ONTARIO POWER GENERATION

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VIA RESS AND OVERNIGHT COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0152 – Ontario Power Generation Inc. 2017-2021 Payment Amounts Application – Amendment to the Pre-filed Evidence and Interrogatory Responses

Enclosed are amendments to OPG's pre-filed exhibits and interrogatory responses. OPG has submitted these documents through the Regulatory Electronic Submissions System and is providing twelve (12) paper copies. This material will also be available on OPG's website at www.opg.com. Attachment 1 is a table listing the amended exhibits.

A description of the amended material is provided below:

Exhibit	Description of the Change
A1-3-3 Nuclear Rate Smoothing and Midterm Production Review	Page 6 – Numerical: Total values in Chart 1 have been corrected. Page 8 – Missing label has been added to Row 7 of Chart 3.
D2-1-3 Table 4 Comparison of In-Service Capital Additions – Nuclear Operations ($M)	Lines 1, 2 and 3 – Numerical: 2013 actual in-service amounts and changes from 2013 Budget and 2014 Actual for Darlington NGS, Pickering NGS and Nuclear Support Divisions have been corrected. Lines 4, 6 and 8 – Numerical: 2013 actual in-service amounts and changes from 2013 Budget and 2014 Actual have been corrected to reflect changes in Lines1, 2 and 3 as described above.
D2-2-3 Major Work Bundle Structure and Contracts	Page 11, Lines 5-12 – New sub-bullet has been added to explain an additional feature common to all scenarios. Page 11, Lines 20-21 and Page 13, Lines 6-7– Description has been added to clarify which neutral bands are being referenced. Page 11, Line 25, Page 12, Line 17, Page 13, Line 10 and Page 14, Line 12 – Chart numbers had erroneously been restarted at Chart 1. Charts have renumbered to Charts 4-7. Page 12, Lines 8-10 and Page 13, Lines 17-21 – Statements regarding the position of scenarios in comparison to the

Exhibit	Description of the Change
	neutral band and application of incentives/disincentives have been corrected for both the definition and execution phases. Page 12, Chart 5, Line 3, and Page 14, Chart 7, Line 3 – Numerical: Impact to Contractor, Impact to OPG and OPG Payment to Contractor amounts have been corrected for Definition Phase Fixed Fee Incentive/Disincentive. Page 12, Chart 5, Line 12, and Page 14, Chart 7, Line 12 – Numerical: Impact to Contractor, Impact to OPG and OPG Payment to Contractor amounts have been corrected in the Total line to reflect changes in Line 3.
F2-1-1 Table 1 Operating Costs Summary – Nuclear ($M)	Line 15 – Numerical: 2014 actual Property Tax has been corrected. Line 16 – Numerical: 2014 Total Operating Cost has been corrected to reflect the change in Line 15.
F2-2-3 Pickering Extended Operations	Page 4 – Chart 1 has been replaced to correct an error in the data as identified in OPG's response to Board Staff Interrogatory #116 (L-06.5-1 Staff 116).
F2-4-1 Table 3 Outage OM&A by Resource Type – Nuclear ($M)	Line 36 – Numerical: The breakdown of Labour and Non-Regular Labour amounts for Nuclear Support Divisions has been revised. Line 37 – Numerical: Labour and Non-Regular Labour Amounts in the Total Outage OM&A have been revised to reflect the changes in Line 36.
F2-6-1 OM&A Purchased Services Nuclear Operations	Page 1, Line 24 – Numerical: The 2014 total purchases for vendors amount has been corrected.
F4-2-1 Table 2 Taxes – Nuclear ($M)	Line 2 – Numerical: 2014 Actual Property Tax for Darlington NGS has been corrected. Lines 4 and 5 – Numerical: 2014 actual amounts have been corrected to reflect the change in Line 2.
F4-2-1 Table 4 Reconciliation of OPG's Tax Returns to Regulatory Income Tax Calculation for Prescribed Facilities ($M)	Line 22 – Label has been changed to align with the actual name of the deferral and variance account.
F4-3-1 Compensation and Benefit	Page 8, Line 11 – The date of PWU Collective Agreement expiry has been corrected.
F4-4-1 Centrally Held Costs	Page 4, Lines 3, 4 and 5 – Revised to provide further explanation on the trends and variances of OPG-wide insurance costs.
G2-2-1 Table 8 Calculation of Bruce Income Taxes ($M)	Line 23 – Reference to Note 3 has been added. Notes – Note 3 has been added.
I-1-1- Table 2 Comparison of Revenue Requirement to OEB Approved – Nuclear ($M)	Line 1 – Numerical: 2014 and 2015 actual Total Costs of Capital have been corrected. Line 5 – Numerical: 2014 actual Property Tax has been corrected. Line 6 – Numerical: 2014 actual Total Expenses has been corrected to reflect the change in actual property tax. Line 10 – Numerical: 2015 actual Income Tax has been corrected.

Exhibit	Description of the Change
	Line 11 – Numerical: 2014 and 2015 actual Revenue Requirements have been corrected. This change was also submitted in Attachment 1 of OPG's response to AMPCO Interrogatory #11(L-01.3-2 AMPCO-011).
L-01.2-5 CCC-008	Nuclear Operations and Projects panel has been added to the Witness Panel at the bottom of the interrogatory.
L-02.1-2 AMPCO-013 Attachment 1, Table 1	Row 1 – Numerical: 2013 Actual and 2015 Board Approved Nuclear Operations Capital Projects in-service additions have been corrected. Row 2 – Numerical: 2015 Board Approved Darlington Refurbishment Program in-service additions has been corrected. Row 5 – Numerical: 2013 Actual Reconciliting Items has been corrected. Notes – Further explanation and referencing has been added to Notes 1, 2 and 4.
L-02.2-1 Staff-009 Attachment 1	The attachment is being resubmitted as the last few lines of the original submission were cut-off.
L-03.1-20 VECC-005 Attachment 1, Table 5	The attachment is being resubmitted as the last few lines of the original submission were cut-off.
L-04.3-15 SEC-025	The response to part b of SEC Interrogatory #25 has been corrected.
L-06.1-1 Staff 97	Numerical: The estimated cost of first and second mini post-refurbishment planned outages has been corrected.
L-06.1-2 AMPCO-092	Line 36 – The words "and defueling operations" have been removed.
L-06.6-1 Staff-147	Part g – Numerical: The amount quoted for 2017, and as a result, the total over the 2017-2021 period has been corrected.
L-06.6-2 AMPCO-132	Part d – Interrogatory reference in the last line has been corrected.
L-06.6-2 AMPCO-145	Table 2 – Numerical: Table 2 was corrected. In OPG's original response the column for 2020 was missing and the numbers reported for 2021 actually corresponded to 2020.

Yours truly,

[Original signed by]

Barbara Reuber

cc: Carlton Mathias (OPG) via e-mail
Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail

ATTACHMENT 1 - TABLE OF EVIDENCE AMENDMENTS

EXHIBIT	TAB	SCHEDULE	ATTACHMENT	TITLE	FILED (F) UPDATED (U)	DATE
A1	3	3		Nuclear Rate Smoothing and Midterm Production Review	U1	2016-11-10
D2	1	3		Capital Projects – Nuclear Operations	U1	2016-11-10
D2	2	3		Major Work Bundle Structure and Contracts	U1	2016-11-10
F2	1	1		Business Planning and Benchmarking	U1	2016-11-10
F2	2	3		Pickering Extended Operations	U1	2016-11-10
F2	4	1		Outage OM&A	U1	2016-11-10
F2	6	1		OM&A Purchased Services – Nuclear Operations	U1	2016-11-10
F4	2	1		Taxes	U1	2016-11-10
F4	3	1		Compensation and Benefits	U1	2016-11-10
F4	4	1		Centrally Held Costs	U1	2016-11-10
G2	2	1		Bruce Generating Station – Revenues and Costs	U1	2016-11-10
I1	1	1		Summary of Nuclear Revenue Requirement and Revenue Deficiency	U1	2016-11-10
L	1.2	5		CCC-008	U1	2016-11-10
L	2.1	2	1	AMPCO-013	U1	2016-11-10
L	2.2	1	1	Staff-009	U1	2016-11-10
L	3.1	20	1	VECC-005	U1	2016-11-10
L	4.3	15		SEC-025	U1	2016-11-10
L	6.1	1		Staff-097	U1	2016-11-10
L	6.1	2		AMPCO-092	U1	2016-11-10
L	6.6	1		Staff-147	U1	2016-11-10
L	6.6	2		AMPCO-132	U1	2016-11-10
L	6.6	2		AMPCO-145	U1	2016-11-10

6) Customer Bill Impact: The four Customer Focus considerations discussed above all affect the short-term and long-term impact on customer bills. The magnitude of the customer bill impact over the full deferral and recovery period should be reasonable in the circumstances.

2.4 Rate Smoothing Alternatives

Ontario Regulation 53/05 requires the OEB to set smoothed annual payment amounts by deferring specific amounts of approved nuclear revenue requirement. In this application the OEB is setting a smoothing rate for the 2017 to 2021 period, and revenue requirement and production information for this period is required to do so. The amount of revenue requirement to be deferred each year is the net amount resulting from OEB decisions on the annual nuclear production forecasts, annual nuclear revenue requirements, and the rate of annual increase in nuclear base payment amounts. The revenue requirement and production forecasts[14] proposed in this application are summarized in Chart 1. Rate smoothing alternatives are provided at the end of this section.

Chart 1

Nuclear Revenue Requirement and Production

	2017	2018	2019	2020	2021	Total
Proposed Revenue Requirement ($M)	$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,489	$ 16,989
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38	188.33

Ontario Regulation 53/05 requires the OEB to authorize recovery of the balance in the RSDA over a period not to exceed ten years.[15] As the magnitude of the costs being deferred is in the billions of dollars, OPG's smoothing proposal assumes RSDA recovery over the maximum ten year period.

Since rates set for the 2017 to 2021 period will necessarily have implications for the rates set later in the deferral and recovery periods, an understanding of forecast nuclear costs and

[14] Production forecast details for Darlington and Pickering are provided in Ex E2-1-1 Table 1. Revenue Requirement values are net of stretch factor reductions, as presented in Ex. I1-3-1 Table 1.
[15] O. Reg. 53/05 section 6 (2), subparagraph 12 (iii).

period (i.e., approximately $120/MWh), and an estimated average monthly customer bill impact over the full deferral and recovery periods.

Chart 3
Smoothing Alternatives – Outcomes

2017 - 2021 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2022- 2026 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2027 - 2035 Rate Increase	(6.4)%	(3.4)%	(0.3)%	2.6%	5.4%
Peak Account Balance ($B)	$2.4	$3.5	$5.0	$6.9	$9.5
2017 - 2036 Total Interest ($B)	$0.7	$1.6	$3.0	$4.5	$5.9
Interest Cost / Deferred Revenues Ratio	0.2	0.5	0.8	0.9	0.9
FFO Interest Coverage > = 3* (2017-2021) / (2022-2026)	3.7 / 6.3	3.6 / 5.3	3.5 / 4.5	3.5 / 3.9	3.4 / 3.3
DEBT to EBITA < = 5.5* (2017-2021) / (2022-2026)	6.1 / 5.1	6.2 / 5.3	6.3 / 5.5	6.3 / 5.7	6.4 / 6.0
Transition Impact: 2037 Rate Change ($/MWh / %)	$26/MWh / 27%	$2/MWh / 2%	$(28)/MWh / (19%)	$(60)/MWh / (33%)	$95/MWh / (44%)
Average Bill Impact: 2017-2036 (%)	0.2%	0.3%	0.4%	0.6%	0.8%
Average Bill Impact: 2017-2036 ($ / month)	$0.24	$0.42	$0.65	$0.90	$1.16

*Weakest Ratio

2.5 Application of the Criteria and OPG's Proposal

Based on its assessment of the alternatives above, using the considerations described in section 2.3, OPG proposes an 11 per cent annual nuclear base rate increase for the 2017 to 2021 period. A discussion of the rationale OPG applied to evaluate each option for each of

Numbers may not add due to rounding.

Table 4
Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	89.9	(10.0)	79.9	(48.8)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	**Pickering NGS**	53.6	41.3	94.9	(26.2)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	**Nuclear Support Divisions**[1]	17.4	10.2	27.6	(1.6)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	**Subtotal**	160.8	41.6	202.4	(76.7)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	**Supplemental In-Service Forecast**[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	**Total Portfolio In-Service Forecast**	160.8	41.6	202.4	(76.7)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	**Minor Fixed Assets**	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	**Total In-Service Capital Additions**	180.7	31.9	212.6	(64.0)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Darlington NGS**	107.0	224.5	331.4	(150.1)	181.3	(29.4)	152.0	10.4	162.4	(102.4)	60.0
10	**Pickering NGS**	71.7	93.2	164.9	(78.9)	86.0	(70.2)	15.8	(13.0)	2.8	(2.8)	0.0
11	**Nuclear Support Divisions**[1]	3.1	13.9	17.1	(10.1)	6.9	(3.3)	3.6	(3.6)	0.0	0.0	0.0
12	**Subtotal**	181.8	331.6	513.4	(239.1)	274.3	(102.9)	171.4	(6.2)	165.2	(105.3)	60.0
13	**Supplemental In-Service Forecast**[2]	0.0	(47.4)	(47.4)	136.1	88.7	35.1	123.8	(68.8)	55.0	150.7	205.7
14	**Total Portfolio In-Service Forecast**	181.8	284.3	466.0	(103.0)	363.0	(67.7)	295.2	(75.0)	220.2	45.4	265.6
15	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	15.3
16	**Minor Fixed Assets**	22.3	8.7	31.0	(5.0)	26.0	(6.0)	20.0	(0.9)	19.1	0.4	19.5
17	**Total In-Service Capital Additions**	204.1	292.9	497.0	(108.0)	389.0	(73.7)	315.2	(75.9)	239.3	61.1	300.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
18	**Darlington NGS**	60.0	(21.3)	38.7
19	**Pickering NGS**	0.0	0.0	0.0
20	**Nuclear Support Divisions**[1]	0.0	0.0	0.0
21	**Subtotal**	60.0	(21.3)	38.7
22	**Supplemental In-Service Forecast**[2]	205.7	(48.0)	157.6
23	**Total Portfolio In-Service Forecast**	265.6	(69.3)	196.3
24	**Darlington New Fuel**	15.3	(15.3)	0.0
25	**Minor Fixed Assets**	19.5	(0.1)	19.3
26	**Total In-Service Capital Additions**	300.4	(84.8)	215.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

- Also for simplicity, the cost categories of OSM, Reimbursable Costs and Goods assume the increased costs all include any contractor markups, and any cost savings or overruns are excluded from the Fixed Fee incentives/ disincentives.
- the target cost for both the Definition Phase and Execution Phase Support Services and Equipment ("SS&E") are added to each of the Definition Phase and Execution Phase Target Costs respectively, and the Definition Phase and Execution Phase SS&E incentives and disincentives were calculated consistently with the Definition Phase and Execution Phase Target Costs. Under the contract, the Definition Phase and Execution Phase SS&E would be subject to its own neutral band and graded scale for incentives and disincentives.

- No schedule disincentives are applied.
- The numbers may not add due to rounding.

In the first scenario set out in Chart 4 below, the contractor achieves a 1 per cent cost savings. For the fixed price portions of work, there is no impact to OPG (Chart 4, lines 2, 5, 7 and 9). For the target cost portions of work, OPG shares in the contractor's cost savings as the contractor is reimbursed for only its actual costs incurred (Chart 4, lines 1 and 4), which are less than the negotiated target costs. As the 1 per cent cost savings fall within both the Definition Phase and Execution Phase neutral bands ($2.5M and $75M respectively), there is no cost incentive payment for coming in below the target (Chart 4, lines 3 and 6). OSM are paid at the actual costs.

Chart 4 - Illustrative Scenarios of RFR Target Pricing (Contractor 1% Cost Savings)

#	Category ($ Million)	Contract Costs (from table 3)	% Contractor Cost Savings = 1%				
			Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	183	(2)	0	(2)	183
2	Definition Phase Fixed Fee	74	73	(1)	(1)	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				0	0	0
4	Execution Phase Target Cost	1,667	1,650	(17)	0	(17)	1,650
5	Execution Phase Fixed Fee	492	487	(5)	(5)	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				0	0	0
7	Mock-up Fixed Price	38	38	(0)	(0)	0	38
8	Non-target Reimbursable Costs	6	6	(0)	0	(0)	6
9	Tooling Fixed Price	375	371	(4)	(4)	0	375
10	OSM	579	573	(6)	0	(6)	573
11	Goods	48	48	(0)	0	(0)	48
12	Total	3,464	3,429	(35)	(10)	(25)	3,439

In the second scenario set out below in Chart 5, the contractor achieves a 10 per cent cost savings. For the fixed price portions of work, there continues to be no impact to OPG (Chart 5, lines 2, 5, 7 and 9). For the target cost portions of work, OPG shares in the contractor's cost savings as the contractor is reimbursed for only its actual costs (Chart 5, lines 1 and 4). At 10 per cent cost savings, the savings for the Definition Phase Target Cost are $19M and fall outside the $2.5M neutral band for Definition Phase. As a result, an incentive payment of $3M applies. For the Execution Phase Target Cost, the savings are $167M and also falls outside the $75M Execution Phase neutral band. OPG pays the contractor a cost incentive for coming in below the target (Chart 5, lines 3 and 6). As the total demonstrates (Chart 5, line 12), the contractor is incented to come in below target cost in order to take advantage of the cost incentive payments, and OPG benefits from significant cost savings even after payment of the cost incentive. OSM and Goods are paid at actual costs and OPG retains those savings.

Chart 5 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Savings)

#	Category ($ Million)	Contract Costs (from table 3)	% Contractor Cost Savings = 10%				
			Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	167	(19)	0	(19)	167
2	Definition Phase Fixed Fee	74	66	(7)	(7)	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				(3)	3	3
4	Execution Phase Target Cost	1,667	1,500	(167)	0	(167)	1,500
5	Execution Phase Fixed Fee	492	443	(49)	(49)	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				(18)	18	18
7	Mock-up Fixed Price	38	34	(4)	(4)	0	38
8	Non-target Reimbursable Costs	6	5	(1)	0	(1)	5
9	Tooling Fixed Price	375	338	(38)	(38)	0	375
10	OSM	579	521	(58)	0	(58)	521
11	Goods	48	43	(5)	0	(5)	43
12	Total	3,464	3,117	(346)	(119)	(227)	3,237

In the third scenario, the contractor incurs a 1 per cent cost overrun. For the fixed price portions of work, there is no negative cost impact to OPG (Chart 6, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 6, lines 1 and 4). As the 1 per cent cost overrun falls inside both the Definition Phase and Execution Phase neutral bands ($2.5M and $75M respectively), there is no cost disincentive payment from the contractor for coming in above the target (Chart 6, lines 3 and 6). OSM is at actual cost and OPG pays the 1 per cent cost overrun.

Chart 6 - Illustrative Scenarios of RFR Target Pricing (Contractor 1% Cost Overrun)

			% Contractor Cost Overrun = 1%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	187	2	0	2	187
2	Definition Phase Fixed Fee	74	74	1	1	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				0	0	0
4	Execution Phase Target Cost	1,667	1,684	17	0	17	1,684
5	Execution Phase Fixed Fee	492	497	5	5	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				0	0	0
7	Mock-up Fixed Price	38	38	0	0	0	38
8	Non-target Reimbursable Costs	6	6	0	0	0	6
9	Tooling Fixed Price	375	379	4	4	0	375
10	OSM with Fee(estimate)	579	585	6	0	6	585
11	Goods with Fee(estimate)	48	48	0	0	0	48
12	Total	3,464	3,498	35	10	25	3,488

In the fourth scenario, the contractor incurs a 10 per cent cost overrun. For the fixed price portions of work, there continues to be no negative cost impact to OPG (Chart 7, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 7, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $19M (Chart 7, line 1), which is outside the $2.5M Definition Phase neutral band. As a result, the contractor must pay a disincentive payment of $3M to OPG. The 10 per cent cost overrun for the Execution Phase Target Cost is $167M (Chart 7, line 4) and also falls outside the $75M Execution Phase neutral band. As a result, the contractor must additionally pay OPG a disincentive payment of $18M for coming in above the target (Chart 7, lines 3 and 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

As the total line demonstrates (Chart 7, line 12), the pricing mechanisms and disincentives discourage the contractor from incurring cost overruns as it will not be paid for any cost overrun on fixed price portions of work, and it will also have to pay OPG cost disincentive payments (a specified percentage of its Fixed Fee portions of work, as described above) for overruns it incurs on target price portions of work that fall outside of the neutral band. Cost overruns outside of the neutral band therefore reduce the contractor's expected profits. Since the contractor's Fixed Fee was established as a percentage of the Execution Phase Target Cost, and contractor overheads increase in a cost overrun scenario, the contractor's lost profit includes both the disincentive payments and the loss associated with the requirement to pay incremental overheads not covered in the fixed fee.

Chart 7 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Overrun)

			% Contractor Cost Overrun = 10%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	204	19	0	19	204
2	Definition Phase Fixed Fee	74	81	7	7	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				3	(3)	(3)
4	Execution Phase Target Cost	1,667	1,834	167	0	167	1,834
5	Execution Phase Fixed Fee	492	541	49	49	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				18	(18)	(18)
7	Mock-up Fixed Price	38	42	4	4	0	38
8	Non-target Reimbursable Costs	6	7	1	0	1	7
9	Tooling Fixed Price	375	413	38	38	0	375
10	OSM with Fee(estimate)	579	637	58	0	58	637
11	Goods with Fee(estimate)	48	53	5	0	5	53
12	Total	3,464	3,810	346	119	227	3,690

OPG also conducted a rigorous vetting process to establish the Execution Phase Class 2 estimate for the RFR. The process included detailed review of the elements of the estimate by the project management team and a strategy to validate elements of the estimate and assess the gaps OPG identified in the original estimate submission. Further information on the vetting process is provided in Ex. D2-2-8.

Also discussed in Ex. D2-2-8, Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") were engaged by OPG to assess the process undertaken by OPG in developing the RQE. A copy of the BMcD/Modus report is provided in Ex. D2-2-8 Attachment 2. In their assessment, BMcD/Modus addresses the costs of the RFR contract and concludes that the results are appropriate:

Table 1
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

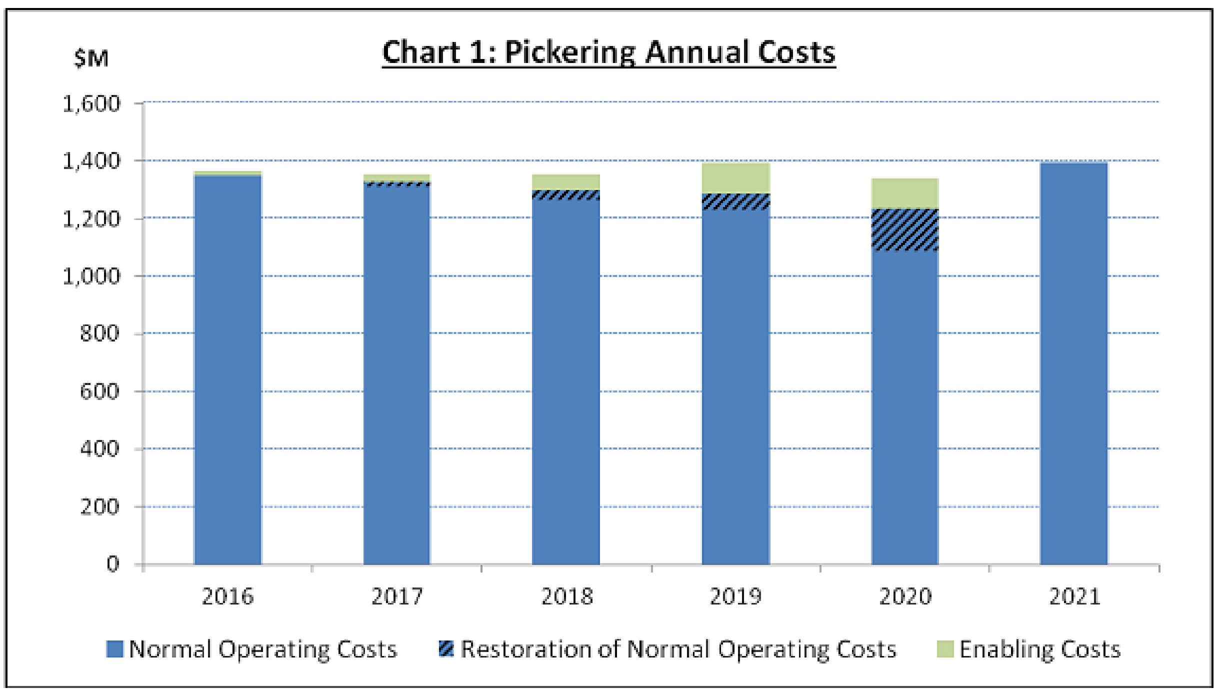
Notes:

1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.8M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.

2 Comprises centrally-held costs from Ex. F4-4-1 Table 3 and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

be undertaken over the test period. This work is comprised of enabling actions required to extend operations and secure the necessary CNSC approvals. In addition, funds necessary to support the plant's normal operating activities have been included over the 2016-2021 period. The cost of these activities would have previously been forecast to decline when the plant was scheduled to shutdown in 2020.

Chart 1 below shows the estimated costs to enable Extended Operations and operate Pickering in each year of the test period. While this exhibit discusses these costs, they are recovered primarily through the base, project and outage OM&A exhibits (Exhibits F2-2-1, F2-3-1 and F2-4-1, respectively) with the relatively smaller amount of capital expenditures for Pickering projects and minor fixed assets recovered through Ex. D2-1-2. Thus, there is no additional revenue requirement request associated with this exhibit.



3.3.1 Enabling Work and its Associated Cost

In advance of recommending Extended Operations, OPG completed an initial technical assessment of the Pickering units' continued ability to operate to the proposed shutdown

Table 3
Outage OM&A by Resource Type - Nuclear ($M)
Historic Years

Line No.	Division	Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Budget - Year Ending December 31, 2013								
	Nuclear Stations:								
1	Darlington NGS	0.0	13.3	25.8	0.6	21.1	35.8	0.2	96.9
2	Pickering NGS	0.0	10.2	27.3	0.0	20.9	31.3	0.1	89.7
3	Pickering Continued Operations	0.0	0.6	1.1	0.0	5.3	1.3	0.0	8.3
4	**Total Stations**	0.0	24.1	54.2	0.6	47.3	68.4	0.3	194.9
5	**Nuclear Support Divisions**	23.1	10.2	25.1	27.2	10.7	18.2	1.5	116.1
6	**Total Outage OM&A**	23.1	34.4	79.3	27.8	58.0	86.6	1.8	311.0
	Actual - Year Ending December 31, 2013								
	Nuclear Stations:								
7	Darlington NGS	0.0	12.4	30.3	0.0	23.5	28.4	1.0	95.7
8	Pickering NGS	0.0	5.1	25.2	0.0	21.6	25.2	0.6	77.6
9	Pickering Continued Operations	0.0	0.4	2.1	0.0	5.9	1.8	0.0	10.2
10	**Total Stations**	0.0	18.0	57.6	0.0	51.0	55.4	1.6	183.5
11	**Nuclear Support Divisions[1]**	16.8	10.8	28.6	15.6	10.2	11.7	0.2	94.0
12	**Total Outage OM&A**	16.8	28.7	86.2	15.6	61.2	67.1	1.8	277.5
	OEB Approved[2] - Year Ending December 31, 2014								
	Nuclear Stations:								
13	Darlington NGS	0.0	10.5	14.0	2.0	14.0	25.4	0.0	65.9
14	Pickering NGS	0.0	11.0	29.4	0.0	22.1	37.6	0.0	100.1
15	Pickering Continued Operations	0.0	0.4	1.2	0.0	3.8	0.8	0.0	6.2
16	**Total Stations**	0.0	21.9	44.6	2.0	39.9	63.9	0.0	172.3
17	**Nuclear Support Divisions**	21.0	8.6	19.6	18.2	9.4	12.5	1.1	90.4
18	**Total Outage OM&A**	21.0	30.5	64.3	20.2	49.2	76.4	1.1	262.7
	Actual - Year Ending December 31, 2014								
	Nuclear Stations:								
19	Darlington NGS	0.0	7.7	13.8	0.4	13.0	20.9	0.6	56.4
20	Pickering NGS	0.0	8.7	20.5	0.1	19.1	33.9	0.8	83.0
21	Pickering Continued Operations	0.0	0.2	0.8	0.0	2.1	0.6	0.0	3.7
22	**Total Stations**	0.0	16.6	35.1	0.5	34.2	55.4	1.4	143.1
23	**Nuclear Support Divisions[1]**	18.6	10.2	15.8	16.0	8.2	9.3	0.1	78.2
24	**Total Outage OM&A**	18.6	26.8	50.8	16.5	42.4	64.7	1.5	221.3
	OEB Approved[3] - Year Ending December 31, 2015								
	Nuclear Stations:								
25	Darlington NGS	0.0	10.4	24.9	6.7	27.3	56.9	0.0	126.2
26	Pickering NGS	0.0	8.6	28.1	0.0	19.2	38.3	0.0	94.3
27	Pickering Continued Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Total Stations**	0.0	19.0	53.0	6.7	46.6	95.2	0.0	220.5
29	**Nuclear Support Divisions**	25.3	12.4	24.4	20.9	7.8	18.4	1.1	110.3
30	**Total Outage OM&A**	25.3	31.4	77.4	27.6	54.3	113.6	1.1	330.7
	Actual - Year Ending December 31, 2015								
	Nuclear Stations:								
31	Darlington NGS	0.0	10.5	18.2	0.7	27.0	65.9	1.6	123.8
32	Pickering NGS	0.0	6.4	19.6	0.2	23.7	46.4	1.1	97.4
33	Pickering Continued Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**Total Stations**	0.0	16.8	37.8	0.8	50.8	112.3	2.6	221.2
36	**Nuclear Support Divisions**	20.0	13.7	15.8	25.0	6.9	11.0	0.1	92.5
37	**Total Outage OM&A**	20.0	30.5	53.7	25.8	57.6	123.3	2.7	313.7

Notes:
1 Nuclear Support Divisions includes Outage OM&A expenditures for Pickering Continued Operations of $10.5M for 2013 Actual and $10.7M for 2014 Actual.
2 As OEB Approved adjustments shown on Ex. F2-1-1 Table 2 were made at the aggregate Nuclear OM&A level, the figures presented here are 2014 Plan (from EB-2013-0321) rather than 2014 OEB Approved.
3 As OEB Approved adjustments shown on Ex. F2-1-1 Table 2 were made at the aggregate Nuclear OM&A level, the figures presented here are 2015 Plan (from EB-2013-0321) rather than 2015 OEB Approved.

OM&A PURCHASED SERVICES
NUCLEAR OPERATIONS

1.0 PURPOSE

This evidence presents the purchases of OM&A services for nuclear operations (excluding Darlington Refurbishment) that meet the threshold of one per cent of the OM&A expense before taxes, consistent with OEB filing guidelines.

2.0 OVERVIEW

This evidence supports the approval sought for the purchased services portion of nuclear OM&A costs. An overview of OPG's procurement process which is applicable to the nuclear facilities is presented in Ex. F3-3-1.

The nuclear operations OM&A expense before taxes is equal to the sum of nuclear base, project and outage OM&A. This sum is $1,718.9M in 2017, $1,728.9M in 2018, $1,763.8M in 2019, $1,760.9M in 2020, and $1,671.6M in 2021 as presented in Ex. F2-1-1 Table 1. For the nuclear facilities the threshold of one per cent of the operations OM&A expense before taxes is, therefore approximately $17M.

Information on vendor contracts for nuclear operations purchased services for nuclear base, outage and project OM&A expenditures at or above the $17M threshold for 2013-2015 is presented in Chart 1.

Total purchases for the vendors listed in Chart 1 are $136.2M in 2013, $129.4M in 2014, and $166.7M in 2015.

Numbers may not add due to rounding.

Table 2
Taxes - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Income Tax**[1,2]	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
	Property Tax:									
2	**Darlington NGS**	8.7	8.3	8.3	8.5	9.2	9.4	9.6	9.9	10.7
3	**Pickering NGS**	4.9	4.9	4.9	5.0	5.4	5.5	5.7	5.8	6.3
4	**Sub-total**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
5	**Total**	(62.8)	(48.3)	(18.6)	(5.2)	(3.8)	(3.5)	(3.1)	66.9	68.7

Notes:

1 The income tax expense is calculated on a combined basis for OPG's prescribed facilities for the years 2013 to 2016. As described in Ex. F4-2-1, the resulting expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business's taxable income, and for SR&ED ITCs, on the basis of the underlying expenditures.

2 Amounts for 2017 to 2021 are from Ex. F4-2-1 Table 3a, line 26.

Table 4
Reconciliation of OPG's Tax Returns to Regulatory Income Tax Calculation for Prescribed Facilities ($M)
Year Ending December 31, 2014

		2014 Tax Returns					Adjustments		(e) - (f) - (g)
Line		OPG		(a) + (b)		(c) - (d)	Bruce	Other	Regulatory
No.	Particulars	Inc.	Subsidiaries	Total[1]	Unregulated	Regulated[2]	Lease[3]	Adjustments[4]	Tax Calc'n[5]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Determination of Taxable Income								
1	**Earnings Before Tax**	793.3	(86.9)	706.4	92.6	613.8	135.6	206.6	271.6
	Additions for Tax Purposes:								
2	**Depreciation and Amortization**	454.5	103.3	557.8	29.4	528.4	104.0	28.6	395.8
3	**Nuclear Waste Management Expenses (incl Accretion Expense)**	967.1	0.0	967.1	0.0	967.1	449.4	486.4	31.3
4	**Receipts from Nuclear Segregated Funds**	76.3	0.0	76.3	0.0	76.3	34.0	0.0	42.3
5	**Pension and OPEB Accrual**	752.8	0.0	752.8	78.6	674.2	0.0	289.4	384.8
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	49.9	0.0	49.9	0.0	49.9	0.0	49.9	0.0
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues**	41.9	0.0	41.9	0.0	41.9	0.0	0.0	41.9
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**	(14.1)	0.0	(14.1)	0.0	(14.1)	0.0	(1.7)	(12.4)
9	**Regulatory Asset Amortization - Tax Loss Variance Account**	120.6	0.0	120.6	0.0	120.6	0.0	120.6	0.0
10	**Regulatory Asset and Liability Amortization - Other Variance and**	84.3	0.0	84.3	0.0	84.3	0.0	84.3	0.0
11	**Adjustment Related to Financing Cost for Nuclear Liabilities**	0.0	0.0	0.0	0.0	0.0	0.0	(75.2)	75.2
12	**Taxable SR&ED Investment Tax Credits**	20.2	0.0	20.2	1.0	19.2	0.0	0.0	19.2
13	**Disallowance of Niagara Tunnel Project Expenditures**	77.2	0.0	77.2	0.0	77.2	0.0	0.0	77.2
14	**Other**	117.6	0.0	117.6	16.6	101.1	49.2	12.4	39.4
15	**Total Additions**	2,748.3	103.3	2,851.6	125.6	2,726.1	636.6	994.7	1,094.7
	Deductions for Tax Purposes:								
16	**CCA**	495.6	5.1	500.7	88.3	412.4	5.3	2.9	404.3
17	**Cash Expenditures for Nuclear Waste Mngmt & Decommissioning and Facilities Removal**	209.1	0.0	209.1	0.0	209.1	100.1	0.0	109.1
18	**Contributions to and Earnings on Nuclear Segregated Funds**	959.6	0.0	959.6	0.0	959.6	380.5	409.0	170.1
19	**Pension Plan Contributions**	360.0	0.0	360.0	37.5	322.5	0.0	(0.0)	322.5
20	**OPEB/SPP Payments**	108.5	0.0	108.5	11.5	97.0	0.0	0.0	97.0
21	**Reversal of Nuclear Liability Deferral Account Additions**	66.9	0.0	66.9	0.0	66.9	0.0	66.9	0.0
22	**Reversal of Pension and OPEB Deferral and Variance Account Additions**	296.0	0.0	296.0	0.0	296.0	0.0	296.0	0.0
23	**Reversal of Regulatory Asset and Liability - Other Deferral and Variance Account Additions**	104.7	0.0	104.7	0.0	104.7	0.0	104.7	0.0
24	**Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account**	0.0	0.0		0.0	0.0	0.0	(55.0)	55.0
25	**Deductible SR&ED Qualifying Expenditures**	180.6	0.0	180.6	5.8	174.8	0.0	0.0	174.8
26	**Construction In Progress Interest Capitalized**	61.0	0.0	61.0	6.7	54.3	0.0	54.3	0.0
27	**Other**	307.2	0.0	307.2	239.1	68.1	58.9	(1.7)	11.0
28	**Total Deductions**	3,149.2	5.1	3,154.3	388.9	2,765.4	544.7	877.0	1,343.7
29	**Taxable Income** (line 1 + line 15 - line 28)	392.4	11.3	403.7	(170.7)	574.5	227.5	324.3	22.7

Notes:

1 Represents the consolidated OPG amounts. Earnings Before Tax at line 1 are as reported in OPG's 2014 audited consolidated financial statements and found at Ex. A2-1-1, Att. 2, p. 111.

2 Represents amounts for OPG's "regulated" segments as reported in accordance with generally accepted accounting principles in OPG's audited consolidated financial statements.

3 Represents Bruce Lease net revenues included in col. (e). Bruce Lease earnings before tax at line 1 are as per Ex. G2-2-1 Table 7, col. (b), line 1 and taxable income at line 34 as per Ex. G2-2-1 Table 7, col. (b), line 17

4 Represents items of income and expense reflected in OPG's income tax returns that do not form part of the regulatory income tax claculations as per OEB-approved methodology, and vice versa, as well as as line item presentation differenes bewteen the tax returns and the regulatory income tax calculation that do not impact taxable income

5 Amounts are as shown in Ex. F4-2-1 Table 3, col. (b).

of staffing levels and the collective bargaining agreements that cover approximately 90 per cent of OPG's employees.

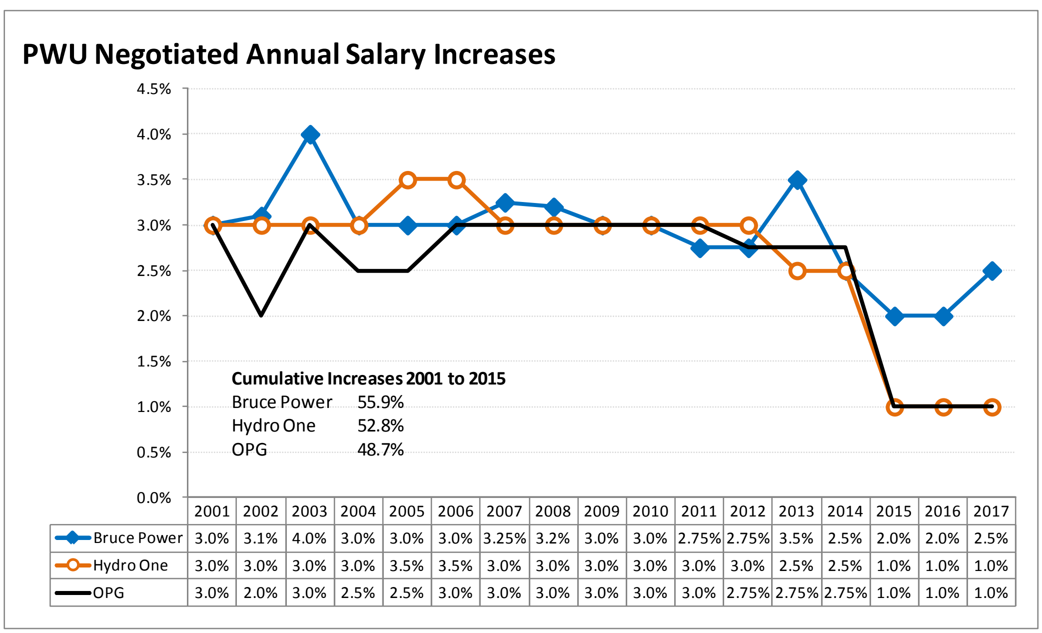
Unionized Salaries:

OPG is legally bound by its collective agreements. These agreements govern salary increases, cost of living adjustments, and progressions through established salary ranges.

OPG, with the direct involvement and support of the Government, negotiated agreements with both the PWU and Society in 2015 that will keep wage escalation below inflation. Both agreements provide for a one per cent escalation increase each year and cover a three year period, running from April 1, 2015 to March 31, 2018 for the PWU and from January 1, 2016 to December 31, 2018 for the Society.

Until recently, typical union salary increases have tended to be between 2 per cent and 3 per cent per year for both OPG and other large companies within the electricity sector in Ontario, as shown in Figures 5 to 8.

Figure 5



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Bruce Power	3.0%	3.1%	4.0%	3.0%	3.0%	3.0%	3.25%	3.2%	3.0%	3.0%	2.75%	2.75%	3.5%	2.5%	2.0%	2.0%	2.5%
Hydro One	3.0%	3.0%	3.0%	3.0%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	1.0%	1.0%	1.0%
OPG	3.0%	2.0%	3.0%	2.5%	2.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	2.75%	1.0%	1.0%	1.0%

4.2 Trends and Variances

OPG-wide insurance costs for the nuclear facilities are generally stable over the test period, with period-over-period fluctuations and budget-to-actual variances in historical and bridge periods attributable mainly to actual and assumed insurance premium increases and changes related to appraised asset replacement cost values.

The main trend in the planned increases in nuclear insurance costs over the bridge and test periods are increased premiums starting in 2016, due to higher statutory nuclear liability insurance limits that will be phased in over four years in accordance with the provisions of the new federal legislation. As noted in Ex. A1-6-1, the higher limits will result once the *Nuclear Liability and Compensation Act*, which received Royal Assent in February 2015, is in force and replaces the 1976 *Nuclear Liability Act*.

5.0 PERFORMANCE INCENTIVES

5.1 Description

These costs are for the pay-at-risk program that compensates OPG's Management (i.e. non-unionized) employees based on the achievement of corporate and individual performance objectives. The costs continue to be attributed to the business units based on the distribution of past performance incentive payments.

5.2 Trends and Variances

Performance incentive costs are projected assuming target performance is achieved and are generally stable over the 2016-2021 period. The costs fluctuate in the historical period, reflecting variations in actual corporate performance. The 2014 costs were close to the OEB-approved amount as the impact of exceeding target corporate performance was largely offset by lower staff levels. The 2015 costs were below the OEB-approved amount chiefly due to lower staff levels. OPG's Management compensation, including the pay-at-risk program, is discussed in Ex. F4-3-1.

Table 8
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2017, 2018, 2019, 2020, and 2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Taxable Income						
1	**Earnings (Loss) Before Tax**	1	(92.9)	(103.8)	(114.5)	(109.4)	(124.1)
	Additions for Tax Purposes - Temporary Differences:						
2	**Base Rent Accrual**		65.5	67.2	(9.1)	(9.1)	(9.1)
3	**Depreciation**		100.8	100.8	100.8	100.7	100.7
4	**Accretion**		531.4	552.4	573.9	595.6	617.8
5	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		73.5	73.5	77.3	84.6	68.3
6	**Receipts from Nuclear Segregated Funds**		66.1	51.7	74.5	59.4	72.8
7	**Other**		3.4	2.2	2.8	2.3	2.3
8	**Total Additions - Temporary Differences**		840.7	847.8	820.1	833.5	852.7
	Deductions for Tax Purposes - Permanent Differences:						
9	**Deferred Rent Revenue**		14.2	14.2	0.0	0.0	0.0
	Deductions for Tax Purposes - Temporary Differences:						
10	**CCA**		6.3	6.0	5.7	5.6	5.5
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		172.1	186.7	207.9	237.0	231.5
12	**Contributions to Nuclear Segregated Funds**		6.8	18.1	22.6	97.5	97.5
13	**Earnings (Losses) on Nuclear Segregated Funds**		395.7	413.7	432.8	454.8	479.8
14	**Total Deductions - Temporary Differences**		580.9	624.6	669.1	794.8	814.2
15	**Taxable Income/(Loss) Before Loss Carry-Over**		152.7	105.1	36.6	(70.8)	(85.7)
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over**	2	152.7	105.1	36.6	(70.8)	(85.7)
	Determination of Current Income Taxes						
18	**Taxable Income After Loss Carry-Over**		152.7	105.1	36.6	(70.8)	(85.7)
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current**	2	38.2	26.3	9.1	(17.7)	(21.4)
	Determination of Deferred Income Taxes						
21	**Total Net Temporary Differences** (line 8 - line 14)		259.8	223.1	151.1	38.7	38.4
22	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%
23	**Deferred Income Taxes**	3	(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
24	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0
25	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
26	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
27	**Deferred Income Tax - Total** (line 23 + line 26)		(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
	Income Tax Rate - Current						
28	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
29	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
30	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Deferred						
31	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
33	**Total Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 11 and Total Costs Before Income Tax in Ex. G2-2-1, Table 5, Line 8 for each corresponding year.

2 The benefit of carrying back the 2020 and 2021 tax losses to 2017 and 2018, respectively, would reduce the current income tax expense reported for 2020 and 2021, respectively, in accordance with GAAP for non-regulated businesses. The forecast income tax expense for 2020 and 2021 is presented on this basis.

3 Effective 2015, OPG adopted US GAAP changes that require entities to present deferred income taxes as long term.

Table 2
Comparison of Revenue Requirement to OEB Approved - Nuclear ($M)
Years Ending December 31, 2014 through 2021

Line No.	Description	Note	OEB Approved[1] 2014	OEB Approved[1] 2015	Actual 2014	Actual 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
			(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Total Cost of Capital**	2	233.5	231.4	59.8	(103.8)	(93.9)	273.9	278.2	270.1	542.1	571.5
	Expenses:											
2	**OM&A**	3	2,085.4	2,166.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
3	**Fuel**	4	268.6	262.6	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
4	**Depreciation & Amortization**	5	273.7	288.5	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
5	**Property Tax**	6	15.9	16.4	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
6	**Total Expenses**		2,643.6	2,733.9	2,867.7	3,059.6	2,998.1	2,900.0	2,942.8	2,980.3	3,136.7	2,816.5
	Less:											
	Other Revenues											
7	**Bruce Lease Revenues Net of Direct Costs**	7	39.7	40.6	71.7	7.1	(66.0)	(66.1)	(74.3)	(85.9)	(82.1)	(93.1)
8	**Ancillary and Other Revenue**	8	37.6	37.6	31.2	33.2	24.1	31.7	22.0	22.7	22.2	22.9
9	**Total Other Revenues**		77.3	78.2	102.9	40.3	(41.9)	(34.5)	(52.4)	(63.2)	(59.9)	(70.2)
10	**Income Tax**	6	(9.4)	(9.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
11	**Revenue Requirement**		2,790.4	2,877.6	2,763.1	2,883.7	2,927.5	3,189.9	3,255.0	3,295.1	3,790.0	3,509.8
	(line 1 + line 6 - line 9 + line 10)											
12	**Forecast Production (TWh)**	9	49.0	46.6	48.1	44.5	46.8	38.1	38.5	39.0	37.4	35.4

Notes:
1. From EB-2013-0321 Payment Amounts Order, Appendix A, Table 3, except forecast production which is from Appendix A, Table 4.
2. Actuals and Forecast: Nuclear portion of totals from Ex. C1-1-1 Tables 1 through 7 (col. (d)).
   Cost of Capital is allocated to nuclear operations using rate base financed by capital structure, except for Return on Equity from 2014 to 2016 which is determined relative to taxable income for the Nuclear Business Unit
3. Actuals and Forecast from Ex. F2-1-1 Table 1, line 11. 2014 to 2016 amounts are reflected on an accrual basis for Pension and OPEB. 2017 to 2021 pension and OPEB amounts are reflected on a cash basis.
4. Actuals and Forecast from Ex. F2-5-1 Table 1.
5. Actuals and Forecast from Ex. F4-1-1 Table 2.
6. Actuals and Forecast from Ex. F4-2-1 Table 2.
7. Actuals and Forecast from Ex. G2-2-1 Table 1.
8. Actuals and Forecast from Ex. G2-1-1 Table 1.
   Other Revenues included in the determination of the Nuclear revenue requirement are adjusted for sharing of 50 percent of net revenue from sales of heavy water per the OEB Decision in EB-2010-0008, per Ex. G2-1-2 Table 1, Note 2.
9. Actuals and Forecast from Ex. E2-1-1 Table 1.

CCC Interrogatory #8

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions that impact the nuclear facilities appropriate?

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 4, p. 3
With respect to OPG's asset management and project review process there is reference to the post implementation review process (PIR) which is an appraisal process designed to evaluate whether planned results of a given investment have been met following completion. It further states that the two main objectives of the PIR process are to verify whether the benefits stated in the project business case were realized, and to capture the lessons learned from each project so they can be applied to improve future projects and other investment decisions.

a. Please provide an example of a PIR that followed a simplified format and one that followed a comprehensive format;

b. Was a PIR undertaken for the Niagara Tunnel Project? If not why not? If so, please provide it;

c. How many projects are subject to a PIR appraisal each year?

Response

Attachment 1 provides an example of a Post Implementation Review (PIR) that followed a simplified format. Attachment 2 (which contains confidential content as marked) provides an example of a PIR that followed a comprehensive format.

a. Yes. The PIR for the Niagara Tunnel Project is currently undergoing final review and approval. OPG will update this response to provide a copy when it is approved.

b. On average over 2014 to 2015, OPG's nuclear business conducted about 20 PIRs per year.

Numbers may not add due to rounding

Table 1
Nuclear In-service Capital Additions* ($M)

	2010		2011			2012			2013		2014			2015		
	Budget	Actual	Plan	Board Approved	Actual	Plan	Board Approved	Actual	Budget	Actual	Plan	Board Approved	Actual	Plan	Board Approved	Actual
Nuclear Operations Capital Projects[1]	191.5	249.0	175.5	175.5	103.2	187.6	187.6	131.9	180.7	**212.6**	158.3	158.3	148.6	141.7	**207.7**	204.1
Darlington Refurbishment Program[2]	-	-	-	-	-	-	-	5.0	104.2	99.2	18.7	18.7	43.5	209.4	**143.4**	147.1
Support Services Capital Projects (Nuclear portion)[3]	8.8	4.7	8.0	8.0	12.0	18.3	18.3	15.2	8.0	3.4	2.4	2.4	1.8	7.0	7.0	2.9
Nuclear In-service Capital Additions Reported in Ex. D2	200.2	253.7	183.4	183.4	115.2	205.9	205.8	152.2	293.0	315.1	179.4	179.4	193.8	358.2	358.2	354.1
Reconciliting Items[4]	-	22.8	-	-	4.5	-	-	1.3	-	**1.0**	-	-	(8.7)	-	-	7.1
Total Nuclear Capital In-service Additions, excl. ARC[5]	**200.2**	**276.5**	**183.4**	**183.4**	**119.7**	**205.9**	**205.8**	**153.5**	**293.0**	**316.1**	**179.4**	**179.4**	**185.1**	**358.2**	**358.2**	**361.2**

Notes:

1 2010 to 2012 amounts are as shown at EB-2013-0321 Ex. D2-1-3, Table 4, line 8 and 16. 2010 to 2012 budget/plan and Board-approved amounts also are as shown at EB-2010-0008 Ex. B1-1-1, Chart 1.
2013 is as previously provided in EB-2013-0321 Ex. L4.7-17 SEC-50 Attachment 1, Table 4, line 16. 2014 and 2015 amounts are as shown at EB-2016-0152 Ex. D2-1-3, Table 4, line 8. 2013 to 2015 budget/plan and Board-approved amounts also are as shown at EB-2013-0321 Ex. B1-1-1, Chart 1, as adjusted to reflect reclassification of certain projects to Nuclear Operations from Darlington Refurbishment Program discussed in Ex. D2-2-10 Section 2.2.4 and Ex. L-4.3-1 Staff-71.

2 2010 to 2012 amounts are as shown at EB-2013-0321 Ex. D2-2-1, Table 6, line 9.
2013 to 2015 amounts are as shown at EB-2016-0152 Ex. D2-2-10, Table 5, line 6. 2013 to 2015 budget/plan and Board-approved amounts also are as shown at EB-2013-0321 Ex. B1-1-1, Chart 1, as adjusted to reflect reclassification of certain projects from Darlington Refurbishment Program to Nuclear Operations discussed in Ex. D2-2-10 Section 2.2.4 and Ex. L-4.3-1 Staff-71.

3 2010 to 2012 budget/plan and Board-approved amounts are as shown at EB-2010-0008 Ex. B1-1-1, Chart 1.
2013 to 2015 actual amounts are as shown at EB-2016-0152 Ex. L-6.9-1 Staff-183, Table 1.

4 2010 and 2011 actual amounts are primarily as explained at EB-2013-0321 Ex. B3-3-1 Table 1, Note 1.
2013 to 2015 actual amounts are explained in Ex. L-2.1-1 Staff-007.

5 2010 to 2012 actual amounts are as shown at EB-2013-0321 Ex. B3-3-1, Table 1, col. (b), lines 4, 10, and 16. 2010 to 2012 budget/plan and Board-approved amounts are as shown at EB-2010-0008 Ex. B3-3-1, Table 2, col. (b), lines 6, 12 and 18, adjusted to remove additions for proposed Darlington Refurbishment CWIP treatment of $105.2M and $255.8M in 2011 and 2012, respectively.
2013 to 2015 actual amounts are as shown at EB-2016-0152 Ex. B3-3-1, Table 1, col. (b), lines 5, 12 and 19. 2013 to 2015 budget/plan and Board-approved amounts are as shown at EB-2013-0321 Ex. B3-3-1, Table 2, col. (b), lines 4, 10 and 16.

Numbers may not add due to rounding

DRP projects wholly or partially in service in the test period ($millions)	Final In service year	Partial In-Service Years	Total Project Cost	Actual Amount in Rate Base[1]				Planned Amount in Rate Base[1]						Actual Depreciation[2]				Planned Depreciation in Revenue Requirement[2]						Amount Recorded in CRVA in 2015 *[3]
				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Darlington Energy Complex	2013		105.4	-	46.1	77.8	75.1	71.9	68.7	65.0	61.3	57.6	53.9	-	2.0	3.6	3.7	3.7	3.7	3.7	3.7	3.7	3.7	0.3
Water and Sewer Project	2015	2012, 2013	57.7	2.5	12.7	31.6	41.8	42.0	42.1	40.4	38.7	37.0	35.3	0.0	0.2	0.9	1.6	1.7	1.7	1.7	1.7	1.7	1.7	2.9
Heavy Water Storage & Drum Handling Facility	2017	2014	381.1	-	-	7.3	14.3	13.9	254.2	367.4	356.8	346.1	335.4	-	-	0.1	0.4	0.4	6.8	10.7	10.7	10.7	10.7	0.1
Electrical Power Distribution System	2015	2013	20.8	-	1.3	2.6	10.1	18.7	19.6	19.2	18.8	18.4	18.1	-	0.0	0.1	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.7
Powerhouse Steam Venting System	2015		5.6	-	-	-	2.6	5.3	5.4	5.3	5.1	5.0	4.8	-	-	-	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Third Emergency Power Generator Project	2016	2015	120.4	-	-	-	4.8	31.2	112.5	109.3	106.1	103.0	99.8	-	-	-	0.1	0.9	3.2	3.2	3.2	3.2	3.2	(0.5)
Containment Filtered Venting System	2016		80.3	-	-	-	-	29.6	78.4	76.5	74.3	72.0	69.8	-	-	-	-	0.8	2.2	2.2	2.2	2.2	2.2	-
Retube Feeder Replacement Island Support Annex	2015		40.7	-	-	-	0.9	21.4	40.5	39.4	38.3	37.1	36.0	-	-	-	0.0	1.0	1.1	1.1	1.1	1.1	1.1	0.1
Refurbishment Project Office	2016	2015	99.9	-	-	-	28.8	96.1	97.2	94.4	91.7	88.9	86.2	-	-	-	0.6	2.7	2.8	2.8	2.8	2.8	2.8	3.2
R&FR - Tooling for Removal Activities	2016		87.0	-	-	-	-	53.7	84.4	82.0	79.6	77.3	74.9	-	-	-	-	1.5	2.4	2.4	2.4	2.4	2.4	-
Shield Tank Overpressure Protection	2017	2016	13.5	-	-	-	-	3.4	10.1	13.4	13.1	12.7	12.4	-	-	-	-	0.1	0.3	0.4	0.4	0.4	0.4	-
Emergency Service Water Buried Services	2015		14.6	-	-	-	6.6	13.7	13.9	13.5	13.1	12.7	12.4	-	-	-	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.7
Darlington Refurbishment - Unit 2	2020		4,800.2	-	-	-	-	-	-	-	-	4,127.1	4,597.5	-	-	-	-	-	-	-	-	128.9	147.3	-
Other Miscellaneous Projects	Various		45.7	-	-	2.1	**7.7**	18.1	25.2	29.3	32.7	36.3	39.8	-	-	0.0	0.3	0.5	0.7	0.9	1.0	1.2	1.3	(1.8)
TOTAL			**5,872.9**	**2.5**	**60.2**	**121.2**	**192.6**	**419.1**	**852.3**	**955.2**	**929.7**	**5,031.4**	**5,476.2**	**0.0**	**2.3**	**4.7**	**7.0**	**14.1**	**25.8**	**29.9**	**30.0**	**159.1**	**177.6**	**5.9**

***** *Note: The Capacity Refurbishment Variance Account (CRVA) records variances between actual capital and non capital and firm capital commitment incurred for the DRP and the corresponding forecasts reflected in the revenue requirement approved by the OEB.*
Excludes certain projects reclassified from DRP to Nuclear Operation subsequent to the conclusion of EB-2013-0321 as further discussed in Ex. L-04.3-1 Staff 071

[1] Total net plant rate base amounts are as shown at Ex. B3-1-1 Table 1, lines 2, 9, and 16.

[2] Total depreciation as shown at Ex. F4-1-1 Table 2, line 2.

[3] Amounts represent CRVA additions recorded during 2015, which OPG seeks to clear in this application. Per the EB-2014-0370 Payment Amounts Order, account additions recorded prior to 2015 are scheduled to be recovered by December 31, 2016. Total 2015 addition shown are as per Ex. H1-1-1 Table 11: line 22 + line 25 + (sum of line 25 and ROE component of cost of capital variance at line 22) x 25% / (1-25%). Amounts do not reflect CCA variances, as CCA is claimed for all eligible DRP expenditures. For ease of reconciliation, the EB-2013-0321 Ex. N1 Impact Statement (Ex. N1) Adjustment at Ex. H1-1-1 Table 11, line 34 is also excluded. Positive amounts are recoverable from ratepayers; negative amounts are credited to ratepayers.

Numbers may not add due to rounding.

Table 5
Nuclear Portion of Total Rate Base

Line No.		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Hydro ($B)[1]	4.0	4.0	3.9	3.9	3.8	3.8	3.8	3.7	4.8	7.5	7.5	7.4	7.5	7.5	7.5	7.6	7.7
2	Nuclear ($B)[2,3]	2.9	3.0	3.5	2.5	2.3	2.4	2.4	2.3	2.3	2.3	2.3	2.7	3.3	3.5	3.5	7.5	8.0
3	Total ($B)	6.9	7.0	7.4	6.4	6.1	6.2	6.1	6.0	7.1	9.9	9.8	10.2	10.8	11.0	10.9	15.1	15.6
4	Nuclear Proportion of Total Rate Base (%)	42%	43%	47%	39%	37%	39%	39%	38%	32%	24%	24%	27%	31%	32%	32%	50%	51%

Notes
1 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 1
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 1
2010-2012 from EB-2013-0321 Ex. B1-1-1 Table 1
2 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 2
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 2, less UNL/ARC from Ex. C1-1-1 Tables 5 and 4 respectively
2010-2012 from EB-2013-0321 Ex. B3-2-1 Table 1 line 1
2013-2021 from EB-2016-0152 Ex. B3-2-1 Table 1 line 1, 4, and 7
3 For 2008 - 2021 Nuclear amounts do not include the lesser of unamortized asset retirement costs (“ARC”) or unfunded nuclear liabilities (“UNL”). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG’s rate base that does not include the lesser of ARC or UNL.

SEC Interrogatory #25

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
D2/2/3]
For each work bundle, please provide:
a. A detailed breakdown of the costs.

b. A copy of the estimate summary report or similarly named document (note: SEC understands from OPG that for each work bundle there is a detailed summary report of the contract cost final estimates).

Response

a) and b)

Please refer to Attachment 1. Attachment 1 contains confidential information.

Board Staff Interrogatory #97

Issue Number: 6.1
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

Interrogatory

Reference:
Ref: Exh F2-4-1 page 1
Ref: Exh E2-1-1 page 3
The evidence at Exh F2-4-1 states that, "Darlington Unit 2 is scheduled to return to service in February 2020 following refurbishment. OPG has scheduled two post refurbishment mini planned outages to address any issues expected to arise after the major refurbishment is complete and the unit has resumed operations."

The evidence at Exh E2-1-1 states that, "The need for these post-refurbishment outages is based on operating experience at other nuclear facilities that underwent major refurbishment."

What is the cost of each of the mini planned Darlington Unit 2 outages?

Response

The estimated cost of the first mini post-refurbishment planned outage is $12.8M and the second $8.2M. The second mini-outage is estimated to cost less due to the shorter duration and expected smaller scope.

AMPCO Interrogatory #92

Issue Number: 6.1
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

Interrogatory

Reference:
Ref: D2-2-8 Attachment 4 Page 27

a) Please quantify the % of costs associated with the full time operation of Darlington that remains during the test period by year and show the calculation.

Response

Chart 1 compares the Darlington operating costs in the test period to 2015 actual operating costs. Darlington operating costs reflect amounts shown in L-6.2-15 SEC-63 part (b), Chart 1 for Stations and Nuclear Support for 2017-2021.

Chart 1

Line No.	($M)	2015	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Darlington Operating Costs	694.6	723.4	686.0	681.4	725.4	588.5
2	Forecast Darlington Operating Costs as a % of 2015		104.1%	98.8%	98.1%	104.4%	84.7%

The majority of costs associated with the full-time operation of Darlington remain fixed as many of the functions that support the operation of all four units continue to be required during refurbishment to support the operation of a multi unit station even while units are on refurbishment outages. Examples of operating costs that remain even if one unit is in refurbishment include:

- Operating and maintaining safety systems and other common systems (i.e., Unit 0).
- Tritium removal facility that supports the remaining operating units, Pickering and other nuclear plants as well as other common facilities (e.g., water treatment plant).
- Fuel handling maintenance and operations to support fueling of the remaining operating units as well as fueling of the units undergoing refurbishment. Costs of defueling of the refurbishment units are included in DRP.

There are no savings during the 2017-2021 period associated with the changes to the earnings basis for pensions and changes to retirement eligibility for undiscounted pensions for unionized employees because, as noted at Ex. F4-3-1, p. 16, lines 12-14 and lines 20-21, these changes apply to future service accrued by employees after March 31, 2025.

e) Most major Ontario public sector pension plans currently utilize a Rule of 85 (with some of these requiring a minimum age of 55), with some also utilizing a Rule of 90.

f) OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information for periods beyond the IR Term that is not relevant to deciding any issue on the approved Issues List in this application and is not readily available.

g) The total projected costs associated with the “lump sum payments” made in the first two years of the respective collective agreements, and the Share Performance Plan for the remaining years of the respective collective agreements, attributed to the nuclear facilities are $92M over the 2017-2021 period ($26M in 2017, $24M in 2018, $15M in 2019, $14M in 2020, and $13M in 2021). These costs are reflected in Figure 3 at Ex. F4-3-1, p. 6.

OPG notes that, unlike employee contribution increases that apply to both existing and new employees, the Share Performance Plan applies only to employees contributing to the pension plan on April 1, 2015 (PWU) and January 1, 2016 (Society), and having less than 35 years of pensionable service as of those dates, as noted at Ex. F4-3-1, p. 17, lines 7-11. This means that while savings from higher employee contributions are expected to continue at similar levels beyond 2021, the cost of the Share Performance Plan will decline as the number of eligible employees declines.

h) [redacted]

dental benefits during employment, pensions, other post-retirement benefits, or long-term disability benefits from OPG. Please also see L-06.6-15 SEC-71.

Table 2: OPG Regular Employee Headcount – Business Plan

	2016	2017	2018	2019	2020	2021
Total OPG	[redacted]					
Change						
% Change						

Table 3 shows total OPG external hires for regular employees from 2011-2015. The lower hiring in 2012, 2013 and 2014 is due to Business Transformation activities. Increased hiring in 2015 and 2016 is as a result of replacing employees who have attrited from OPG and to meet the needs of the Darlington Refurbishment project.

Table 3: OPG External Hires - Regular Employees

	2011	2012	2013	2014	2015
Hires	207	77	83	177	291
Change		-130	6	94	114
% Change		-63%	8%	113%	64%

Table 4 shows total OPG actual attrition for regular employees from 2011-2015. As shown in this table, the attrition rate for 2011-2015 (total year-end attrition as a percentage of prior year-end headcount) is in the range of 5% to 7%.

Table 4: OPG Actual Attrition - Regular Employees

	2011	2012	2013	2014	2015
Attrition	542	613	646	765	687
Attrition Rate	5%	5%	6%	7%	7%

Table 5 shows total OPG forecast attrition for regular employees for 2016- 2021. The forecast attrition is based on December 31, 2015 assumptions, and may vary in future when actual attrition is incorporated and assumptions change. Other attrition refers to attrition excluding retirements.

Table 5: OPG Forecast Attrition - Regular Employees

	2016	2017	2018	2019	2020	2021
Retirement	[redacted]					
Other attrition						
Total OPG forecast attrition						