not benefit from a productivity stretch. As noted above, fuel costs are market-based and the

Line No.	Description	Rationale for Excluding from Stretch Factor Applicability
		Applicants assume nuclear fuel price risk for the IR term, with the exception of any such risks that would be covered by the proposed Change of Laws Deferral Accounts. Material and supplies – inventory levels do not reflect steady state operations due to variability as Pickering enters the refurbishment outage in 2026 and then as the first unit returns to service in 2031. Over the IR term, OPG will continue to advance materials and supplies efficiency initiatives as explained in Ex. L-B1-CCC-019.
Line 19	Revenue Requirement of Asset Retirement Costs	As discussed in Ex. C2-1-1, these amounts are determined using the same methodologies as in prior OPG applications and reflect the 2022 Ontario Nuclear Funds Agreement Reference Plan and attendant contribution schedule, and are recovered pursuant to O. Reg. 53/05, s. 6(2)8. As such, these amounts are not subject to stretch factor reductions.
Line 21	Property Tax	As discussed in Ex. F4-2-1, Section 6.0, OPG is required to make payments of municipal property taxes and payments in lieu of property tax. As such, productivity gains are not applicable to these costs.
Line 22	Other Revenues	These amounts are not costs, like the other items listed above. These are non-energy revenues included as an offset in the calculation of OPG's nuclear revenue requirements. OPG has not proposed to apply the stretch factor to these items; doing so would typically increase the revenue requirement. Additionally, the application of Bruce Lease net revenues to the revenue requirement is required by O. Reg. 53/05.

1

Board Staff Interrogatory #350

Interrogatory

Ref 1: Exhibit L / C1-Staff-051
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 37-39

Preamble:

In response to C1-Staff-051, Concentric states: "Severe weather is also increasingly leading to regulatory directives and additional reliability standards for utilities."

The response to C1-Staff-051 also refers to the Concentric Report (Exhibit C1-1-1, Attachment 1, pp. 37-39), which states: "In Ontario, since 2020, there have been 14 new or revised NERC Critical Infrastructure Protection ("CIP") standards applicable to OPG requiring updates to its existing processes and the development of new initiatives to ensure compliance."

Question(s):

a) Please provide a list of the new or revised NERC CIP standards applicable to OPG since 2020.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The reference in the response to Ex. L-C1-Staff-051 to Ex. C1-1-1, Attachment 1, pp. 37-39 was to the subsection of Concentric's report titled "Environmental and Severe Weather Risks." The subsection, titled "Cyber Security," begins on page 39, but was not the subject of Concentric's response to Ex. L-C1-Staff-051, which asked about severe weather risk.

   The NERC CIP standards are discussed in the "Cyber Security" subsection of Concentric's report, and were discussed as elements of increasing cyber security requirements applicable to OPG. Please see Attachment 1 for the 14 new or revised NERC CIP standards since 2020. The full spreadsheet is available from the IESO website at https://www.ieso.ca/sector-participants/system-reliability/applicability-criteria-for-compliance-with-reliability-requirements and the version used in the Concentric report was accessed in November 2025.

Standard Number	Standard Group	Standard Number Without Version	Document Title	NERC BOT Adoption Date	USA Approval Status	OEB Start Date	OEB End Date	Review Status in Ontario	Mandatory Enforcement Date in Ontario	Inactive Date in Ontario	Status In Ontario	External Link
CIP-003-7	CIP	CIP-003	Cyber Security — Security Management Controls	2/9/2017	Approved	3/20/2017	7/18/2017	Not Initiated	1/1/2020	3/31/2020	Retired	http://www.nerc.com/pa/Stand/Reliability Standards/CIP-003-7.pdf
CIP-003-8	CIP	CIP-003	Cyber Security — Security Management Controls	5/8/2019	Approved	6/14/2019	9/19/2019	Not Initiated	4/1/2020	6/30/2026	Effective	http://www.nerc.com/pa/Stand/Reliability Standards/CIP-003-8.pdf
CIP-003-9	CIP	CIP-003	Cyber Security — Security Management Controls	11/16/2022	Approved	1/5/2023	5/5/2023	Not Initiated	7/1/2026		Future Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-003-9.pdf
CIP-004-7	CIP	CIP-004	Cyber Security — Personnel & Training	8/12/2021	Approved	9/21/2021	1/19/2022	Not Initiated	4/1/2024		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-004-7.pdf
CIP-005-6	CIP	CIP-005	Cyber Security — Electronic Security Perimeter(s)	8/10/2017	Approved	10/10/2017	2/7/2018	Not Initiated	10/1/2020	9/30/2022	Retired	http://www.nerc.com/pa/Stand/Reliability Standards/CIP-005-6.pdf
CIP-005-7	CIP	CIP-005	Cyber Security — Electronic Security Perimeter(s)	12/21/2020	Approved	1/19/2021	4/28/2021	Not Initiated	10/1/2022		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-005-7.pdf
CIP-008-6	CIP	CIP-008	Cyber Security — Incident Reporting and Response Planning	2/7/2019	Approved	4/1/2019	7/1/2019	Not Initiated	4/1/2021		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-008-6.pdf
CIP-010-3	CIP	CIP-010	Cyber Security — Configuration Change Management and Vulnerability Assessments	8/10/2017	Approved	10/10/2017	10/31/2017	Not Initiated	10/1/2020	9/30/2022	Retired	http://www.nerc.com/pa/Stand/Reliability Standards/CIP-010-3.pdf
CIP-010-4	CIP	CIP-010	Cyber Security — Configuration Change Management and Vulnerability Assessments	6/12/2020	Approved	1/19/2021	4/28/2021	Not Initiated	10/1/2022		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-010-4.pdf
CIP-011-3	CIP	CIP-011	Cyber Security — Information Protection	8/12/2021	Approved	9/21/2021	1/19/2022	Not Initiated	4/1/2024		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-011-3.pdf
CIP-012-1	CIP	CIP-012	Cyber Security – Control Center Communication Networks	8/16/2018	Approved	9/21/2018	1/19/2019	Not Initiated	7/1/2022	9/30/2026	Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-012-1.pdf
CIP-012-2	CIP	CIP-012	Cyber Security – Communications between Control Centers	12/12/2023	Approved	3/21/2024	7/19/2024	Not Initiated	10/1/2026		Future Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-012-2.pdf
CIP-013-1	CIP	CIP-013	Cyber Security - Supply Chain Risk Management	8/10/2017	Approved	10/10/2017	2/7/2018	Not Initiated	10/1/2020	9/30/2022	Retired	http://www.nerc.com/pa/Stand/Reliability Standards/CIP-013-1.pdf
CIP-013-2	CIP	CIP-013	Cyber Security - Supply Chain Risk Management	12/12/2020	Approved	1/19/2021	4/28/2021	Not Initiated	10/1/2022		Effective	https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-013-2.pdf

Board Staff Interrogatory #351

Interrogatory

Ref 1: Exhibit L / C1-Staff-040
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 48
Ref 3: Excel File "L-C1-CCC-026_Attachment 1 CEA Exhibits – Credit Metric Analysis Workpaper.xlsx"

Preamble:

In response to C1-Staff-040, Concentric states:

"To summarize the assumptions used to generate Figure 10:

- The analysis estimates cash flow metrics based on the after-tax return on rate base at different equity ratios, adjusted for items that impact cash flow.
- Inputs to the calculations such as rate base, cost of debt, income taxes, depreciation, adjustments for other items impacting cashflow from operations (including pension/OPEB and nuclear liability related expenses and expenditures), pension & OPEB liabilities, and the pension & OPEB allocation are sourced from the OPG Exhibits in this Application as identified in the "Formula/Source" column. The formulas used to calculate various items in the analysis are also described in that column.
- A return on equity of 9.11% is assumed throughout the analysis period.
- Amounts do not reflect OPG's payment amounts shaping proposal in this Application or the availability of Clean Electricity Investment Tax Credits.
- Although a decrease from OPG's proposed equity thickness of 52% could negatively impact the cost of debt (for instance, by reducing cash flows that debt investors evaluate in their assessments of credit risk), conservatively, no assumption of such impact has been reflected in this analysis.
- As OPG's pension and OPEB liabilities are not segregated for ratemaking purposes, an allocation factor was applied to allocate a portion of OPG's pension and OPEB liabilities to the prescribed facilities consistent with the factor used to allocate OPG's pension & OPEB costs to the prescribed facilities for ratemaking purposes."

This response also references the Excel file "L-C1-CCC-026_Attachment 1 CEA Exhibits - Credit Metric Analysis Workpaper.xlsx." Please refer to rows 31, 32, 63, and 64 of this Excel file.

The FFO/Debt measure uses a measure of debt equal to:

$$Debt_{FFO\ Ratio} = Total\ Debt + (OPEB\ Liabilities + Pension\ Liabilities)$$

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

$$* (1 - Income\ Tax\ Rate) * Pension\ Allocation$$

The CFO/Debt measure uses a measure of debt equal to:

$$Debt_{CFO\ Ratio} = Total\ Debt + (Pension\ Liabilities) * Pension\ Allocation$$

Question(s):

a) Please confirm that the formulas in the preamble of this question accurately reflect what is displayed in this Excel spreadsheet. If this is not the case, please explain.
b) Please explain why the debt measures for FFO/Debt and CFO/Debt differ.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Confirmed. The formulas in the preamble accurately reflect the formulas in the Excel spreadsheet.

b) In credit analysis, Moody's Corporation and S&P Global measure debt differently whereby S&P adjusts debt for the after-tax amount of OPEB Liabilities and Pension Liabilities, while Moody's adjusts debt for the pre-tax amount of Pension Liabilities.

Board Staff Interrogatory #352

Interrogatory

Ref 1: Exhibit L / C1-Staff-050

Preamble:

Question C1-Staff-050(b) asks:

"Please explain why none of the companies that appear in the proxy group for the capital structure analysis were included in the sample of utilities used in the comparison of bond spreads."

The response reads:

> "As noted in footnotes 103 and 104 in Concentric's report (Ex. C1-1-1, Attachment 1, p. 51), the new credit spread analysis reflected in Figures 11 and 12 was based on data provided to OPG by Bank of Montreal, Bank of Nova Scotia, Canadian Imperial Bank of Commerce, National Bank Financial, Toronto-Dominion Bank, and Royal Bank of Canada, and thus reflects data as provided to OPG from the cited banking institutions. Based on this available data, the credit spread analysis demonstrates both that OPG is perceived from a financial perspective to be of higher risk than similarly rated utilities and further demonstrates that credit ratings alone do not fully capture investor sentiment regarding utility risk."

The purpose of the question was to understand why an analysis of capital structures and an analysis of credit ratings would require a wholly separate set of peer companies with no overlap.

In addition, all of the companies but one in this list (EPCOR Utilities Inc.) appear to have a higher credit rating than OPG.

Question(s):

a) What is meant by "similarly rated utilities"?
b) If five of the "similarly rated utilities" in the credit spread have a higher credit rating than OPG, should the peer group for this analysis also contain five companies with lower credit ratings than OPG to balance the credit spread results?
c) Is a company with an S&P rating of A+ "similarly rated" to a company with an S&P rating of BBB+?

d) What value is gained by determining a credit spread using the bond yields of a particular company with the bond yields of a set of companies that have different credit ratings?
e) If the companies in the credit spread analysis are comparable to OPG, why are these companies not included in the capital structure analysis?
f) If the companies in the capital structure analysis are comparable to OPG, why are these companies not included in the credit spread analysis?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

The purpose of the credit spread analysis was to provide, as additional context, a broad, market-based measure of risk (i.e., credit spreads) and to assess whether that measure provides insight into OPG's perceived credit risk beyond what may be conveyed by credit ratings alone.

As OPG is rated in the A-category by two rating agencies (A3 by Moody's and A (low) by DBRS) and BBB+ by S&P, the credit spread analysis focused on the utilities that fall within the broad A investment-grade category, notwithstanding differences at the individual rating notch level and other risk distinctions among issuers. For clarity, the analysis specifically considers credit risk as viewed by debt investors and does not reflect the residual risk borne by equity investors.

As discussed in Ex. L-C1-Staff-050, the credit spread analysis is anchored in Canadian utility issuers based on available data. Furthermore, for this purpose, it is appropriate to compare OPG to other Canadian issuers, given the role of Government of Canada bonds as the domestic risk-free reference.

With that background, the specific questions are addressed below.

a) "Similarly rated utilities" in this context refers to utilities that can generally be classified as investment-grade, A-category issuers based on their ratings from S&P, Moody's, DBRS, and Fitch.

b) No. The objective of the credit spread analysis is to examine how OPG's bond spreads compare to those of A-category, Canadian investment-grade utilities.

c) No. However, while A+ and BBB+ are not identical ratings from S&P, this analysis reflects OPG's composite rating profile (A-category from two of three agencies) and considers it sufficiently comparable to the A-category peer group.

d) See the preamble to this response.

e) See the preamble to this response. As discussed above, the purpose of the credit spread analysis was to isolate a market-based measure of credit risk and assess whether it provides insight beyond credit ratings alone. The analysis was not intended to identify an alternate proxy group for purposes of Concentric's Fair Return Standard ("FRS") analysis.

f) The companies included in Concentric's FRS analysis were screened to provide comparability from an equity investor's perspective. By contrast, the credit spread analysis is focused on financial risk as viewed by debt investors and is limited to Canadian issuers based on the availability of data. In addition, the credit spread analysis is appropriately anchored in Canadian utility issuers given the role of Government of Canada bonds as the domestic risk-free reference for Canadian issuers.