EB-2020-0290

ONTARIO POWER GENERATION

COMPENDIUM OF MATERIALS

FOR ISSUES DAY

SCHOOL ENERGY COALITION

ONTARIO REGULATION 53/05

Payments under Section 78.1 of the Act

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

> 13. In making its first order under section 78.1 of the Act that is effective on or after January 1, 2022 setting payment amounts for the hydroelectric facilities, the following rules apply:
>
> > i. The order shall provide for a base payment amount for the hydroelectric facilities that is equal to the base payment amount for the hydroelectric facilities on December 31, 2021, and that applies until the effective date of a subsequent order setting payment amounts for the hydroelectric facilities that comes into effect after Dec 31, 2026.
> >
> > ii. Subparagraph i applies with respect to only 50 per cent of the output of the Chats Falls generation facility. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2; O. Reg. 622/20, s. 3 (1).

(3) For greater certainty, the rule set out in paragraph 13 of subsection (2) does not affect any authority of the Board to approve,

(a) changes to the hydroelectric incentive mechanism applicable to Ontario Power Generation Inc.;

(b) the establishment of or changes to deferral or variance accounts relating to the hydroelectric facilities; or

(c) the recovery of any amounts relating to the hydroelectric facilities that are recorded by Ontario Power Generation Inc. in a deferral or variance account referred to in clause (b), or any related payment amount riders. O. Reg. 622/20, s. 3 (2).

Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15 Schedule B

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Statutory Powers Procedure Act

R.S.O. 1990, CHAPTER S.22

Consolidation Period: From April 19, 2021 to the e-Laws currency date.

Dismissal of proceeding without hearing

4.6 (1) Subject to subsections (5) and (6), a tribunal may dismiss a proceeding without a hearing if,

(a) the proceeding is frivolous, vexatious or is commenced in bad faith;

(b) the proceeding relates to matters that are outside the jurisdiction of the tribunal; or

(c) some aspect of the statutory requirements for bringing the proceeding has not been met.

Notice

(2) Before dismissing a proceeding under this section, a tribunal shall give notice of its intention to dismiss the proceeding to,

(a) all parties to the proceeding if the proceeding is being dismissed for reasons referred to in clause (1) (b); or

(b) the party who commences the proceeding if the proceeding is being dismissed for any other reason.

Board Staff Interrogatory #8

Interrogatory

Reference:
Exhibit A1 / Tab 3 / Schedule 2 / p. 13
Exhibit I1 / Tab 1 / Schedule 1 / p. 2

Preamble:

OPG proposed to continue its existing off-ramp provision (+/- 300 basis points deadband for determining whether a regulatory review should be initiated) in the 2022-2026 Custom IR term.

OPG achieved earnings in excess of the OEB-approved return on equity (ROE) in 2019 and forecasts that it will do so again in 2020 and 2021.

Question(s):

a) Please provide OPG's views on the inclusion of an asymmetrical earnings sharing mechanism (ESM) for the 2022-2026 Custom IR term.

b) Please discuss whether it is possible to apply the ESM only to earnings generated by the nuclear business or could only be applied for earnings generated by the entire regulated business (both hydroelectric and nuclear).

c) Please provide OPG's views on an ESM structure whereby: (a) the first 100 basis points of earnings in excess of the OEB-approved ROE is to the benefit of OPG's shareholder; (b) earnings between 100-200 basis points above the OEB-approved ROE are shared 50:50 with ratepayers; and (c) earnings in excess of 300 basis points above the OEB-approved ROE are shared 90:10 to the benefit of ratepayers.

Response

a) and c)

While OPG does not believe that an ESM is necessary, if an ESM were established for the IR Term, OPG's view is that it should operate on a symmetrical basis to reflect the risk associated with OPG's regulated assets. OPG's earnings are prone to significant variations year-over-year due to the volumetric nature of its payment amounts and variable production. As demonstrated in Chart 1, over the 2008 to 2019 period, OPG's actual ROE has ranged from approximately 900 basis points below the +/-300 basis points deadband to approximately 300 basis points above it.[1]

Chart 1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Actual	(3.11)%	1.10%	4.71%	4.80%	4.73%	0.46%	6.32%	3.63%	3.80%	5.91%	10.69%	15.61%
OEB-Approved	8.65%	8.65%	8.65%	9.43%	9.55%	9.55%	9.36%	9.30%	9.30%	9.16%	9.16%	9.16%

Average (2008-2019)
4.89%

Average (2017-2019)
10.74%

On average, OPG has performed below the bottom end of the deadband, with lower earnings being only partially offset by higher earnings in other years. An asymmetrical ESM could increase OPG's overall exposure to production-related risks, potentially substantially.

Further, it is OPG's view that that the division of benefits under an ESM should not unduly diminish the incentive for a utility to continue driving continuous improvement over the period.

Accordingly, OPG believes that, if an ESM were established, it should reflect the volatility in OPG's earnings by sharing risk of both over- and under-earning and reflect a division of benefits that incents continuous performance.

b) As stated in EB-2016-0152, Ex. L-1.2-5 CCC-006, OPG operates as a single company, with a single management structure, a single corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities. OPG obtains corporate financing as a single company. Accordingly, OPG reports achieved return on equity for the prescribed facilities as a whole. For these reasons, OPG believes that it would be appropriate for any earnings sharing to be done on the same total regulated company basis, rather than on a nuclear only basis. To do otherwise, while mathematically possible, would be inconsistent with the basis on which payment amounts are set and therefore would not meaningfully compare the financial performance of OPG's regulated business relative to the OEB-approved ROE.

OPG understands that the reference to "earnings between 100-200 basis points above the OEB-approved ROE" in the question is intended to read "earnings between 100-300 basis points above the OEB-approved ROE."

[1] Ex. L-H1-01-AMPCO-178, Attachment 1, Chart 1.

assuming that the marketplace also values and sees that option going forward.

MR. SHEPHERD: Okay. Have you had any discussions with the rating agencies about the impact of this direction on either your ratings or -- and their risk perception or the cost of capital, the cost of debt?

MR. SHEPHERD: In discussion with the rating agencies, we are always looking for ways to position OPG in a way that obviously supports our investment rate credit rating, the fact that we are a clean energy generator and are starting to expand on our disclosures related to ESG, I think they would be supportive of that, but I'm not necessarily sure they're giving that much weight or credence to that in comparison to other risks they would be evaluating for us.

MR. SHEPHERD: And what I'm asking is, when you're talking to the rating agencies, are they reacting positively, negatively, neutral?

MR. MAUTI: The fact we are looking at these products and are positioning our financial disclosures this way is at least seen in a positive light as opposed to not.

MR. SHEPHERD: All right. I want to go to page 60, and this shows the regulated hydroelectric results, the segmented results from 2019 and 2020, and if I understand this correctly, your revenue was higher in 2020, but that's, I think, just a function of it goes up and down every year. But your OM&A went down and your depreciation went down. Am I right?

MR. KOGAN: The OM&A year-over-year did decrease, as shown here. The depreciation amortization in totality also decreased as shown here as well. Not to anticipate the question, but on the depreciation and amortization front in particular, the decrease is likely due to simply lower recoveries of deferral and variance accounts. So this is not fixed-asset depreciation, this is just amortization of regulatory balances and goes up and down without recovery through-riders.

MR. SHEPHERD: Are you able to break those two figures out, the 224 and the 214, between actual depreciation, like depreciation of PP&E, and amortization of regulatory assets? It's not in your financial disclosures here anywhere, but I'm sure you have those numbers.

MR. KOGAN: We certainly have the numbers, and it could be done. I'm just trying to understand what it's clarifying in terms of the context of this application.

MR. SHEPHERD: Well, so you're -- let me go on to the next question, then I'll circle back to it.

As Mr. Mauti has just said a few minutes ago, the interest costs associated with the hydroelectric rate base will also be going down, right?

MR. KOGAN: I don't want to speak for Mr. Mauti. I think what we said was that to the extent we were able to issue debt that brings down the overall corporate weighted average down that is attributable to the regulated business, then the actual deemed interest cost will decrease, and that's a correct statement.

MR. SHEPHERD: So -- and then the other thing is your taxes also are going down, because there are new tax rules in effect that allow you to accelerate some of your CCA.

MR. KOGAN: We record the impact of the enhanced CCA rules -- I think you're referring to the accelerated investment property -- in the appropriate variance accounts, either the CRVA or the income and the taxes variance account, and that includes the hydroelectric business, so therefore those impacts would not benefit, so to speak, our bottom-line tax expense.

MR. SHEPHERD: Oh, okay. Am I right that we can expect that 2021 numbers, in terms of earnings before interest and income taxes and earnings after interest, will also be relatively better than these ones, assuming similar generation?

MR. SMITH: Mr. Shepherd, can you help me with the relevance of this to this application?

MR. SHEPHERD: Yes. There is a disputed issue, and the issue is whether the Board continues to have jurisdiction to determine whether the hydroelectric payment amounts currently in place should remain in place for December 31st, 2021. And so I'm asking questions about the decline in costs at OPG for its hydroelectric business.

MR. SMITH: We're not going to answer those questions. I don't agree that -- I don't agree with the position that that is a relevant line of inquiry, having regard to the regulation.

MR. SHEPHERD: Okay. I'll take that as a refusal.

MR. MAUTI: I think at the very end of that response where it gets into how it is that we look at managing nuclear liabilities in terms of whether it's Bruce or prescribed, where I was trying to look to ways to ensure that we can discharge our obligations in the most efficient way possible, so that's the way we would go about approaching it, where liabilities, regardless of Bruce, versus the prescribed facilities, that would be our approach to try to manage those costs.

MR. SHEPHERD: So basically whatever you're doing to manage your own costs, whether it's liabilities or anything else, but let's say liabilities, which is the biggest cost, obviously, whatever you do to manage your own costs would also, to the extent that it relates to Bruce or to the extent that it carries over, you would do the same things to manage those costs?

MR. MAUTI: Yes, I would suggest that we don't do anything specific for Bruce versus prescribed when it comes to the costs, and again, as you mentioned, the majority of the costs related to the Bruce are tied to nuclear liabilities, and so there is a distinct set of options looking at the Bruce versus prescribed in that case.

MR. SHEPHERD: All right. Second -- my next question is A2-02-SEC-13, and this relates to net income for the regulated businesses.

MR. KOGAN: We can wait for that to be pulled up, but I do recall the response, Mr. Shepherd.

MR. SHEPHERD: All right. So you said you don't track a report net income separately for the regulated facilities, but your financial statements do segregate it between regulated hydroelectric and regulated nuclear, so I'm not sure I understand the answer.

MR. KOGAN: The financial statements segregate these amounts at the segmented level at the earnings before interest tax line, not at the net income.

MR. SHEPHERD: Okay. So can you give us -- can you answer the question on the basis of -- the only -- sorry, before interest and tax or before -- are we talking about EBITDA, or are we talking about earnings before EBIT?

MR. KOGAN: It's EBIT, so it's the latter, sir.

MR. SHEPHERD: Okay. So can you answer this question giving us EBIT? Do you have a forecast like that or can you produce one?

MR. KOGAN: The information is available within our business plan. This would be on an accounting basis, not on a regulated basis, and again, I'm sort of wondering from a hydroelectric perspective how this applies.

MR. SMITH: We're not going to provide it in relation to the regulated hydroelectric facilities.

MR. SHEPHERD: Is this in the business plan? This information? I didn't find it --

MR. KOGAN: This information is not in the business plan document, no, it is not.

MR. SHEPHERD: But you have it?

MR. KOGAN: Within the models that underlie our business plan we are able to estimate this information;

that's correct.

MR. SHEPHERD: But you're refusing to provide it?

MR. SMITH: We're refusing to provide it in relation to the regulated hydro facilities, yes.

MR. SHEPHERD: Awesome. Thank you. Now, I have a number -- I think basically all the rest of my questions, I'm not sure, but many of the rest of my questions relate to cost of capital, and these responses are mostly prepared by Concentric. I don't understand why Concentric was not -- why you don't have a Concentric witness at this technical conference. But what I'm going to do is I'm going to ask the questions, and if you can answer them you can answer them. If you can't answer them then you'll undertake them, I guess. Okay?

The first one is C1-01-SEC-20. And the thing I don't understand is, it's true, isn't it, that once you've completed the Unit 2 of the Darlington refurbishment plan, the -- or project, rather, your risk goes down because you know a lot more, right? Just operationally you're in a better position after you complete the first unit; is that right?

MR. KOGAN: I think I'll answer on behalf of the panel that certainly there would be an element of increased learning and opportunities to apply some of that learning to future units. I'm sure our Darlington refurbishment evidence speaks to those opportunities.

MR. SHEPHERD: Okay. Then my next question relates to SEC 21, which is the next one. And this -- we asked about

SEC Interrogatory #46

Interrogatory

Reference: C1-1-2, Table 12

Please confirm that the actual cost of interest on long term debt applicable to the regulated hydroelectric facilities for the period 2022-2026 is forecast to be approximately $130 million lower than the interest cost embedded in rates for that period.

Response

OPG declines to respond on the basis of relevance. O. Reg. 53/05 section 6(2), 13, i, establishes the Hydroelectric payment amounts for the period covered by this application at the level that exists on December 31, 2021. As such, the information sought is not relevant to any issue before the OEB in this application.

SEC Interrogatory #1

Interrogatory

Reference: A1-2-1, p.1,2, A1-3-1, p.2

Please confirm that O.Reg. 53/05, s. 6(2)(13)(i) stipulates that the hydroelectric payment amounts for 2022 through 2026 shall be the payment amount in effect on December 31, 2021, not January 1, 2021. Please confirm that, except for adding riders of $1.33/MWh for the first three years, and $0.69/MWh for the last two years, in both cases pursuant to s. 6(3)(c), OPG is proposing that no changes be made to the current hydroelectric payments amount between now and December 31, 2021.

Response

OPG confirms that O. Reg. 53/05, s. 6(2)(13)(i) requires that the base hydroelectric payment amount for 2022-2026 be set equal to the base payment amount in effect on December 31, 2021.

OPG confirms it is seeking to establish deferral and variance account hydroelectric riders of $1.33/MWh for 2022-2024 and $0.69/MWh for 2025-2026.

OPG confirms it is not seeking to make any changes to the hydroelectric base payment amounts between now and December 31, 2021.

SEC Interrogatory #154

Interrogatory

Reference: H1-1-1, p.18

Please provide a table comparing the forecast $2 billion in hydroelectric capital additions annually to the proposed $153 million annual reference amount, and provide a forecast of the balance in the Hydroelectric CRVA as of December 31, 2026.

Response

OPG declines to provide the requested information on the basis of relevance. OPG is not seeking to recover actual or forecast hydroelectric balances in the CRVA in the application (see Ex. H1-1-1, p. 18).

OSEA Interrogatory #7

Interrogatory

Reference: Exhibit I1-3-2, page 5

Please confirm that OPG is planning to add 200 MW of new hydroelectric capacity over the 2022-2026 term and that overall output is expected to be higher than previous forecasts.

Response

Although not the subject of this application, OPG confirms that, as stated in its 2020-2026 Business Plan (Ex. A2-2-1, Attachment 1), OPG is planning to add approximately 200MW of incremental capacity to its Ontario-based fleet by the end of the business plan period.

OPG's 2022-2026 forecast of regulated hydroelectric generation (before surplus baseload generation impact) in the 2020-2026 Business Plan is provided at Ex. A2-2-1, Attachment 1, p. 22. The forecast in each year ranges from 33.0 TWh to 33.8 TWh. In most years, this is slightly higher than the last OEB approved production forecast from EB-2013-0321 of 33.0 TWh.[1]

[1] Represents 2014 and 2015 average of OEB-approved hydroelectric production per EB-2013-0321 Decision and Order p. 9, and as per EB-2016-0152 Payment Amounts Order, App. I, Table 2, line 3.

Numbers may not add due to rounding.

Table 24

Corporate Support & Administrative Groups OM&A Costs - OPG ($M)[1]

Line No.	Corporate Costs	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Chief Information Office	155.1	152.6	145.5	149.8	148.1	154.7	157.0	157.1	152.3	144.4	120.7
2	Real Estate[2]	31.3	38.1	39.9	40.1	46.9	53.7	51.0	51.0	51.0	49.3	30.9
3	Supply Chain	50.3	53.9	53.9	51.0	52.4	46.5	45.6	45.4	45.0	37.3	32.3
4	Finance	48.3	47.4	46.5	43.5	41.1	45.6	46.3	46.0	46.5	44.8	44.7
5	Human Resources	29.9	32.2	30.5	30.1	26.7	29.2	28.8	28.6	26.9	27.4	23.2
6	Environment, Health & Safety	20.6	21.5	21.4	21.5	25.9	27.4	24.4	24.3	24.6	24.6	19.4
7	Corporate Centre	61.7	61.4	56.1	61.1	60.0	66.7	62.9	61.9	63.0	61.7	61.2
8	**Total Base OM&A**	**397.3**	**407.1**	**393.7**	**397.1**	**401.0**	**423.9**	**416.0**	**414.3**	**409.2**	**389.4**	**332.4**
9	**Leases & Utilities[3]**	30.7	35.3	35.7	34.3	26.8	29.4	32.9	31.4	30.1	19.7	17.4
10	**Project OM&A**	**32.8**	**28.9**	**28.7**	**21.3**	**26.5**	**30.4**	**33.9**	**27.4**	**31.9**	**26.7**	**21.6**
11	**Total OM&A**	460.8	471.3	458.0	452.7	454.3	483.7	482.9	473.1	471.3	435.8	371.4

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2016-0152 for organizational changes and transfers to/from Nuclear Support and Renewable Generation & Power Marketing (formerly Hydro-Thermal Operations) as descr bed in Ex. F3-1-1.

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

3 Formerly included in Real Estate in EB-2016-0152

Numbers may not add due to rounding.

Table 25

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

Line No.	Corporate Group	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Chief Information Office	120.8	122.7	117.4	123.1	130.1	135.8	137.1	137.3	131.7	121.0	90.9
2	Real Estate[2]	30.9	37.2	39.4	39.6	45.7	52.7	50.2	50.2	49.5	47.5	28.8
3	Supply Chain	45.1	48.3	49.2	45.6	47.7	43.2	42.3	42.0	41.5	33.3	27.5
4	Finance	34.5	36.0	34.5	29.8	26.7	32.3	32.2	32.4	32.5	29.6	26.5
5	Human Resources	23.4	25.0	23.2	23.3	20.4	22.7	22.2	22.0	20.1	19.7	14.7
6	Environment, Health & Safety	13.8	15.2	15.2	14.4	17.9	18.9	16.0	16.1	15.8	15.5	10.1
7	Corporate Centre	41.8	38.8	37.1	39.1	37.9	40.0	33.7	33.0	32.5	30.0	24.7
8	**Total Base OM&A**	**310.4**	**323.1**	**316.0**	**314.9**	**326.6**	**345.6**	**333.7**	**332.9**	**323.6**	**296.7**	**223.1**
9	**Leases & Utilities[3]**	25.9	31.5	30.8	28.3	22.7	26.8	28.3	27.1	26.9	17.5	14.9
10	**Project OM&A**	**24.2**	**22.3**	**21.8**	**18.5**	**20.8**	**23.7**	**26.0**	**20.0**	**24.8**	**20.1**	**14.9**
11	**Total OM&A**	360.5	377.0	368.6	361.7	370.1	396.1	387.9	380.0	375.3	334.3	252.9

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2016-0152 for organizational changes and transfers to/from Nuclear Support and Renewable Generation & Power Marketing (formerly Hydro-Thermal Operations) as descr bed in Ex. F3-1-1.

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

3 Formerly included in Real Estate in EB-2016-0152

Numbers may not add due to rounding.

Table 30
Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Accrual Costs**	207.4	94.7	154.2	118.4	12.8	32.1	15.4	(7.6)	(37.9)	(53.6)	(77.4)
2	**OPG-Wide Insurance**	21.7	21.3	20.6	21.6	25.3	31.3	34.4	36.0	36.9	34.6	37.2
3	**Nuclear Insurance**	8.8	14.5	17.1	18.0	19.5	22.4	24.6	27.1	30.0	26.2	14.9
4	**Performance Incentives**	21.7	32.6	28.6	29.6	32.7	32.2	32.5	32.8	32.9	29.9	27.6
5	**IESO Non-Energy Charges**	120.2	137.6	100.1	110.3	133.5	115.3	113.9	104.5	115.7	77.9	32.7
6	**Other**	23.3	2.9	(2.8)	(5.2)	35.1	18.1	15.3	15.3	5.1	17.2	13.7
7	**Total**	403.2	303.5	317.8	292.6	258.9	251.3	236.1	208.0	182.6	132.3	48.7

Numbers may not add due to rounding.

Table 31

Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	Costs	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Accrual Costs**	161.7	76.2	122.9	93.9	10.2	25.2	12.0	(5.9)	(29.2)	(40.4)	(56.2)
2	**OPG-Wide Insurance**	5.8	6.9	6.7	6.9	8.3	10.3	11.3	11.9	12.1	11.3	6.4
3	**Nuclear Insurance**	8.8	14.5	17.1	18.0	19.5	22.4	24.6	27.1	30.0	26.2	14.9
4	**Performance Incentives**	16.6	25.9	22.3	24.1	27.2	26.9	27.3	27.6	27.8	24.6	21.5
5	**IESO Non-Energy Charges**	88.8	109.5	81.2	97.4	113.2	98.8	97.7	89.4	99.9	64.6	19.9
6	**Other**	24.3	10.0	5.9	(1.8)	37.2	13.7	11.6	11.5	3.4	12.5	8.3
7	**Total**	306.0	242.9	256.2	238.6	215.6	197.2	184.5	161.6	143.9	98.9	14.7

Notes:

1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the test period reflects OPG's proposal to include accrued amounts for pension and OPEB in the nuclear revenue requirement.