SEC Interrogatory #129

Ref: C2-1-1/p.4

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Please confirm that the accretion rate of 5.37% is based on 2012 cost of capital. Please provide full calculations for the accretion rate for each of 2013 through 2015.

Response

OPG confirms that the weighted average accretion rate of 5.37% is based on the December 31, 2012 balances of the nuclear asset retirement obligation. As these are also the opening balances for 2013, the rate of 5.37% represents the weighted average accretion rate for 2013.

Attached Table 1 provides the full calculation of the weighted average accretion rate as at December 31, 2012, December 31, 2013 and December 31, 2014 applicable to 2013, 2014 and 2015, respectively.

Table 1

Calculation of Weighted Average Accretion Rate for 20013-2015[1]

Line No.	Asset Retirement Obligation Tranche[2]	Year-end Balance ($M) (a)	Weighting (b)	Accretion Rate[3] (c)	Weighted Average Accretion Rate (d) = (b) x (c)
	2013 Budget - As of December 31, 2012[4]				
1	Tranche 1	11,584.4	76.4%	5.75%	4.40%
2	Tranche 2	1,726.5	11.4%	4.60%	0.52%
3	Tranche 3	398.6	2.6%	4.80%	0.13%
4	Tranche 4	994.0	6.6%	3.43%	0.22%
5	Tranche 5	451.1	3.0%	3.50%	0.10%
6	**Total/Weighted average as at year-end[5]**	15,154.5	100.0%		**5.37%**
	2014 Plan - As of December 31, 2013				
7	Tranche 1	12,058.4	76.2%	5.75%	4.38%
8	Tranche 2	1,777.4	11.2%	4.60%	0.52%
9	Tranche 3	411.1	2.6%	4.80%	0.12%
10	Tranche 4	1,011.8	6.4%	3.43%	0.22%
11	Tranche 5	571.7	3.6%	3.50%	0.13%
12	**Total/Weighted average as at year-end[5]**	15,830.4	100.0%		**5.37%**
13	**2015 Plan - As of December 31, 2014**				
14	Tranche 1	12,534.0	75.9%	5.75%	4.36%
15	Tranche 2	1,827.3	11.1%	4.60%	0.51%
16	Tranche 3	423.5	2.6%	4.80%	0.12%
17	Tranche 4	1,028.4	6.2%	3.43%	0.21%
18	Tranche 5	699.6	4.2%	3.50%	0.15%
19	**Total/Weighted average as at year-end[5]**	16,512.8	100.0%		**5.36%**

Notes:

1 Numbers may not calculate due to rounding

2 Tranches correspond to the following: Tranche 1 = ARO recorded prior to December 31, 2006; Tranche 2 = ARO recorded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan; Tranche 3 = ARO recorded on December 31, 2010 in relation to the decision related to the Darlington refurbishment project; Tranche 4 = ARO recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan; Tranche 5 = ARO recorded on December 31, 2012 arising from the approved 2012 ONFA Reference Plan.

3 As shown in EB-2012-0002, Ex. M1-1, Attachment 3, Table 1a, Note 1, col. (c)

4 As shown in EB-2012-0002, Ex. M1-1, Attachment 3, Table 1a, Note 1

5 Represents OPG's total nuclear ARO excluding consolidation adjustments

SEC Interrogatory #130

Ref: C2-1-1/Table 1a

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

With respect to this table:

(a) Please confirm that Line 1b is essentially the amount included in rates with respect to nuclear liabilities, before any tax impact, and Line 2b is the amount that the Applicant actually has to contribute to the Nuclear Segregated Funds.

(b) Please confirm that the Applicant proposes to collect $456.1 million ($214.6+213.2+14.8+13.5) from ratepayers in 2014 and 2015 for nuclear liabilities, but only contribute $342.9 million ($170.1+172.8) to the Nuclear Segregated Funds for the same period.

(c) Please advise how the Applicant accounts in its financial and regulatory accounts for the $113.2 million difference.

(d) Please explain how the accounting for these items differs in the case of the Bruce Facilities.

Response

a) OPG confirms that the referenced amounts are as described in the question, for the prescribed facilities' portion of nuclear liabilities and nuclear segregated funds.

b) Confirmed for the prescribed facilities' portion of nuclear liabilities. However, the two numbers are not comparable in any way. First, it is not appropriate to include the income tax impacts of $14.8M and $13.5M in the amount collected from ratepayers but not account for the amount of tax that OPG will have to pay on these amounts. Second, amounts collected in rates are not only in relation to amounts OPG is required to contribute to the nuclear segregated funds but also for internal expenditures on nuclear decommissioning and used fuel and low and intermediate level waste management, i.e., those that are not reimbursed by the nuclear segregated funds. The planned internal expenditures for the test period are $167.3M ($86.2M for 2014 and $81.1M for 2015), bringing the total amount OPG plans to spend in relation to nuclear liabilities during the test period to $510.2M.[1]

[1] Planned internal expenditure amounts are derived as the difference between total planned expenditures and those planned to be reimbursed from the nuclear segregated funds, i.e., line 7 less line 17 of Ex. C2-1-1, Table 2.

c) The difference of $113.2M does not represent a transaction or circumstance that is recognized for financial accounting purposes. Amounts included in the approved revenue requirement for recovery of nuclear liability costs are recognized as revenue to OPG, as part of the total approved payment amount OPG receives for nuclear generation. Amounts contributed to the nuclear segregated funds are recognized as a reduction in OPG's cash balance and an increase in the nuclear segregated fund assets. OPG anticipates continuing to follow the same financial accounting practice for regulatory accounting purposes

d) The response in part (c) applies both to prescribed and Bruce facilities.

SEC Interrogatory #131

Ref: H1-1-1/Table 7

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Please provide the full calculation of the rate base amount on line 1, including the amounts of additions, the month each addition became used and useful, and all related calculations.

Response

Chart 1 below presents the full calculation of the actual 2013 Net Plant Rate Base amount of $1,140.4M related to the Niagara Tunnel Project shown at Ex. L-9.1-17 SEC-132, Attachment 1, Table 7, line 1.

Chart 1

Numbers may not calculate due to rounding

Niagara Tunnel Project

(in millions$)	Pre-2013	2013 In-Service Additions		Total
	(a)	(b)	(c)	(d)
2013 In-service Additions	-	1,424.9	14.3	1,439.2
In-Service Dates		Mar-13	Dec-13	
Months In-service in 2013	12.0	9.5	1.0	
Gross Plant In-service (o/b)	19.2	-	-	19.2
Gross Plant In-service Additions	-	1,424.9	14.3	1,439.2
Gross Plant In-service (c/b)	19.2	1,424.9	14.3	1,458.4
Gross Plant Rate Base[1]	19.2	1,128.0	1.1917	1,148.4
Accumulated Depreciation (o/b)	1.5	-	-	1.5
Depreciation	0.3	12.7	0.0	13.0
Accumulated Depreciation (c/b)	1.8	12.7	0.0	14.5
Rate Base Accumulated Depreciation[2]	1.8	6.4	0.0	8.1
Total Actual Net Plant Rate Base Amount[3]	**17.4**	**1,121.7**	**1.2**	**1,140.4**

o/b= opening balance, c/b = closing balance

Notes:

1 In calculating the Gross Plant Rate Base amount, the 2013 in-service additions were assigned weighting of 9.5/12 and 1/12, respectively, as discussed in Ex. B1-1-1.

2 Represents the average of the opening and closing accumulated depreciation.

3 Calculated as the net of Gross Plant Rate Base and the Rate Base Accumulated Depreciation.

SEC Interrogatory #132

Ref: H1-2-1/p.1

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Please file the audited balances in all deferral and variance accounts.

Response

Attachment 1 provides the details of actual balances in all of OPG's deferral and variance accounts at December 31, 2013 and reproduces tables originally included in the pre-filed evidence, as updated for 2013 actual information.

As OPG does not propose to clear balances in all deferral and variance accounts in this application, the stand-alone audit of December 31, 2013 account balances by OPG's auditor, Ernst & Young LLP, was limited to the accounts proposed to be cleared. The auditors' report is included in Attachment 2.

A continuity schedule showing actual additions, amortization and interest for each deferral and variance account in 2013 is provided in Attachment 1, Table 1, which in col. (i) also presents the projected balances originally provided in Ex. H1-1-1 ,Table 1. Attachment 1, Tables 2 - 14 show the derivation of additions to the accounts in the same format as the corresponding tables accompanying Ex. H1-1-1.

LIST OF ATTACHMENTS

Attachment 1:	Updated Deferral and Variance Account Tables
Attachment 2:	Audited Schedule of Select Regulatory Balances as at December 31, 2013

Numbers may not add due to rounding.

Table 1
(Updated version of Ex. H1-1-1 Table 1)
Deferral and Variance Accounts
Continuity of Account Balances - 2012 to 2013 ($M)

Line No.	Account	Audited Year End Balance 2012[1]	EB-2012-0002 Negotiated Reductions[2]	(a)+(b) EB-2012-0002 Year End Balance 2012[3]	Actual 2013 Transactions	Actual 2013 Amortization[4]	Actual 2013 Interest[5]	Actual 2013 Transfers	(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2013	Projected Year End Balance 2013[7]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Previously Regulated Hydroelectric:									
1	**Hydroelectric Water Conditions Variance**	17.1	0.0	17.1	15.2	(10.3)	0.4	0.0	22.4	42.7
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	0.0	34.0	1.8	(20.4)	0.4	0.0	15.8	35.3
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	(2.4)	(2.5)	0.0	(0.0)	0.0	(5.0)	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	4.1	14.9	0.0	0.1	0.0	19.2	8.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	0.0	(2.5)	(0.1)	1.5	(0.0)	0.0	(1.1)	(1.1)
6	**Tax Loss Variance - Hydroelectric**	48.2	0.0	48.2	0.0	(28.9)	0.5	0.0	19.7	19.8
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	1.1	111.1	0.0	0.5	0.0	112.7	114.4
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	0.0	2.5	0.0	(1.5)	0.0	0.0	1.0	1.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	0.0	12.6	0.0	(1.3)	0.0	0.0	11.3	11.3
10	**Pension and OPEB Cost Variance - Hydroelectric - 2013 Additions**	N/A	N/A	N/A	18.6	0.0	0.0	0.0	18.6	21.5
11	**Impact for USGAAP Deferral - Hydroelectric**	2.8	0.0	2.8	0.0	(1.7)	0.0	0.0	1.2	1.2
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	0.0	(3.9)	2.9	2.3	(0.0)	0.0	1.3	4.3
13	**Total**	113.8	0.0	113.8	162.0	(60.3)	1.8	0.0	217.3	256.0
	Nuclear:									
14	**Nuclear Liability Deferral**	208.0	(1.8)	206.2	122.7	(74.9)	0.0	0.0	254.0	254.0
15	**Nuclear Development Variance**	30.2	0.0	30.2	25.6	0.0	0.7	0.0	56.5	69.4
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	1.2	(1.0)	0.0	0.0	1.9	1.8
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	0.0	1.3	4.3	0.0	0.0	0.0	5.7	3.7
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	0.0	11.8	4.0	(7.1)	0.1	0.0	8.9	25.4
19	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	0.0	230.3	24.6	(40.5)	(0.0)	0.0	214.4	189.8
20	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account**	80.2	(5.5)	74.8	85.8	(22.4)	0.0	0.0	138.1	139.3
21	**Income and Other Taxes Variance - Nuclear**	(32.5)	0.0	(32.5)	(4.5)	19.5	(0.3)	0.0	(17.9)	(14.7)
22	**Tax Loss Variance - Nuclear**	253.3	0.0	253.3	0.0	(152.0)	2.5	0.0	103.8	104.0
23	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	0.0	51.5	0.0	(31.4)	0.5	0.0	20.7	20.5
24	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	0.0	257.6	0.0	(25.8)	0.0	0.0	231.8	231.8
25	**Pension and OPEB Cost Variance - Nuclear - 2013 Additions**	N/A	N/A	N/A	383.7	0.0	0.0	0.0	383.7	375.9
26	**Impact for USGAAP Deferral - Nuclear**	60.3	0.0	60.3	0.0	(36.2)	0.6	0.0	24.7	24.8
27	**Pickering Life Extension Depreciation Variance[6]**	N/A	N/A	N/A	(46.8)	56.3	0.0	0.0	9.5	9.5
28	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	0.0	6.9	39.5	(4.2)	0.3	0.0	42.6	22.1
29	**Total**	1,160.6	(7.3)	1,153.3	640.2	(319.5)	4.4	0.0	1,478.4	1,457.1
30	**Grand Total**	1,274.4	(7.3)	1,267.1	802.2	(379.8)	6.2	0.0	1,695.7	1,713.1

Notes:
1 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (a) for regulated hydroelectric and Table 2 col. (a) for nuclear.
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (b) for regulated hydroelectric and Table 2 col. (b) for nuclear.
3 All balances from EB-2012-0002, Ex. M1-1 Attachment 1, Tables 16A and 17A, col. (c). With the exception of balances at lines 3, 4, 7, 10, 15, 17, 25 and 27, all balances were approved by the OEB in EB-2012-0002 (Payment Amounts Order, App. B, Table B-1, col. (a)).
4 From EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (c).
5 Effective January 1, 2013, per EB-2012-0002 Payments Amount Order, no interest is recorded in the Nuclear Liability Deferral Account, and, up to December 31, 2014, no interest is recorded in the Bruce Lease Net Revenues Variance Account and the Future Recovery component of the Pension and OPEB Cost Variance Account on outstanding balances. Up to December 31, 2014, interest is also not being recorded on the 2013 additions to the Pension and OPEB Cost Variance Account. Line 19 includes an interest credit related to the inadvertent overstatement of the amount recoverable in 2013 and 2014 for the Derivative Sub-Account, as noted in Ex. H1-1-1, section 4.13 and OPG's letter to the OEB dated September 26, 2013 referenced therein.
6 Per the EB-2012-0002 Payment Amounts Order, the account reflects a credit of $3.9M per month to ratepayers for the benefit of lower non-asset retirement costs depreciation expense and associated income tax impacts resulting from the revision of the Pickering generation stations' service lives, as discussed in Ex. H1-1-1 section 4.14. No interest is recorded in this account.
7 From Ex. H1-1-1 Table 1, col. (h)

Numbers may not add due to rounding.

Table 2
(Updated version of Ex. H1-1-1 Table 2)
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - Actual 2013

Line No.	Particulars	Actual 2013
		(a)
1	**Forecast Production - EB-2012-0002[1] (GWh)**	19,832
2	**Actual Calculated Production (GWh)**	19,167
3	**Difference (GWh)** (line 1 - line 2)	664
4	**Revenue Impact at $35.78/MWh ($M)**	23.8
5	**GRC/Water Rental Costs ($M)**	(8.5)
6	**Addition to Variance Account ($M)** (line 4 + line 5)	15.2

Notes:

1 2013 forecast production has been determined using the average monthly forecasts for 2011 and 2012 underpinning the reference amounts from EB-2010-0008 per EB-2012-0002 Payment Amounts Order, App. B, page 3.

Numbers may not add due to rounding.

Table 3
(Updated version of Ex. H1-1-1 Table 3)
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - Actual 2013 ($M)

Line No.	Particulars	Actual 2013 Hydroelectric	Actual 2013 Nuclear
		(a)	(b)
1	**Forecast Revenue - EB-2012-0002**[1]	38.9	3.0
2	**Actual Revenue**[2]	37.1	1.7
3	**Addition to Variance Account** (line 1 - line 2)	1.8	1.2

Notes:

1 For Hydroelectric, $3.24M x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 4.
For Nuclear, $0.25M x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 10.

2 Hydroelectric actual 2013 ancillary revenue is from Ex. L-1.0-1 Staff-002, Att. 1, Table 34, col. (d), line 1.
Nuclear actual 2013 ancillary revenue is from Ex. L-1.0-1 Staff-002, Att. 1, Table 35, col. (d), line 8.

Numbers may not add due to rounding.

Table 4
(Updated version of Ex. H1-1-1 Table 4)
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2011 to 2013 ($M)

Line No.	Particulars	Actual Mar-Dec 2011	Actual 2012	Actual 2013
		(a)	(b)	(c)
1	**Actual Hydroelectric Incentive Mechanism Net Revenue**[1]	12.9	15.8	18.1
2	**Threshold per EB-2010-0008 / EB-2012-0002**[2]	10.0	14.0	13.0
3	**Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold** (line 1 - line 2; nil if line 1 < line 2)	2.9	1.8	5.1
4	**Percentage**	50%	50%	50%
5	**Addition to Variance Account**[3] (line 3 x line 4)	(1.4)	(0.9)	(2.5)

Notes:
1 2011 and 2012 net revenue from Ex. E1-2-1 Section 5.0. 2013 net revenue as noted in L-05.4-17 SEC-069.
2 2011 and 2012 thresholds from EB-2010-0008 Payment Amounts Order, App. F, Page. 9. 2013 threshold from EB-2012-0002 Payment Amounts Order, App. B, page 8.
3 2011 and 2012 additions as presented at line 3 of EB-2012-0002, Ex. H1-1-2 Tables 1b and 1c, respectively.

Table 5
(Updated version of Ex. H1-1-1 Table 5)
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2011 to 2013 ($M)

Line No.	Particulars	Actual Mar-Dec 2011	Actual 2012	Actual 2013
		(a)	(b)	(c)
1	**Actual Foregone Production Due to SBG Conditions[1] (GWh)**	76.5	116.9	698.7
2	**Revenue at $35.78/MWh ($M)**	2.7	4.2	25.0
3	**GRC/Water Rental Costs ($M)**	(1.1)	(1.7)	(10.1)
4	**Addition to Variance Account ($M)** (line 2 + line 3)	1.6	2.5	14.9
5	**Financial Reporting Adjustment[2]**	(1.1)	1.1	0.0
6	**Reported Addition to Variance Account[3] ($M)** (line 4 + line 5)	0.5	3.6	14.9

Notes:
1 2011 and 2012 foregone production from Ex. E1-2-1 Section 3.2.
2 Represents offsetting interperiod financial statement reconciliation adjustments which do not impact the total transactions in the account over the 2011-2012 period.
3 2011 and 2012 additions as presented at line 4 of EB-2012-0002, Ex. H1-1-2 Tables 1b and 1c, respectively

Table 6
(Updated version of Ex. H1-1-1 Table 6)
Income and Other Taxes Variance Account
Summary of Account Transactions - Actual 2013[1] ($M)

Line No.	Particulars	Note	Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
	Entry (i) Increase of Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits (ITCs) Recognition Percentage from 50% to 75% for 2013				
1	**Actual SR&ED ITCs, net of Tax on ITCs of Prior Periods, at 50%**	2	(0.1)	(6.5)	(6.6)
2	**Actual SR&ED ITCs, net of Tax on ITCs of Prior Periods, at 75%** (line 1 x 3/2)		(0.1)	(9.8)	(9.9)
3	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase for 2013** (line 2 - line 1)		(0.0)	(3.3)	(3.3)
	Entry (ii) Reduction in Contractor Payments Qualifying for SR&ED ITCs from 100% to 80%				
4	**Annual Qualifying Contractor Payments Reflected in SR&ED ITCs**		0.6	57.4	58.0
5	**20% Portion Not Eligible for SR&ED ITCs** (line 4 x 20%)		0.1	11.5	11.6
6	**Investment Tax Credit Rate**	3	20%	20%	20%
7	**Reduction in SR&ED ITCs** (line 5 x line 6)		0.0	2.3	2.3
8	**Addition to Variance Account - Reduction in Contractor Payments Qualifying for SR&ED ITCs** (line 7 x 75%)		0.0	1.7	1.7
	Entry (iii) Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment				
9	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		0.0	(4.5)	(4.5)
10	**Additional Capital Cost Allowance**		0.0	(3.7)	(3.7)
11	**Impact on Taxable Income** (line 9 - line 10)		0.0	(0.8)	(0.8)
12	**Income Tax Rate**	4	25.00%	25.00%	25.00%
13	**Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (line 11 x line 12)		0.0	(0.2)	(0.2)
	Entry (iv) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% for April 1, 2008 to December 31, 2008				
14	**Actual SR&ED ITCs, net of Tax on ITCs of Prior Periods, at 75%**	5	(0.1)	(8.5)	(8.6)
15	**Actual SR&ED ITCs, net of Tax on ITCs of Prior Periods, at 100%** (line 14 x 4/3)		(0.1)	(11.3)	(11.4)
16	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase for 2008** (line 2 - line 1)		(0.0)	(2.8)	(2.9)
17	**Total Addition to Variance Account** (line 3 + line 8 + line 13 + line 16)		(0.1)	(4.5)	(4.6)

Notes:
1 Entries (i), (ii) and (iii) are discussed in Ex. H1-1-1 Section 4.5 and Ex. F4-2-1 Sections 3.3.3 and 3.5. Entry (iv) was recorded following the resolution during 2013 of the 2008 taxation year audit. An additional entry of less than $0.1M is reflected in the December 31, 2013 account balance relating to SR&ED qualifying capital expenditures.
2 Forecasts for 2013 have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008 using the methodology from the EB-2012-0002 Payment Amounts Order, as follows:

Table to Note 2 - Forecast SR&ED ITCs, Net of Tax on ITCs of Prior Periods ($M)

Line No.			2011	2012	Total
			(a)	(b)	(c)
1a	Full Year SR&ED ITCs - Regulated Hydroelectric (from EB-2010-0008, Ex. F4-4-1 Table 2, line 5)		(0.1)	(0.1)	(0.2)
2a	Full Year SR&ED ITCs - Nuclear (from EB-2010-0008, Ex. F4-4-1 Table 3, line 6)		(8.7)	(8.7)	(17.4)
3a	Less: Full Year Taxable ITCs of Prior Periods x tax rate (26.50% for 2011 and 25.00% for 2012) - Regulated Hydroelectric[#]		0.0	0.0	0.1
4a	Less: Full Year Taxable ITCs of Prior Periods x tax rate (26.50% for 2011 and 25.00% for 2012) - Nuclear[#]		2.3	2.2	4.4
5a	Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods, from EB-2010-0008 - Regulated Hydroelectric (lines 1a + 3a)		(0.1)	(0.1)	(0.1)
6a	Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods, from EB-2010-0008 - Nuclear (lines 2a +4a)		(6.4)	(6.6)	(13.0)
7a	Annualized Forecast Amount ((line 5a, col. (c) / 24 months) x 12 months) - Regulated Hydroelectric				(0.1)
8a	Annualized Forecast Amount ((line 6a, col. (c) / 24 months) x 12 months) - Nuclear				(6.5)

\# Total full year taxable ITCs of prior periods for regulated operations are shown in EB-2010-0008 Payment Amounts Order, App. A, Tables 6 and 7, line 11.

3 As discussed in Ex. F4-2-1, section 3.5.
4 2013 tax rate from Ex. F4-2-1 Table 5, line 29.
5 Represents SR&ED ITCs, net of tax on ITCs of prior periods, for the period from April 1, 2008 to December 31, 2008 previously credited to ratepayers at 75% through the December 31, 2010 and December 31, 2012 approved balances of the Income and Other Taxes Variance Account . The amount in col. (c) can be calculated as: 3/2 x (EB-2010-0008 Ex. H1-1-1, Table 13, col. (a), line 2 + line 4).

Table 7
(Updated version of Ex. H1-1-1 Table 7)
Capacity Refurbishment Variance Account - Hydroelectric
Summary of Account Transactions - 2011 to 2013 ($M)

Line No.	Particulars	Note	Actual 2011	Actual 2012	Actual 2013
			(a)	(b)	(c)
	Niagara Tunnel Project - Capital Variance Account Addition:				
1	**Total Actual Net Plant Rate Base Amount**	1			1,140.4
2	**Less: Net Plant Amount Previously Reflected in Rate Base**	2			17.4
3	**Net Plant Amount Not Reflected in Rate Base** (line 1 - line 2)				1,123.0
4	**Weighted Average Cost of Capital - EB-2010-0008**	3			7.40%
5	**Niagara Tunnel Project - Cost of Capital Addition** (line 3 x line 4)		0.0	0.0	83.1
6	**Niagara Tunnel Project - Depreciation Addition**		0.0	0.0	12.7
	Income Tax Impact:				
7	**Difference Between Forecast and Actual CCA Deduction**	4	(7.5)	5.4	(4.5)
8	**Increase in Regulatory Taxable Income**	5	(7.5)	5.4	58.7
9	**Niagara Tunnel Project - Income Tax Impact** (line 8 x tax rate / (1 - tax rate))	6	(2.3)	1.8	19.6
10	**Niagara Tunnel Project - Capital Addition** (line 5 + line 6 + line 9)		(2.3)	1.8	115.4
11	**Niagara Tunnel Project - Non-Capital Addition**	7	1.4	0.2	0.0
12	**Niagara Tunnel Project - Total Addition** (line 10 + line 11)		(0.9)	2.0	115.4
	Variance Account Additions for:				
13	**Sir Adam Beck I GS Unit G7 Frequency Conversion**	8	(0.1)	0.2	0.4
14	**Sir Adam Beck I GS Unit G3 Upgrade**	8	(1.0)	(1.4)	0.6
15	**Sir Adam Beck I GS Unit G9 Upgrade**	8	(2.7)	(0.2)	0.0
16	**Total Addition to Variance Account - Hydroelectric** (lines 12 through 15)		(4.8)	0.6	116.5
17	**Financial Reporting Adjustment**	9	4.0	1.3	(5.4)
18	**Reported Addition to Variance Account - Hydroelectric** (line 16 + line 17)	10	(0.7)	1.9	111.1

Notes:
1 As shown in Ex. L-9.1-17 SEC-131, Chart 1, col. (d).
2 As shown in Ex. L-9.1-17 SEC-131, Chart 1, col. (a).
3 From EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6.
4 The differences between forecast and actual CCA related to the Niagara Tunnel Project are shown below at line 3a for the period starting on April 1, 2008.
The income tax impact of these differences is shown at line 5a and is included in the total income tax impact amounts at line 9.
Amount in col. (a) is for the period from April 1, 2008 to December 31, 2011 as shown in col. (f), line 5a.

Table to Note 3 - Difference Between Forecast and Actual CCA Deduction

Line No.	Item	Actual Apr - Dec 2008	Actual 2009	Actual 2010	Actual Jan - Feb 2011	Actual Mar - Dec 2011	Total Apr 2008 - Dec 2011	Actual 2012	Actual 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1a	Forecast CCA Deduction - EB-2007-0905 / EB-2010-0008 #	19.0	26.9	26.3	4.4	26.4	103.0	40.5	36.5
2a	Actual CCA Deduction	19.1	23.5	23.7	7.4	37.0	110.5	35.2	41.0
3a	Difference (line 1a - line 2a)	(0.0)	3.5	2.6	(3.0)	(10.6)	(7.5)	5.4	(4.5)
4a	Income Tax Rate +	31.50%	31.00%	29.00%	26.50%	26.50%		25.00%	25.00%
5a	Income Tax Impact (line 3a x line 4a / (1 - line 4a)	(0.0)	1.6	1.1	(1.1)	(3.8)	(2.3)	1.8	(1.5)

\# Cols. (a) and (b) amounts are those underpinning the OEB-approved forecast income tax expense for 2008 and 2009. Col. (c) is (col. (a) + col. (b)) / 21 months x 12 months.
Col. (d) is (col. (a) + col. (b)) / 12 months x 2 months. Cols. (e) and (g) amounts are those underpinning the OEB-approved forecast income tax expense for 2011 and 2012.
Col. (h) is (col. (e) + col. (f)) / 22 months x 12 months.

\+ 2010, 2011 and 2012 tax rates from Ex. F4-2-1 Table 4, line 33. 2013 tax rate from Ex. F4-2-1 Table 5, line 29.

5 As shown in Ex. L-9.2-1 Staff-185.
6 Income tax impact in col. (a) is as shown at col. (f), line 5a. Income tax impact for col. (b) is as shown at col. (g), line 5a.
7 As discussed in Ex. D1-2-1, section 1.2, non-capital costs incurred in 2011 - 2012 represent removal costs. No such costs were forecast in the EB-2010-0008 payment amounts.
8 Amount in col. (a) represents the variance for the period April 1, 2008 to December 31, 2011.
9 Represents offsetting interperiod financial statement reconciliation adjustments which do not impact total transactions in the account over the 2011-2013 period.
10 2011 and 2012 additions as presented at line 7 of EB-2012-0002, Ex. H1-1-2 Tables 1a / 1b and 1c, respectively.

Numbers may not add due to rounding.

Table 8
(Updated version of Ex. H1-1-1 Table 8)
Pension and OPEB Cost Variance Account
Summary of Account Transactions - Actual 2013[1] ($M)

Line No.	Particulars	Note	Actual 2013 Hydroelectric	Actual 2013 Nuclear	Actual 2013 Total
			(a)	(b)	(c)
1	**Forecast Pension Costs - EB-2012-0002**	2	7.0	138.4	145.4
2	**Forecast OPEB Costs - EB-2012-0002**	2	8.2	163.0	171.2
3	**Total Forecast Pension and OPEB Costs** (line 1 + line 2)	2	15.1	301.4	316.5
4	**Actual Pension Costs**	3	18.0	365.3	383.3
5	**Actual OPEB Costs**	3	11.5	233.7	245.2
6	**Total Actual Pension and OPEB Costs** (line 4 + line 5)		29.5	599.0	628.5
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		11.0	226.9	237.9
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		3.4	70.7	74.0
9	**Addition to Variance Account - Income Tax Impact**	4	4.3	86.1	90.4
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		18.6	383.7	402.3

Notes:

1 All cost amounts are presented on a CGAAP basis, as per the EB-2012-0002 Payment Amounts Order, App. B.

2 2013 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and are the same as those used to derive the OEB-approved 2012 additions to the variance account (shown in EB-2012-0002, Ex. H1-1-2 Table 5). Total forecast costs for the regulated operations as per EB-2012-0002 Payment Amounts Order, App. B, p. 6, determined as $26.38M/month x 12.

3 Amounts represent the regulated portion of OPG's 2013 total actual pension and OPEB costs on a CGAAP basis.

4 From Ex. L-9-1 Schedule 17 SEC-132, Attachment 1, Table 8a, line 8.

Numbers may not add due to rounding.

Table 8a
(Updated version of Ex. H1-1-1 Table 8a)
Pension and OPEB Cost Variance Account
Calculation of Income Tax Impact - Actual 2013 ($M)

Line No.	Particulars	Note	Actual 2013 Hydroelectric	Actual 2013 Nuclear	Actual 2013 Total
			(a)	(b)	(c)
1	**Forecast Regulatory Income Tax Impact**	1	0.5	10.3	10.8
	Actual Additions to / Deductions from Regulatory Earnings Before Tax				
2	**Pension Costs** (Ex. L-9.1-17 SEC-132, Table 8, line 4)		18.0	365.3	383.3
3	**OPEB Costs** (Ex. L-9.1-17 SEC-132, Table 8, line 5)		11.5	233.7	245.2
4	**Less: Pension Plan Contributions**	2	11.4	231.6	242.9
5	**Less: OPEB Payments**	2	3.8	78.1	81.9
6	**Net Additions to Regulatory Earnings Before Tax**		14.2	289.4	303.6
7	**Actual Regulatory Income Tax Impact** (line 6 x 25% / (1 - 25%))		4.7	96.5	101.2
8	**Addition to Variance Account - Regulatory Income Tax Impact** (line 7 - line 1)		4.3	86.1	90.4

Notes:
1. 2013 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and are the same amounts used to derive the OEB-approved 2012 additions (as shown in EB-2012-0002, Ex. H1-1-2 Table 5a).
2. Represents the regulated portion of OPG's 2013 total actual pension and OPEB cash amounts.
   Amounts at line 4 are as shown in Ex. L-6.8-1 Staff-114.

Numbers may not add due to rounding.

Table 9
(Updated version of Ex. H1-1-1 Table 9)
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - Actual 2013

Line No.	Particulars	Note	Actual 2013
			(a)
1	**Hydroelectric Rider 2013-A ($/MWh)**	1	3.04
2	**Hydroelectric Rider 2013-B ($/MWh)**	2	0.58
3	**Full Year Hydroelectric Forecast Production Used to Set Rider 2013-A - EB-2012-0002 (TWh)**	3	19.9
4	**Hydroelectric Production Forecast Used to Set Rider 2013-B (TWh)**	4	16.7
5	**Actual Hydroelectric Mar-Dec 2013 Production (TWh)**		15.9
6	**Actual Mar-Dec 2013 Production Variance (TWh)** (line 4 - line 5)		0.8
7	**Addition to Variance Account ($M)** (line 6 x (line 1 + line 2))		2.9

Notes:
1 From EB-2012-0002 Payment Amounts Order, App. A, Table 1, col. (g), line 13.
2 Interim period shortfall rider from EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (a), line 7.
3 From EB-2012-0002 Payment Amounts Order, App. A, Table 1, col. (g), line 12.
4 Calculated from the EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (a): line 6 minus line 5.

Table 10
(Updated version of Ex. H1-1-1 Table 10)
Nuclear Liability Deferral Account
Summary of Account Transactions - Actual 2013 ($M)

Line No.	Particulars	Note	Actual 2013
			(a)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:		
1	**Depreciation Expense**	1	51.7
	Return on Rate Base		
2	**Average Asset Retirement Costs** (line 5a + (line 5a - line 13a))/2		38.3
3	**Weighted Average Accretion Rate**	2	5.37%
4	**Return on Rate Base** (line 2 x line 3)		2.1
	Variable Expenses	3	
5	**Used Fuel Storage and Disposal Variable Expenses**		26.1
6	**Low & Intermediate Level Waste Management Variable Expenses**		1.0
7	**Total Variable Expenses** (line 5 + line 6)		27.1
	Income Tax Impact		
8	**Forecast Contributions to Nuclear Segregated Funds - EB-2010-0008**	4	142.7
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan**	5	98.1
10	**Decrease in Contributions to Nuclear Segregated Funds** (line 8 - line 9)		44.6
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)		125.5
12	**Income Tax Rate**		25.00%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))		41.8
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)		122.7

Notes:
1 The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 1 - Depreciation Expense ($M)

Line No.		Pickering A	Pickering B	Darlington	Total
		(a)	(b)	(c)	(d)
	Incremental ARC - Depreciation Impact of Adjustments at December 31, 2011 and 2012:				
1a	Asset Retirement Cost ("ARC") Adjustment at December 31, 2011 #	368.4	175.9	(105.1)	439.2
2a	Remaining Useful Life as at December 31, 2011(months) +	120.0	33.0	480.0	
3a	2012 Annual Depreciation (line 1a / line 2a x 12 for cols. (a) through (c))	36.8	64.0	(2.6)	98.2
4a	ARC Adjustment at December 31, 2012 ##	(178.5)	133.3	(231.7)	(276.9)
5a	Net ARC Adjustment Balance at December 31, 2012 (line 1a - line 3a + line 4a)	153.1	245.2	(334.2)	64.1
6a	Remaining Useful Life as at December 31, 2012 (months) ++	96.0	88.0	468.0	
7a	2013 Annual Depreciation Impact (line 5a / line 6a x 12 for cols. (a) through (c))	19.1	33.4	(8.6)	44.0
	Base ARC (Excluding Incremental ARC Above) - Depreciation Impact of Pickering Service Life Changes:				
8a	ARC at December 31, 2011 Excluding December 31, 2011 Adjustment *	17.3	(27.0)	1,485.0	1,475.4
9a	2012 Annual Depreciation (line 8a / line 2a x 12 for cols. (a) through (c))	1.7	(9.8)	37.1	29.0
10a	ARC at December 31, 2012 Excluding Dec. 31, 2011 and 2012 Adjustments (line 8a - line 9a)	15.6	(17.2)	1,447.9	1,446.3
11a	2013 Annual Depreciation (line 10a / line 6a x 12 for cols. (a) through (c))	1.9	(2.3)	37.1	36.7
12a	2013 Annual Depreciation Impact (line 11a - line 9a)	0.2	7.5	0.0	7.7
13a	Total 2013 Depreciation Expense Impact (line 7a + line 12a)	19.4	40.9	(8.6)	51.7

\# From Ex. C2-1-1 Table 4, line 7 and EB-2012-0002 Ex. H1-1-2, Table 9, note 2, line 1a.
\+ Represents remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2011, as per EB-2012-0002, Ex. H1-1-2, Table 9, note 2+.
\## From Ex. C2-1-1 Table 4, line 14.
\++ Represents-remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2012, as per Ex. F4-1-1, page 3.
* Amount in col. (d) from Ex. C2-1-1 Table 2, col. (b), line 28.

2 Return on rate base is calculated using the weighted average accretion rate of 5.37% per EB-2012-0002 Payment Amounts Order, App. B, pg. 9.
3 Calculated as: (A) the product of (i) 2013 unit cost rates for each of the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan, and (ii) average number of forecast fuel bundles and L&ILW volumes reflected in the EB-2010-0008 payment amounts, and (B) the average of 2011 and 2012 forecast variable expenses reflected in the EB-2010-0008 payment amounts.
4 Calculated as the average of 2011 and 2012 contributions from EB-2010-0008 Payment Amounts Order, App. A: Table 6, line 16, col. (c) for 2011 and Table 7, line 16, col. (c) for 2012.
5 As shown in Ex. L-1.0-1 Staff-002, Att. 1, Table 7, col. (a), line 16.

Numbers may not add due to rounding.

Table 11
(Updated version of Ex. H1-1-1 Table 11)
Nuclear Development Variance Account
Summary of Account Transactions - 2011 to 2013[1] ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Actual 2012	Actual 2013
		(a)	(b)	(c)	(d)	(e)
1	**Forecast Costs - EB-2009-0174 / EB-2010-0008 / EB-2012-0002** [2]	10.7	0.0	10.7	0.0	0.0
2	**Actual Costs**	2.8	14.5	17.3	25.2	25.6
3	**Addition to Variance Account** (line 2 - line 1)	(7.9)	14.5	6.6	25.2	25.6

Notes:
1 Darlington New Nuclear costs are discussed in Ex. F2-8-1.
2 January and February 2011 forecast is derived in accordance with the EB-2009-0174 Decision and Order.
March to December 2011 forecast and 2012 forecast are nil as no amounts were reflected in the payment amounts approved in EB-2010-0008.
Similarly, the 2013 forecast is nil as per EB-2012-0002 Payment Amounts Order, App. B, pg. 9.

Table 12
(Updated version of Ex. H1-1-1 Table 12)
Capacity Refurbishment Variance Account - Nuclear
Summary of Account Transactions - Actual 2013 ($M)

Line No.	Particulars	Note	Actual 2013
			(a)
	Forecast Non-Capital Costs - EB-2012-0002:	1	
1	**Darlington Refurbishment**		5.2
2	**Fuel Channel Life Cycle Management Project**		5.9
3	**Pickering Continued Operations**		42.0
4	**Total** (lines 1 through 3)		53.1
	Actual Non-Capital Costs:		
5	**Darlington Refurbishment**	2	6.3
6	**Fuel Channel Life Cycle Management Project**	3	9.2
7	**Pickering Continued Operations**		41.5
8	**Total** (lines 5 through 7)		57.0
	Non-Capital Addition to Variance Account:		
9	**Darlington Refurbishment - Non-Capital Costs** (line 5 - line 1)		1.1
10	**Fuel Channel Life Cycle Management Project - Non-Capital Costs** (line 6 - line 2)		3.3
11	**Pickering Continued Operations - Non-Capital Costs** (line 7 - line 3)		(0.5)
12	**Total Non-Capital Addition to Variance Account - Nuclear**		4.0
13	**Darlington Refurbishment - Capital Addition**	4	4.3
14	**Total Reported Addition to Variance Account - Nuclear** (line 12 + line 13)		8.3

Notes:

1 Forecasts have been determined based on amounts reflected in the EB-2010-0008 payment amounts and are the same as those reflected in the EB-2012-0002 approved December 31, 2012 balance of the account (see EB-2012-0002, Ex. H1-1-2, Table 12). Total forecast of $53.1M is as per the EB-2012-0002 Payment Amounts Order, App. B, p. 10, determined as $4.42/month x 12 months.

2 As shown in Ex. L1.0-1 Staff-002, Att. 1, Table 23, col. (d), line 3.

3 As shown in Ex. L1.0-1 Staff-002, Att.1, Table 21, col. (d), line 11.

4 From Ex. L9.1-17 SEC-132, Attachment 1, Table 12a, col. (c), line 13.

Table 12a
(Updated version of Ex. H1-1-1 Table 12a)
Capacity Refurbishment Variance Account - Nuclear - Capital Portion
Summary of Account Transactions - 2011 to 2013 ($M)

Line No.	Particulars	Notes	Actual 2011	Actual 2012	Actual 2013
			(a)	(b)	(c)
1	**Net Plant Amount Not Reflected in Rate Base**	1		2.5	60.2
2	**Weighted Average Cost of Capital - EB-2010-0008**	2		7.40%	7.40%
3	**Cost of Capital Addition** (line 3 x line 4)		0.0	0.2	4.5
4	**Depreciation Addition**	1	0.0	0.0	2.3
	Income Tax Impact:				
5	**Forecast CCA Deduction - EB-2007-0905 / EB-2010-0008**	3	0.0	7.9	3.9
6	**Actual CCA Deduction**		1.0	4.4	15.2
7	**Difference** (line 5 - line 6)		(1.0)	3.5	(11.3)
8	**Net Increase in Regulatory Taxable Income**	4	(1.0)	3.6	(6.3)
9	**Income Tax Rate**	5	26.50%	25.00%	25.00%
10	**Income Tax Impact** (line 8 x line 9 / (1 - line 9))		(0.4)	1.2	(2.1)
11	**Total Capital Addition to Variance Account - Nuclear** (line 3 + line 4 + line 10)		(0.4)	1.4	4.6
12	**Financial Reporting Adjustment**	6	0.4	(0.1)	(0.3)
13	**Reported Capital Addition to Variance Account - Nuclear** (line 11 + line 12)	7	0.0	1.3	4.3

Notes:

1 Net Plant Rate Base amounts are computed as follows:

Table to Note 1 - Net Plant Rate Base Amounts ($M)

Line No.		Opening Balance	In-Service Additions/ Depreciation	(a) + (b) Closing Balance	Rate Base Amount #
		(a)	(b)	(c)	(d)
	Actual 2012:				
1a	Gross Plant +	0.0	5.0	5.0	2.5
2a	Accumulated Depreciation	0.0	0.0	0.0	0.0
3a	Net Plant (line 1a - line 2a)	0.0	5.0	5.0	2.5
	Actual 2013:				
4a	Gross Plant ++	5.0	99.2	104.2	61.3
5a	Accumulated Depreciation	0.0	2.3	2.3	1.1
6a	Net Plant (line 4a - line 5a)	5.0	96.9	101.9	60.2

Calculated as (col. (a) + col. (c)) / 2 for lines 1a, 2a and 5a. The 2013 Gross Plant Rate Base Amount in line 4a reflects a seven-month weighting assigned to the $80.7M addition at the beginning of June 2013 related to the Darlington Energy Complex.

\+ In-service addition in 2012 relates to the Water and Sewer project.

++ In-service additions in 2013 relate to the Water and Sewer project ($15.8M) and the Darlington Energy Complex ($80.7M), as noted in Ex. L-4.7-2 AMPCO-20 (g) and (f), respectively; and the Electrical Power Distribution System project ($2.7M). The total in-service additions of $99.2M are as shown in Ex. L-2.1-13 LPMA-001. These projects are discussed in Ex. D2-2-1, section 7.2.

2 From EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6.

3 2011 and 2012 amounts are as noted in EB-2010-0008 Stakeholder Information Session 2 - Notes, para. 6.3.
Col. (c) is (col. (a) + col. (b)) / 24 months x 12 months. (No forecast amounts were reflected in the OEB-approved income tax expense for 2008 and 2009.)

4 As shown in Ex. L-9.2-1 Staff-186.

5 2011 and 2012 tax rates from Ex. F4-2-1 Table 4, line 33. 2013 tax rate from Ex. F4-2-1 Table 5, line 29.

6 Represents offsetting interperiod financial statement reconciliation adjustments which do not impact total transactions in the account over the 2011-2013 period.

7 2012 additions as presented in note 5 to EB-2012-0002, Ex. H1-1-2, Table 17.

Table 13
(Updated version of Ex. H1-1-1 Table 13)
Bruce Lease Net Revenues Variance Account[1]
Summary of Account Transactions - Actual 2013

Line No.	Particulars	Note	Actual 2013
			(a)
1	**Actual Total Bruce Lease Net Revenues ($M)**	2	8.1
2	**Forecast Bruce Lease Net Revenues - EB-2010-0008 ($M)**	3	135.5
3	**Nuclear Forecast Production - EB-2010-0008 (TWh)**	4	51.0
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)		2.66
5	**Actual Nuclear Production (TWh)**	5	44.7
6	**Amount Credited to Customers ($M)** (line 4 x line 5)		118.6
7	**Total Addition to Variance Account ($M)** (line 6 - line 1)		110.5
8	**Less: Addition to Derivative Sub-Account ($M)**	6	24.6
9	**Addition to Non-Derivative Sub-Account ($M)** (line 7 - line 8)		85.8

Notes:
1 Bruce Lease Net Revenues are discussed in Ex. G2-2-1.
2 Bruce Lease net revenues are from Ex.L-1.0-1 Staff-2, Table 39, col. (a), line 31, as increased by $1.6M to Canadian GAAP basis. The adjustment is discussed in Ex. A2-1-1 Section 4.0.
3 Per EB-2012-0002 Payment Amounts Order, App. B, p. 11-12, amount is determined as the annual average (at $11.30M/month) of Bruce Lease net revenues reflected in the EB-2010-0008 approved revenue requirement (EB-2010-0008 Payment Amounts Order, App. A, Table 2, line 20).
4 Represents the average of 2011 and 2012 annual nuclear production from EB-2010-0008 Payment Amounts Order, App. A, Table 3, line 1.
5 From Ex. L-1.0-1 Staff-002, Att. 1, Table 14, col. (d), line 3.
6 From Ex. L-1.0-1 Staff-002, Att. 1, Table 36, col. (a), line 30.

Table 14
(Updated version of Ex. H1-1-1 Table 14)
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - Actual 2013

Line No.	Particulars	Note	Actual 2013
			(a)
1	**Nuclear Rider 2013-A ($/MWh)**	1	6.27
2	**Nuclear Rider 2013-B ($/MWh)**	2	0.41
3	**Interim Nuclear Rider ($/MWh)**	3	4.33
4	**Interim Period Production Forecast (TWh)**	4	9.0
5	**Nuclear Actual Production for Jan-Feb 2013 (TWh)**		8.0
6	**Production Variance (TWh)** (line 4 - line 5)		1.0
7	**Under Recovery Due to Difference in Interim Period Production ($M)** (line 3 x line 6)		4.4
8	**Full Year Nuclear Forecast Production Used to Set Rider 2013-A (TWh)**	5	51.0
9	**Nuclear Production Forecast Used to Set Rider 2013-A for Mar-Dec 2013 (TWh)** (line 8 - line 4)		42.0
10	**Actual Mar-Dec 2013 Nuclear Production (TWh)**		36.7
11	**Actual Mar-Dec 2013 Nuclear Production Variance (TWh)** (line 9 - line 10)		5.3
12	**Under Recovery Due to Difference in Mar-Dec 2013 Production ($M)** (line 11 x (line 1 + line 2)		35.1
13	**Addition to Variance Account ($M)** (line 7 + line 12)		39.5

Notes:
1 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (g), line 13.
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 7.
3 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 2.
4 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 5.
5 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (g), line 12.

SCHEDULE OF SELECT REGULATORY BALANCES
AS AT DECEMBER 31, 2013

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. ("OPG") receives regulated prices for electricity generated from its hydroelectric generation facilities and all of the nuclear generation facilities it operates. OPG's regulated prices for the generation from these facilities are determined by the Ontario Energy Board ("OEB").

The OEB's decisions and orders have authorized OPG to establish certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The balances in these accounts are calculated in accordance with these decisions and orders and *Ontario Regulation 53/05*. In accordance with United States generally accepted accounting principles ("US GAAP"), OPG's consolidated financial statements recognize regulatory assets and liabilities for balances in the variance and deferral accounts.

In its March 2013 decision and April 2013 order approving a settlement agreement between OPG and interveners on OPG's application under case number EB-2012-0002, the OEB approved the balances in most accounts as at December 31, 2012. Pursuant to the approved settlement agreement, the review of certain accounts was deferred as part of that proceeding. These accounts are being brought forward for review and disposition in OPG's application for new regulated prices filed with the OEB in September 2013 under case number EB-2013-0321. The application includes a request to approve for disposition the balances in these accounts as at December 31, 2013 through new rate riders effective January 1, 2015.

The balances in the brought forward variance accounts as at December 31, 2013 are comprised of account additions and interest on account balances recorded by OPG during the period from January 1, 2011 to December 31, 2013. Interest was recorded at the rate of 1.47 percent per annum prescribed by the OEB. As at December 31, 2013, the balances to be recovered from (refunded to) ratepayers in the accounts brought forward for disposition in OPG's application to the OEB under case number EB-2013-0321 were as follows:

(millions of dollars)	**2013**
Hydroelectric Surplus Baseload Generation Variance Account	**19**
Hydroelectric Incentive Mechanism Variance Account	**(5)**
Capacity Refurbishment Variance Account – Hydroelectric	**113**
Capacity Refurbishment Variance Account – Nuclear – Capital Portion	**6**
Nuclear Development Variance Account	**57**

This schedule of regulatory balances has been prepared solely for the use of OPG's management and for filing with the OEB, and is considered by OPG's management to be a fair and reasonable representation of the balances in the variance accounts brought forward for disposition in OPG's application under case number EB-2013-0321. These balances have been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.

[Original signed by]

Robin Heard
Interim Chief Financial Officer

February 14, 2014

See accompanying note to the schedule

NOTE TO THE SCHEDULE OF SELECT REGULATORY BALANCES AS AT DECEMBER 31, 2013

1. BASIS OF ACCOUNTING

The schedule of select regulatory balances presents the balances in the Hydroelectric Surplus Baseload Generation Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the nuclear capital and hydroelectric portions of the Capacity Refurbishment Variance Account, and the Nuclear Development Variance Account of OPG as at December 31, 2013. These balances represent the regulatory assets and liabilities recorded by OPG in accordance with US GAAP for the purposes of its consolidated financial statements, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers. For the purposes of its consolidated financial statements prepared in accordance with US GAAP, as required by FASB Accounting Standards Codification ("ASC") 980, *Regulated Operations,* OPG limits the portion of cost of capital additions recognized as a regulatory asset or liability to the amount calculated using the average rate of capitalized interest applied by OPG to construction and development in progress. All dollar amounts are presented in Canadian dollars.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that incurred costs in respect of regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in its consolidated financial statements. When OPG is required to refund amounts in respect of regulated facilities to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, OPG records a regulatory liability in its consolidated financial statements. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

OPG's most recent annual consolidated financial statements filed with the Ontario Securities Commission ("OSC") are as at and for the year ended December 31, 2012. OPG's most recent interim consolidated financial statements are as at and for the nine months ended September 30, 2013 and have been filed with the OSC.

INDEPENDENT AUDITORS' REPORT

To the management of **Ontario Power Generation Inc.**

We have audited the accompanying schedule of select regulatory balances of **Ontario Power Generation Inc.** as at December 31, 2013 (the "Schedule"). The Schedule has been prepared by management to present the balances of the Hydroelectric Surplus Baseload Generation Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the nuclear capital and hydroelectric portions of the Capacity Refurbishment Variance Account, and the Nuclear Development Variance Account of **Ontario Power Generation Inc.** authorized for **Ontario Power Generation Inc.** by the decisions and orders of the Ontario Energy Board, in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers, as described in Note 1 to the Schedule.

Management's responsibility for the schedule of select *regulatory balances*
Management is responsible for the preparation and the fair presentation of this Schedule in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers, as described in Note 1 to the Schedule, and for such internal control as management determines is necessary to enable the preparation of the Schedule that is free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on the Schedule based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Schedule is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Schedule. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the Schedule, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the Schedule in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Schedule.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the Schedule presents fairly, in all material respects, the balances of the Hydroelectric Surplus Baseload Generation Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the nuclear capital and hydroelectric portions of the Capacity Refurbishment Variance Account, and the Nuclear Development Variance Account of **Ontario Power Generation Inc.** as at December 31, 2013 authorized for **Ontario Power Generation Inc**. by the decisions and orders of the Ontario Energy Board, in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers as, described in Note 1 to the Schedule.

Basis of accounting and restriction on distribution
Without modifying our opinion, we draw attention to Note 1 to the Schedule, which describes the basis of accounting. The Schedule is prepared solely for the use of **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process. As a result, the Schedule may not be suitable for another purpose.

Our auditors' report is intended solely for **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process and should not be used for any other purpose.

[Original Signed by]

TORONTO, CANADA
February 14, 2014

ERNST & YOUNG LLP
Chartered Accountants
Licensed Public Accountants

Board Staff Interrogatory #182

Ref: Exh. H1-1-1 page 7 and Tables 1 and 12 and Exh. H1-2-1 Table 2

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

With respect to the Capacity Refurbishment Variance Account, OPG states "Table 12 also presents the projected 2013 nuclear non-capital cost account additions, which OPG is not seeking to clear in this application." The EB-2012-0002 proceeding determined that this account would be cleared in the next payment proceeding.

a) Please confirm that OPG is not seeking to recover either the total nuclear non-capital cost projected account balance of $25.4M or the projected nuclear non-capital cost account additions (transactions) of $20.6M as at the 2013 year-end 2013.

b) Please provide the reasons for not clearing the identified amount noted above in this proceeding.

Response

a) OPG notes that $4.7M (Ex. H1-2-1 Table 2, line 5, column b) has already been approved for recovery during 2014 by the OEB in EB-2012-0002. OPG confirms that it is not seeking to recover either the total actual nuclear non-capital cost account balance or the actual nuclear non-capital cost account additions (transactions) as at the 2013 year-end as part of this application.

   OPG seeks to clear only "...the capital cost portion of the nuclear balance in the Capacity Refurbishment Variance Account..." as part of this application. (Ex. H1-2-1, page 1, lines 21 to 23.) OPG seeks to clear only this portion of the account as it was this portion of the account that was deferred for clearance in EB-2012-0002 and required to be brought forward in the next (this) application.

b) Please see Ex. L-09.6-1 Staff-191, which is the response to Board Staff Interrogatory 191.

Board Staff Interrogatory #183

Ref: Exh H1-1-1 page 12 and Table 11 and Exh. F2-8-1 page 5, Table 1

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

With respect to the Nuclear Development Variance Account,

a) For the projected 2013 recorded transactions of $38.6M, does this amount include only incremental labour costs which were clearly not included in approved OM&A costs in the last payment proceeding?

b) For the labour costs in 2011, 2012 and 2013, please provide a detailed breakdown of the costs for each year by their nature and purpose, the amounts, the suppliers and proof of payments to parties.

Response

a) Amounts included in the Nuclear Development Variance Account are incremental and were not included in the approved OM&A costs. As described in previous OPG evidence, (EB-2012-0002, Ex. L-1-7 SEC-18, p. 1):

> There were no cost reductions in other areas of OPG's operations to fund spending on NND because, as noted above, OPG explicitly indicated that these costs would be recovered through the Nuclear Development Variance Account, absent the creation of an alternative funding mechanism, which did not occur.

A revised Table 1, NND expenditures by Resource Type 2011 – 2013, has been provided below that includes the actual expenditures for all three years.

Table 1

2011 - 2013 Combined ($M)	Labour	Overtime	Augmented Staff	Materials	Other Contracted services	Licensing fees	Other	Total
Regulatory Hearings	1.6	0.1	-		1.1	-	-	2.8
Regulatory Compliance	3.9		-	-	9.2	8.4	0.2	21.7
Site Readiness	1.9	-	-		2.4	-	0.1	4.4
Vendor Analysis/Project Planning	5.4		0.5	-	28.9	-	0.5	35.3
Stakeholder Consultation	0.9	-	-		3.0	-		3.9
Total	13.7	0.1	0.5	0.0	44.6	8.4	0.8	68.1

b) For new nuclear, labour costs are associated with both OPG staff and Other Contracted Services.

i) For OPG staff, labour costs incurred in 2011, 2012, and 2013 has been provided in Table 2 below. The labour costs represent compensation paid to OPG employees only and the overheads and other costs associated with their employment.

Table 2

Labour by year $M:	2011	2012	2013
Regulatory Hearings	1.6		
Regulatory Compliance	1.4	1.7	0.8
Site Readiness	1.3	0.6	
Vendor Analysis/Project Planning	1.4	2.1	1.9
Stakeholder Consultation	0.5	0.3	0.1
Total :	6.2	4.7	2.8

These costs by year include labour for approximately 40 FTEs for 2011, 23 FTEs for 2012, and about 11 FTEs for 2013.

ii) Table 1 above provides a breakdown of the Other Contracted Services in 2011, 2012, and 2013 by Resource Type. Suppliers used in Regulatory Hearings include environmental assessment specialists and legal counsel. Suppliers involved in Regulatory Compliance include consulting engineering firms, and conservation authorities. Suppliers involved in Site Readiness include consulting engineering firms and construction firms. For Vendor Analysis/Project Planning, suppliers include legal counsel, quality management specialists, consulting engineering firms, and SNC-Lavalin Nuclear Inc./Candu Energy Inc., and

Westinghouse Electric Canada, Inc. The Stakeholder Consultation includes a $3.0m payment under the Clarington Host Agreement, as mentioned in the pre-filed evidence (Ex. F2-8-1, p. 4).

Table 3 below provides the list of suppliers providing Other Contract Services to OPG in support of new nuclear by year.

Table 3
Other Contracted Services by Year and Listed Suppliers

2011 **$ 7.0 m**	**2012** **$ 16.9 m**	**2013** **$ 20.7 m**
Supplier	Supplier	Supplier
AECL	AMEC	AMEC
AECON	ARCHI Services	Beacon
AMEC	Beacon	Bird Studies Canada
ARCHI Services	Bird Studies Canada	Black & McDonald
Beacon	Black & McDonald	CH2M
Bird Studies Canada	CH2M	ES Fox Limited
Black & McDonald	Clarington	Quinte Conservation Authority
Calm	ES Fox Limited	SENES
CH2M	NEXT Career Services	SNC Lavalin Nuclear/Candu
CONNELLY	Quinte Conservation Authority	Torys
CPUS	SENES	UTI
Garrod Pickfield	SNC Lavalin Nuclear/Candu	WAG QA Services
Hope United Church	Torys	Westinghouse Canada
HydroOne	UTI	
Kinetrics	WAG QA Services	
Miller Thomson	Westinghouse Canada	
MPR ASSOCIATE		
MTO/URS Corp		
SENES		
Torys		
Univ of Western Ontario		
WAG QA Services		

OPG confirms that all invoices from the listed suppliers received have been paid.

Board Staff Interrogatory #184

Ref: Exh. H1-1-1 page 12 and Table 11

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

With respect to the Nuclear Development Variance Account,

a) Please explain why OPG is seeking to recover from ratepayers the amounts recorded in the Nuclear Development Variance Account given that the planned new nuclear plants are being discontinued.

b) Please provide any regulatory precedents that have allowed development costs to be recovered for discontinued development of facilities.

Response

a) The premise of this question being that "the planned new nuclear plants are being discontinued" is incorrect. Plans to construct the new nuclear units have not been discontinued. Therefore, activities to support the construction of new nuclear units have not been discontinued. The timing of the commencement of construction related activities has been deferred until such time as the energy supply and demand forecast for Ontario indicates that new nuclear is required, as indicated in Government of Ontario's Long-term Energy Plan of December 2013 (the "2013 LTEP")

The LTEP can be found at http://www.energy.gov.on.ca/en/ltep/

The amounts that have been included in the Nuclear Development Variance Account to-date were incurred by OPG in fulfillment of the direction that had been provided in the previous LTEP and Supply Mix Directives that had been issued by the Minister of Energy. Most recently in March 2011 [Ex. D2-2-1, Attachment 1], the Minister indicated to OPG that:

> "Due to the long lead times involved in nuclear procurement and construction, it is essential for OPG to continue with the environmental assessment and site licensing process currently underway to ensure that we are ready to construct the new units following selection of a preferred vendor." [page 2]

As noted in Ex. F2-8-1, page 2, the 2013 LTEP consultation document continued to include new nuclear as a supply option for Ontario.

A decision was made by the Government of Ontario in late 2013 to defer the construction of new nuclear:

> Nuclear generation will continue to be the backbone of Ontario's supply, and we have confirmed our commitment to nuclear with the refurbishment of the Bruce and Darlington sites. Due to the strong supply situation, *we have deferred the construction of new nuclear generating units*. (2013 LTEP, page 3) (emphasis added).

The Government of Ontario provides specific direction respecting new nuclear on page 29 of the 2013 LTEP:

> Ontario continues to have the option to build new nuclear reactors in the future, should the supply and demand picture in the province change over time. The ministry will work with OPG to maintain the licence granted by the Canadian Nuclear Safety Commission, to keep open the option of considering new build in the future.

b) As the construction of new nuclear units has not been discontinued, regulatory precedents for recovery of development costs related to discontinued facilities are not relevant for recovery of the year-end 2013 amounts in the Nuclear Development Variance Account.

Board Staff Interrogatory #185

Ref: Exh. H1-1-1 Table 7

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Please provide a detailed calculation showing the derivations of the 2013 projected amounts (to be updated to reflect 2013 actual, if applicable) for “Increase Regulatory Taxable Income” (line 8 column c) and Niagara Tunnel Project - Income Tax Impact (line 9 column c).

Response

The chart below provides the derivations for the 2013 actual amounts shown in L-9.1-17 SEC-132, Attachment 1, Table 7, col. (c), lines 8 and 9 for “Increase in Regulatory Taxable Income” and “Niagara Tunnel Project – Income Tax Impact”, correspond to the projected 2013 amounts shown in Ex. H1-1-1, Table 7, col. (c), lines 8 and 9.

1 **Calculation of Increase in Regulatory Taxable Income and Income Tax Impact ($M)**
2

Line No.	Particulars	Reference	Actual 2013
			(b)
1	**Net Plant Amount Not Reflected in Rate Base**	L-9.1-17 SEC 132, Att. 1, Table 7, col. (c), line 3	1,123.0
2	**Board Approved Equity Ratio**	Note 1	47%
3	**Board Approved Return on Equity**	Note 2	9.55%
4	**Return on Equity Variance**	line 1 x line 2 x line 3	50.4
5	**Depreciation Variance**	L-9.1-17 SEC 132, Att. 1, Table 7, col. (c), line 6	12.7
6	**CCA Variance**	L-9.1-17 SEC 132, Att. 1, Table 7, col. (c), line 7	(4.5)
7	**Increase in Regulatory Taxable Income** (lines 4 + 5 + 6)		58.7
8	**Tax Rate**	L-9.1-17 SEC 132, Att. 1, Table 7, Note 4, col. (h), line 4a	25%
9	**Niagara Tunnel Project – Income Tax Impact**	(line 7 x line 8) / (1- line 8)	**19.6**

3
4 Note 1: From EB-2010-0008 Payment Amount Order, App A Table 5b, col. (b), line 5.
5 Note 2: From EB-2010-0008 Payment Amount Order, App A Table 5b, col. (c), line 5.

Board Staff Interrogatory #186

Ref: Exh. H1-1-1 Table 12a

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Please provide a detailed calculation showing the derivations of the 2013 projected amounts (to be updated to reflect 2013 actual, if applicable) for "Increase Regulatory Taxable Income" (line 8 column c) and "Total Capital Addition to Variance Account" (line 11column c).

Response

The chart below provides the derivations for the 2013 actual amount shown in L-9.1-17 SEC-132, Attachment 1, Table 12a, line 8, col. (c) for "Net Increase in Regulatory Taxable Income", corresponding to the projected 2013 amount shown in Ex. H1-1-1, Table 12a, line 8, col. (c).

Calculation of Increase in Regulatory Taxable Income ($M)

Line No.	Particulars	Reference	Actual 2013
			(a)
1	**Net Plant Amount Not Reflected in Rate Base**	L-9.1-17 SEC 132 Att. 1, Table 12a, col. (c), line 1	60.2
2	**Board Approved Equity Ratio**	Note 1	47%
3	**Board Approved Return on Equity**	Note 2	9.55%
4	**Return on Equity Variance**	line 1 x line 2 x line 3	2.7
5	**Depreciation Variance**	L-9.1-17 SEC 132 Att. 1, Table 12a, col. (c), line 4	2.3
6	**CCA Variance**	L-9.1-17 SEC 132 Att. 1, Table 12a, col. (c), line 7	(11.3)
7	**Increase (Decrease) in Regulatory Taxable Income** (lines 4 + 5 + 6)	L-9.1-17 SEC 132 Att. 1 Table 12a, col. (c), line 8	**(6.3)**

Note 1: From EB-2010-0008 Payment Amount Order, App A Table 5b, col. (b), line 5.
Note 2: From EB-2010-0008 Payment Amount Order, App A Table 5b, col. (c), line 5.

As detailed in L-9.1-17 SEC-132, Attachment 1, Table 12a, line 11, col. (c) for the equivalent 2013 actual amount to that shown in Ex. H1-1-1, Table 12a, line 11, col. (c), the “Total Capital Addition to Variance Account “ is a summation of the cost of capital, depreciation, and income tax impact amounts in Ex L-0.1-17 SEC-132, Attachment 1, col. (c) at lines 3, 4 and 10.

Board Staff Interrogatory #187

Ref: Exh. H1-1-1 Table 5 (line 1 columns b and c) and Exh. E1-2-1 Page 3

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

With respect to the foregone production due to surplus baseload generation (SBG) conditions, please explain why the SBG spill volume for 2013 is projected to be 178.0 GWh (to be updated to reflect 2013 actual), which is 52 percent higher than the 116.9 GWh for 2012.

Response

The increase in planned 2013 SBG spill over 2012 actual SBG spill at the previously regulated hydroelectric assets was primarily due to the return to service of Bruce Units 1 and 2 in October 2012 which was projected to add approximately 1,500 MW of baseload supply throughout 2013.

Board Staff Interrogatory #188

Ref: Exh. H1-1-1 Table 5 (line 3 columns a, b and c)

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory
Please provide a detailed breakdown of the derivations of the Gross Revenue Charge/Water Rental Costs of $(1.1)M for 2011, $(1.7)M for 2012 and $(2.6)M for 2013.

Response

The requested derivations are shown below for 2011 and 2012. Also provided below is the derivation of the actual amount of $(10.1)M for 2013, which is shown in the response to L-9.1-17 SEC-132, Attachment 1, Table 5, col. c, line 3.

The derivations are as described in Ex. F1-4-1, section 3.0, whereby the GRC/water rental cost is determined by multiplying the station's annual energy production by a prescribed rate of $40/MWh and then applying a GRC property tax rate and a fixed water rental rate.

Line No.	Particulars	Actual Mar-Dec 2011	Actual 2012	Actual 2013
		(a)	(b)	(c)
1	**Prescribed GRC Revenue Rate ($/MWh)**	40.00	40.00	40.00
2	**GRC Property Tax Rate for annual generation >700 GWh**[1]	26.5%	26.5%	26.5%
3	**GRC Water Rental Tax Rate**	9.5%	9.5%	9.5%
4	**Total GRC Tax Rate** (line 2 + line 3)	36.0%	36.0%	36.0%
5	**Total GRC Rate ($/MWh)** (line1 x line 4)	14.40	14.40	14.40
6	**Actual/Projected Foregone Production Due to SBG Conditions**[2] **(GWh)**	76.5	116.9	698.7
7	**GRC/Water Rental Costs ($M)** (line 5 x line 6)	**1.1**	**1.7**	**10.1**

[1] The highest GRC property tax rate is applied as production from the Beck facilities reaches the 700 GWh threshold during January of each year.
[2] From L-9.1-17 SEC 132, Attachment 1Table 5, line 1.

Board Staff Interrogatory #189

Ref: Exh. H1-1-1 Table 5 (line 5), Table 7 (line 15), Table 12a (line 12)

Issue Number: 9.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

The referenced tables in the specified lines are entitled "Financial Reporting Adjustment" and their associated footnotes state: "Represents offsetting interperiod financial statement reconciliation adjustments which do not impact the total transactions in the account over the 2011-2012 period."

a) Please provide an explanation for and identify of the nature of the "Financial Reporting Adjustment" for each of the lines noted-above in relation to the specific tables.
b) Was the "Financial Reporting Adjustment" for each account's balance reflected in OPGs financial statements including the nature of accounting adjustments and any note disclosures? If so, please provide the details.

Response

a) As noted in the footnotes to the referenced line items in the corresponding tables, the financial reporting adjustments represent offsetting inter-period financial statement reconciliation adjustments. They are included as an adjustment to the total account additions for a particular period in the applicable Ex. H1-1-1 tables because those tables present the calculation of account additions in the period to which the additions relate, which, in limited instances, have not been recognized in the financial statements until a subsequent period. The calculations are presented in the Application in the period to which they relate to enable a review of the additions that is transparent and consistent with the manner in which the rest of the evidence is presented. There is no overall impact of these adjustments on the balance of the account, including interest which is calculated on the basis of the period to which account additions relate.

   Specifically, the differences in the timing of financial statement recognition for the Hydroelectric Surplus Baseload Generation Variance Account (Ex. H1-1-1, Table 5 and Ex. L-9.1-17 SEC-132, Table 5) resulted from an adjustment to the 2011 estimated foregone production at the regulated facilities due to SBG (i.e. SBG spill). The adjustment reflected a refinement to OPG's SBG spill reporting methodology (discussed in Ex. E1-2-1) in 2012, based on a review of the management of spill operation and accumulated data since March 2011. The impact of the adjustment was recognized in OPG's 2012 audited consolidated financial statements.

   For the Hydroelectric Capacity Refurbishment Variance Account (Ex. H1-1-1, Table 7 and Ex. L-9.1-17 SEC-132, Table 7), the differences in the timing of financial statement recognition primarily result from the recording in 2013 of net ratepayer credits related to the variances associated with the Sir Adam Beck I Generating Station Unit 3 Upgrade project and the Sir Adam Beck I Generating Station Unit 9 Upgrade project, for the period from April 1, 2008 to December 31, 2013. OPG determined in 2013 that, as these projects are similar in nature to the Sir Adam Beck I Generating Station Unit 7 Frequency Conversion project reflected in the Capacity Refurbishment Variance Account, it was appropriate to credit the ratepayers with the associated variances. The liability for these ratepayer credits was reflected in OPG's 2013 audited consolidated financial statements. The minimal adjustments for Nuclear Capacity Refurbishment Variance Account (Ex. H1-1-1, Table 12a and Ex. L-9.1-17 SEC-132, Table 12a) relate to a refinement in the income tax calculation.

b) As discussed in part a), OPG confirms that the financial reporting adjustments for all accounts were reflected in the corresponding audited consolidated financial statements of OPG. These amounts did not require financial statement disclosure in accordance with US GAAP.

Board Staff Interrogatory #190

Ref: Exh. H1-3-1 pages 12-13

Issue Number: 9.5
Issue: Is the proposed continuation of deferral and variance accounts appropriate?

Interrogatory

Regarding the Bruce Lease Net Revenues Variance Account,

a) As the basis for its continuation, please confirm that the operation and accounting procedures including the disposition mechanism of the account is consistent with the approved Settlement Agreement reflected in the EB-2012-0002 Payment Amounts Order.

b) Please confirm that the operation and accounting procedures including the disposition mechanism of the account is ongoing effective January 1, 2013.

Response

a) Confirmed.

b) Confirmed until otherwise ordered by the OEB.

SEC Interrogatory #133

Ref: H1-1-1/Table 2

Issue Number: 9.5
Issue: Is the proposed continuation of deferral and variance accounts appropriate?

Interrogatory

Please explain why it is appropriate to measure the variance in water conditions using hydroelectric production, rather than variations in water flow.

Response

Water flows are used as the basis for determining the hydroelectric water conditions variances. Forecast river flows used in the energy production model for determining the forecast energy production plans are replaced with actual river flows and the model re-executed (with no changes to any other parameters). These computed production results, determined using actual flows, are then compared with the forecast production results to determine the production variances that are attributable solely to changes in flows. Revenue and cost variances associated with the computed production variances can then be calculated.

SEC Interrogatory #134

Ref: H1-3-1/p.9

Issue Number: 9.5
Issue: Is the proposed continuation of deferral and variance accounts appropriate?

Interrogatory

Please confirm that amounts in the Pension and OPEB Cost Variance Account – Future Recovery and 2013 Additions components - are not current cash costs. Please explain why interest should be charged on those amounts.

Response

Not confirmed.

Amounts recorded in the Pension and OPEB Cost Variance Account are the same as amounts recorded in any other deferral and variance account. They represent differences between the OEB-approved amount of costs and the actual amounts, determined on the same basis as the approved amounts. These differences represent cash amounts over or under-collected by OPG, and therefore carry with them an associated financing cost. In other words, as OPG noted in EB-2012-0002 Ex. L-3-7 SEC-30, it is the incidence of over or under-collection of revenues by the utility, not the nature of the items that has been over or under-collected, that is the general basis for recording interest on deferral and variance account balances.

The OEB's EB-2011-0090 Decision and Order originally authorized OPG to record interest on the Pension and OPEB Cost Variance Account balance in the same manner as OPG's other deferral and variance accounts. It is only as a result of the negotiated temporary suspension of interest charges on the majority of the account balance (other than the Historic Recovery portion) per the EB-2012-0002 Settlement Agreement that no interest is being recorded in this account in 2013 and 2014. The nature and scope of the account remain as established in EB-2011-0090 and, therefore, OPG sees no reason to deviate from the OEB's original decision.

VECC Interrogatory #007

Ref: H1-3-1, page 11

Issue Number: 9.5
Issue: Is the proposed continuation of deferral and variance accounts appropriate?

Interrogatory

It appears to VECC, based on the description of the Nuclear Liability Deferral Account in Exhibit H1 Tab 3 Schedule 1 Page 11, that it is OPG's proposal to continue to operate the account within the confines of the legislation that originally created the account, despite the fact that OPG benefited from a reduction in its Nuclear Liability in relation to the Darlington Refurbishment Project in 2010 that was not captured in the Nuclear Liability Deferral Account such that ratepayers did not benefit from the reduction (as noted in EB-2010-008, Decision dated March 10, 2011, page 73), and despite the fact that OPG and intervenors agreed by way of settlement in EB-2012-0002 (Exhibit M pages 17-19) to reflect reductions related to reduced Nuclear Liabilities to the benefit of ratepayers beyond what may have automatically been recorded in the Account.

a) Please confirm that VECC's understanding of OPG's proposal regarding the Nuclear Liability Deferral Account is correct and that OPG is not proposing a mechanism to capture reductions in Nuclear Liability amounts that OPG can benefit from but which would not be captured by the account as proposed.

b) If so confirmed, please advise whether OPG would object to an expanded scope for the account, or a supplemental account, to capture reductions in Nuclear Liability relative to the amounts embedded in rates so that the benefits of such reductions can be passed on to ratepayers in the absence of an "approved reference plan" that supplants the plan that prevailing rates reflect; if OPG does object to such an expansion of the scope of the account or to a supplemental account please provide OPG's reasons for its objection.

Response

a) Confirmed. OPG is not proposing changes to the structure of the Nuclear Liabilities Deferral Account. However, consistent with the terms of the Settlement Agreement (at page 29), OPG will address the concerns raised in the question through accounting order applications (see part b) for a further discussion).

Separately, OPG notes that VECC's characterization of the Settlement Agreement in EB-2012-0002 (Exhibit M, pages 17-19) is not correct. As noted below, neither of the matters discussed at pp. 17 - 19 of the Settlement Agreement relate to the impact on nuclear liabilities addressed by the OEB in EB-2010-0008, that being a change in OPG's Nuclear Liabilities resulting from an accounting change, rather than a change in the ONFA Reference Plan.

Clarifications:

1) As noted on page 18 of EB-2012-0002, Ex. M1-1, the Settlement Agreement provided for "an ***advancement*** of an estimated credit of $81.4M arising from the revenue requirement impact of Nuclear Liabilities for the prescribed facilities (other than reduction in depreciation expense associated tax impacts for the non-asset retirement cost components)." [emphasis added] This impact was always going to be recorded by OPG in the Nuclear Liability Deferral Account in 2013. The Settlement Agreement simply required this impact to be refunded to ratepayers earlier.

2) As also noted on page 18 of EB-2012-0002 Ex. M1-1, the Settlement Agreement provided for "an adjustment of $46.9M per year for the lower depreciation expense and associated lower income taxes in relation to the ***non-asset retirement cost*** components of the Pickering fixed asset balances" resulting from changes to the average service lives, for depreciation purposes, of the Pickering nuclear generating stations. [emphasis added] As such, this aspect of the agreement is in relation to impacts that are not related to Nuclear Liabilities and therefore the Nuclear Liability Deferral Account.

b) The EB-2012-0002 Settlement Agreement (Ex. M1-1, page 29) requires OPG to seek an accounting order from the OEB in the circumstances contemplated by the question. Specifically, the obligation applies when there is a revenue requirement impact for the prescribed facilities arising from an accounting change affecting the calculation of OPG's Nuclear Liabilities, where these impacts are not included in the current or proposed payment amounts and are not in the scope of the Nuclear Liability Deferral Account. OPG will honour this aspect of the Settlement Agreement, subject to materiality considerations applicable to such accounting order applications. This obligation is not limited to circumstances where the revenue requirement is a credit to ratepayers, but is symmetrical and encompasses impacts that would need to be recovered by OPG.

Board Staff Interrogatory #191

Ref: Exh. H1-2-1 Tables 1 and 2

Issue Number: 9.6
Issue: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Interrogatory

In cost of service proceedings, the Board's policy generally requires utilities to bring forward all balances in deferral and variance accounts for review and disposition. Please provide the reasons all accounts other than the four required by the decision and order in last the proceeding (EB-2012-0002) are not being proposed for clearance in this proceeding.

Response

OPG chose to clear all accounts other than the four required by the decision and order in EB-2012-0002 through a separate application to be filed later in 2014 because: (i) these accounts had recently been reviewed (i.e., during 2013) and a rate rider for these accounts had already been established for 2014; and, (ii) it decreased the scope of the current case, making it somewhat more manageable.

Board Staff Interrogatory #192

Ref: Exh. H1-2-1 Tables 1 and 2

Issue Number: 9.6
Issue: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Interrogatory

Please provide revised rate riders based on the disposition of all balances in deferral and variance accounts consistent with the recovery period used in Tables 1 and 2 of Exh H1-2-1. In addition, please provide the revised bill impact on customers consuming electricity of 800 kWh/month.

Response

Calculations of rate riders, using the assumptions in this question, are provided in Tables 1 and 2 in Attachment 1 to this response. The calculations are based on actual year end 2013 account balances as reported in Ex L-09.1-17 SEC-132 and production forecasts as updated in Ex. N1-1-1.

The question requires the use of recovery periods consistent with those proposed in OPG's application. In its application, OPG proposes a 24-month recovery for one account balance and a 12-month recovery for the others. Disposition of all accounts required certain assumptions regarding recovery periods. For purposes of this response, recovery periods are assumed as follows:

- Accounts with balances over $100M are recovered over 24 months with the following two exceptions;
  - The balance in the Pension and OPEB Cost Variance - Nuclear – Future account is recovered over 120 months which is the period remaining per the Settlement Agreement in EB-2012-0002.
  - In accordance with the Settlement Agreement in EB-2012-0002, clearance of the derivative sub account of the Bruce Lease Net Revenues Variance account is to be accomplished using OPG's forecast of payouts to Bruce Power rather than by straight line amortization of the balance over a set period of time. For purposes of this response, OPG has used $79.8M (Ex. G2-2-1 Table 8 line 15 col. c) less tax thereon at 25% for a net of $59.9M for the year 2015.
- All other balances are recovered over 12 months.

The resulting Previously Regulated Hydroelectric rider is $5.29/MWh.

The resulting Nuclear rider is $12.60/MWh.

Using the hypothetical riders from above, and the base payment amounts in the Application, the estimated bill impact on a typical residential customer consuming electricity of 800 kWh/month is $7.60/month as compared to the $5.94/month shown in Ex. N1-1-1.

Numbers may not add due to rounding.

Table 1
(Updated version of Ex. H1-2-1 Table 1)
Calculation of Deferral and Variance Account Recovery Payment Rider - Previously Regulated Hydroelectric ($M)

Line No.	Account	Actual Balance at December 31, 2013[1]	EB-2012-0002 Board Approved Amortization 2014[2]	(a)-(b) Actual 2013 Balance Less 2014 Approved Amortization	Recovery Period (Months)	Amortization 2015[3]	(c)-(e) Unrecovered Balance at December 31, 2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Hydroelectric Water Conditions Variance**	22.4	6.8	15.6	12	15.6	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	15.8	13.6	2.2	12	2.2	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(5.0)	0.0	(5.0)	12	(5.0)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	19.2	0.0	19.2	12	19.2	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(1.1)	(1.0)	(0.1)	12	(0.1)	0.0
6	**Tax Loss Variance - Hydroelectric**	19.7	19.3	0.5	12	0.5	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	112.7	0.0	112.7	24	56.4	56.4
8	**Pension and OPEB Cost Variance - Nuclear - Historic**	1.0	1.0	0.0	12	0.0	0.0
9	**Pension and OPEB Cost Variance - Nuclear - Future**	11.3	0.8	10.5	120	1.1	9.5
10	**Pension and OPEB Cost Variance - Nuclear - 2013 Additions**	18.6	0.0	18.6	12	18.6	0.0
11	**Impact for USGAAP Deferral - Hydroelectric**	1.2	1.1	0.0	12	0.0	0.0
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	1.3	(1.5)	2.9	12	2.9	0.0
13	**Total** (lines 1 though 12)	217.3	40.2	177.2		111.3	65.8
14	**Forecast 2015 Production[4] (TWh)**					21.0	
15	**Previously Regulated Hydroelectric Payment Rider ($/MWh)** (line 13 / line 14)					5.29	

Notes:
1 From L-9.1-17 SEC 132, Attachment 1, Table 1 col. (h).
2 From EB-2012-0002 Payment Amounts Order Appendix B, Table B-1, with the exception of lines 3, 4, 7 and 10. OPG is not proposing any additional amortization for 2014 in this application.
3 Amount is col. (c) amount x 12 months / recovery period in col. (d).
4 From Ex. N1-1-1 p. 20, Chart 10, col (a), line 5.

Numbers may not add due to rounding.

Table 2
(Updated version of Ex. H1-2-1 Table 2)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Actual Balance at December 31, 2013[1]	EB-2012-0002 Board Approved Amortization 2014[2]	(a)-(b) Actual 2013 Balance Less 2014 Approved Amortization	Recovery Period (Months)	Amortization 2015[3]	(c)-(e) Unrecovered Balance at December 31, 2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Nuclear Liability Deferral**	254.0	49.9	204.1	24	102.1	102.1
2	**Nuclear Development Variance**	56.5	0.0	56.5	12	56.5	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.9	0.7	1.3	12	1.3	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	5.7	0.0	5.7	12	5.7	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	8.9	4.7	4.1	12	4.1	0.0
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	214.4	27.0	187.4	N/A	50.9	136.5
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account**	138.1	15.0	123.2	24	61.6	61.6
8	**Income and Other Taxes Variance - Nuclear**	(17.9)	(13.0)	(4.9)	12	(4.9)	0.0
9	**Tax Loss Variance - Nuclear**	103.8	101.3	2.5	12	2.5	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Historic[4]**	20.7	20.9	(0.2)	12	(0.2)	0.0
11	**Pension and OPEB Cost Variance - Nuclear - Future**	231.8	17.2	214.7	120	21.5	193.2
12	**Pension and OPEB Cost Variance - Nuclear - 2013 Additions**	383.7	0.0	383.7	24	191.9	191.9
13	**Impact for USGAAP Deferral - Nuclear**	24.7	24.1	0.6	12	0.6	0.0
14	**Pickering Life Extension Depreciation Variance**	9.5	(37.5)	47.0	12	47.0	0.0
15	**Nuclear Deferral and Variance Over/Under Recovery Variance**	42.6	2.8	39.8	12	39.8	0.0
16	**Total** (lines 1 through 15)	1,478.4	213.0	1,265.4		580.2	685.2
17	**Forecast 2015 Production[5] (TWh)**					46.1	
18	**Nuclear Payment Rider ($/MWh)** (line 16 / line 17)					12.60	

Notes:
1 From L-9.1-17 SEC 132, Attachment 1, Table 1 col. (h).
2 From EB-2012-0002 Payment Amounts Order Appendix B, Table B-1, with the exception of lines 2, 4 and 12. OPG is not proposing any additional amortization for 2014 in this application.
3 Amount is col. (c) amount x 12 months / recovery period in col. (d).
4 The projected credit balance at December 31, 2015 does not reflect interest that will be recorded during 2014. Assuming no change in the OEB prescribed interest rate, the actual balance at December 31, 2014 would be expected to be close to zero.
5 From Ex. N1-1-1 p. 20, Chart 10, col (a), line 10.

CCC Interrogatory #025

Ref: Ex. A1/T3/S1, p. 3

Issue Number: 9.6
Issue: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Interrogatory

OPG has indicated that it only proposes to clear the audited, year-end 2013 balances for four accounts where review was deferred to a future proceeding in EB-2012-0002. Please explain, in detail, why OPG is limiting clearance to these four accounts, leaving the balances in the other accounts to be cleared through a separate application in 2014. What is the full range of options that OPG considered with respect to deferral and variance account clearances? For each option considered please explain why it was rejected?

Response

Please see Ex L-9.6-1 Staff 191.

PWU Interrogatory #024

Ref: Exh H1-1-1, Page1 of 15, Lines 24-25

> OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance account balances through a separate application to be filed in 2014.

Issue Number: 9.6
Issue: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Interrogatory

a) When in 2014 (which Quarter) does OPG anticipate to file this application?

Response

Q4.

SEC Interrogatory #135

Ref: H1-1-1/Table 1

Issue Number: 9.6
Issue: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Interrogatory

With respect to the deferral and variance accounts that the Applicant proposes not to clear in this proceeding:

(a) Please confirm that, pursuant to the Settlement Agreement and Board Order in EB-2012-0002:

i. The Pension and OPEB Cost Variance Account – Hydroelectric – Historic ($1.0 million) and the Pension and OPEB Cost Variance Account – Nuclear - Historic ($20.5 million) are being cleared pursuant to rate riders ending December 31, 2014.

ii. The Pension and OPEB Cost Variance Account – Hydroelectric – Future ($11.3 million) and the Pension and OPEB Cost Variance Account – Nuclear - Future ($231.8 million) are being cleared pursuant to rate riders ending December 31, 2024.

iii. The Tax Loss Variance Account – Hydroelectric ($19.8 million) and the Tax Loss Variance Account – Nuclear ($014.0 million) are being cleared pursuant to rate riders ending December 31, 2014.

iv. The Impact for USGAAP Deferral Account – Hydroelectric ($1.2 million) and the Impact for USGAAP Deferral Account – Nuclear ($24.8 million) are being cleared pursuant to rate riders ending December 31, 2014.

v. The Bruce Lease Net Revenues Derivative Sub-Account is being cleared pursuant to a specialize mechanism matching clearance to rebates of Supplemental Lease Revenues.

(b) Please explain why, consistent with the Settlement Agreement and Board Order in EB-2012-0002, the amounts in the Pension and OPEB Cost Variance Account – Hydroelectric – 2013 Additions ($21.5 million) and the Pension and OPEB Cost Variance Account – Nuclear – 2013 Additions ($375.9 million) are not being cleared over the next twelve years ending December 31, 2025, using the EARSL period approved in EB-2012-0002.

(c) Please advise whether the balance of $42.7 million in the Hydroelectric Water Conditions Variance Account is based on final data, or provide the final balance in the account. Please advise the amount that will be collected for this account in 2014 under the EB-2012-0002 Payment Amounts Order.

(d) Please advise whether the balance of $35.3 million in the Ancillary Services Net Revenue Variance Account - Hydroelectric is based on final data, or provide the final balance in the account. Please advise the amount that will be collected for this account in 2014 under the EB-2012-0002 Payment Amounts Order.

(e) Please advise whether the balance of $1.8 million in the Ancillary Services Net Revenue Variance Account - Nuclear is based on final data, or provide the final balance in the account. Please advise the amount that will be collected for this account in 2014 under the EB-2012-0002 Payment Amounts Order.

(f) Please explain why the Income and Other Taxes Variance Account – Hydroelectric (-$1.1 million) and the Income and Other Taxes Variance Account – Nuclear ($-14.7 million) should not be cleared in this proceeding. Please provide details of the "debit entry related to the portion of nuclear waste management expenditures deemed to be capital", including the year under audit, the initial position taken, and the resolution of the dispute.

(g) With respect to the Capacity Refurbishment Variance Account – Nuclear, please explain how the Darlington Energy Complex and the related Water and Sewer Projects should be considered used and useful in 2012 and/or 2013.

(h) Please confirm that, pursuant to the Settlement Agreement and Board Order in EB-2012-0002, the amount of $81.4 million "deferred" in the Nuclear Liability Account was to reflect a credit to that account with respect to the expected extension of the service lives of the Prescribed Facilities. Please explain why that credit has not reduced the balance in the account by that amount. Please advise the amount that will be collected for this account in 2014 under the EB-2012-0002 Payment Amounts Order.

(i) Please advise the amount that will be collected for the Bruce Lease Net Revenues – Non-Derivative Account in 2014 under the EB-2012-0002 Payment Amounts Order. Please explain why the Applicant is not proposing to recover additional amounts for the $87 million debit to the account in 2013.

(j) Please explain why it is not appropriate to recover the amount of $9.5 million in the Pickering Life Extension Variance Account in the current proceeding.

Response

(a) OPG confirms that, amortization amounts for deferral and variance account balances shown in Ex. H1-1-1, Table 1 (updated in L-9.1-17 SEC-132, Attachment 1, Table 1) are pursuant to the OEB-approved Settlement Agreement and Payment Amounts Order in EB-2012-2002, which approved the recovery of the December 2012 balances in the respective accounts. OPG also confirms that the regulated hydroelectric and nuclear rate raiders established in the Payments Amount Order issued by the OEB in April 2013, are effective up to December 31, 2014.

(b)
i. Confirmed.
ii. Confirmed.
iii. Confirmed, with the exception of interest recorded on the account balance accumulated during 2013, which is not being recovered through the EB-2012-0002 riders.
iv. Confirmed, with the exception of interest recorded on the account balance accumulated during 2013, which is not being recovered through the EB-2012-0002 riders.
v. Confirmed.

(c) Refer to Ex. L-9.6-1 Staff-191 for an explanation of OPG's proposal not to clear all account balances in this Application.

(d) The balance of $42.7M shown in Ex. H1-1-1, Table 1 was the projected 2013 ending balance. The actual balance as at December 31, 2013 is $22.4M, as shown in L-9.1-17 SEC-132, Attachment 1, Table 1, col. (h), line 1. As shown in Ex H1-2-1, Table 1, col. (b), line 1, $6.8M of the 2013 ending balance will be recovered in 2014 pursuant to the EB-2012-0002 Payment Amounts Order.

(e) The balance of $35.3M shown in Ex. H1-1-1, Table 1 was the projected 2013 ending balance. The actual balance as at December 31, 2013 is $15.8M as shown in Ex. L-9.1-17 SEC-132, Attachment 1, Table 1, col. (h), line 2. As shown in Ex H1-2-1, Table 1, col. (b), line 2, $13.6M of the 2013 ending balance will be recovered in 2014 pursuant to the EB-2012-0002 Payment Amounts Order.

(f) The balance of $1.8M shown in Ex. H1-1-1, Table 1 was the projected 2013 ending balance. The actual balance as at December 31, 2013 is $1.9M as shown in Ex. L-9.1-17 SEC-132, Attachment 1, Table 1, col. (h), line 16. As shown in Ex H1-2-1, Table 2, col. (b), line 3, $0.7M of the 2013 ending balance will be recovered in 2014 pursuant to the EB-2012-0002 Payment Amounts Order

(g) Refer to Ex. L-9.6-1 Staff-191 for an explanation of OPG's proposal not to clear all account balances in this Application.

As noted in EB-2012-0002, Ex. H1-1-1, section 4.2, the referenced entry results from certain cash expenditures for nuclear waste management and decommissioning, which OPG had treated as deductible when incurred, being deemed to be capital for tax purposes.

In general, OPG has been of the opinion that none of the costs incurred for nuclear waste management and decommissioning activities should be treated as capital for income tax purposes. During the audit of OPG's 2005 taxation year, the tax auditors, to a large extent, concurred with OPG's position but identified certain items, such as transportation trucks, that they believed should be capitalized for tax purposes. As a result, the costs for these items would not be deductible when incurred (increasing taxable income for that year) and instead result in additional Capital Cost Allowance deductions over time. OPG agreed to this treatment as part of the finalization of the 2005 audit in 2012 and has applied it to all years after 2005. The December 31, 2012 balance of the Income and Other Taxes Variance Account approved for disposition in EB-2012-0002 reflected the impact of this change for the period from April 1, 2008 to December 31, 2012. The actual amount of the 2013 entry was a credit of $0.2M, as shown at Ex. L-9.1-17 Staff-132, Attachment, Table 6, col. (c), line 13.

The forecast regulatory income taxes for 2014 and 2015 provided in this Application incorporate the impact of the above noted change in treatment.

(h) The Water and Sewer project is used and useful because it is providing immediate service to the Darlington station by providing domestic water supply and sewer services, mitigating existing adverse conditions discussed in Ex. D2-2-1, section 7.2.2.

The Darlington Energy Complex ("DEC") is used and useful because a substantial portion of its use relates to current and future ongoing nuclear operations. It not only provides office space and a training facility for Darlington Refurbishment staff, as well as a public information centre for the Darlington station. Further, nuclear services and records groups, which provide services to all of Nuclear, are located at the DEC. Upon completion of the DRP, the DEC is expected to house warehouse, office space, and training for the nuclear support functions, as discussed in Ex. D2-2-1, section 7.2.1 and Ex. L-4.11-17 SEC-067. As such, the DEC is considered to be in service, as reflected in OPG's 2013 audited consolidated financial statements prepared in accordance with GAAP. The same rationale applies to the Water and Sewer project.

(i) OPG confirms that pursuant to the Settlement Agreement and Payment Amounts Order, $81.4M of the Nuclear Liability Deferral Account was deferred for future recovery. This amount represents an advancement of the refund into the EB-2012-0002 riders of an estimated ratepayer credit of $81.4M that was going to be recorded in 2013. Contrary to the premise of the question, this credit is reflected in the actual 2013 additions of $122.7M to the Nuclear Liability Deferral Account, as calculated at Ex. L-9.1-17 SEC-132, Attachment 1, Table 10. The credit represents the estimated amount by which the debit account addition in 2013 is lower than it otherwise would have been in the absence of the nuclear station service life changes effective December 31, 2012.

(j) Pursuant to the EB-2012-0002 Payment Amounts Order, OPG will collect $15.0M for the Bruce Lease Net Revenues – Non-Derivative Sub-Account in 2014, as shown in Ex. H1-2-1, Table 2, col. (b), line 7. Refer to Ex. L-9.6-1 Staff-191 for an explanation of OPG’s proposal not to clear all account balances in this Application.

(k) Refer to Ex. L-9.6-1 Staff-191 for an explanation of OPG’s proposal not to clear all account balances in this Application.

Board Staff Interrogatory #193

Ref: Exh. H1-3-1 pages 1-15

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Regarding the proposal to make the existing variance accounts applicable to the newly regulated hydroelectric facilities,

a) Please provide a detailed explanation on how each account meets the Broad's qualification criteria of:
   i. Materiality
   ii. Causation
   iii. Prudence
   iv. Outside of Management's ability to control
b) Please explain why the proposal for the accounts should be included and operate as part of existing hydroelectric facilities.
c) If approved, will OPG report to the Board the specific balances of the sub-accounts within the existing hydroelectric variance accounts for greater transparency (rather than the rolled-up sub-account balances shown as one figure for each applicable account)? If not, please explain.

Response

Part a) and b)

OPG has proposed to extend the application of four variance accounts specific to hydroelectric operations and three common cost variance accounts (i.e., accounts that impact both hydroelectric and nuclear operations) to its newly regulated hydroelectric operations. These accounts have all been previously established by the OEB in EB-2010-0008 based on OPG's specific circumstances.

The continuing need for these accounts is discussed in Ex H1-3-1. OPG has provided the evidence reference in the chart below. The evidence references describing the need for these accounts for OPG's newly regulated operations is also provided in the chart below. In summary, there has been no change in OPG's circumstances since EB-2010-0008 associated with these accounts, the newly regulated hydro accounts are needed for the same reasons as the previously regulated hydroelectric accounts were established and continue to be used. With respect to the common cost variance accounts, the newly regulated hydro facilities are no different than the existing prescribed hydroelectric facilities and therefore should be assigned their portion of the common costs reflected in these variance accounts.

Variance Account Description	**Account Type**	**Ex H1-3-1 Reference: Why is it Needed?**	**Ex H-3-1 Reference: Why is it needed for Newly Reg. Hydro?**
Hydroelectric Water Conditions	Hydro	Page 2, Lines 22-26	Page 2, Lines 26-27, Page 3, lines 4-6
Ancillary Services Net Revenues-Hydroelectric	Hydro	Page 3, Lines 16-19	Page 3, Lines 19-20
Hydroelectric Surplus Baseload Generation	Hydro	Page 4, Lines 11-14	Page 4, Lines 14-15 Page 6, Lines 7-9
Hydroelectric Deferral and Variance Account over/Under Recovery	Hydro	Page 10, Lines 22-25	Page 10, Lines 26-29
Income and Other Taxes	Common	Page 6, Lines 18-30 Page 7, Lines 1-10	Page 7, Lines 19-21
Capacity Refurbishment	Common	Page 8, Lines 1-2	Page 8, Lines 2-8
Pension and OPEB Cost	Common	Page 8, Lines 22-27	Page 10, Lines 4-7

c) OPG’s proposal (Ex H1-3-1, Page 2) is that separate sub-accounts will be used to distinguish between account entries for the previously and newly regulated facilities, where applicable (e.g., Hydroelectric Water Conditions). OPG has been reporting sub-account balances to the OEB and will continue to do so.

Board Staff Interrogatory #194

Ref: Exh. H1-3-1 pages 1-15

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

For the proposal to make existing variance accounts applicable to the newly regulated hydroelectric facilities, please identify whether any accounts are required to be established under Ontario Regulation 312/13, and if so, provide the relevant section for each.

Response

Ontario Regulation 312/13 amended O. Reg. 53/05. This regulation is attached to Ex. L-1.0-2 AMPCO-002.

Ontario Regulation 312/13 places an additional 48 generation facilities (the newly regulated hydroelectric facilities) under OEB regulation as of July 1, 2014.

The amended O. Reg. 53/05 requires that the Capacity Refurbishment Variance Account apply to the newly regulated hydroelectric facilities as indicated in paragraph 4 of subsection 6(2) which says that the section applies to "a generation facility referred to in section 2." Section 2 includes the additional 48 generation facilities.

The OEB established the Capacity Refurbishment Variance Account in EB-2007-0905 pursuant to Section 6(2)4 of O. Reg. 53/05 as discussed in Ex H1-3-1, Page 8.

Board Staff Interrogatory #195

Ref: Exh. H1-3-1 pages 1-15

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please provide a historic variance analysis in table format consisting of years 2010, 2012 and 2013 for each of the proposed production-based deferral or variance accounts of the newly regulated hydroelectric facilities (i.e., not including the Income and Other Taxes Variance Account and the Pension & OPEBs Variance Account) as follows:

a) The production forecast (MWh) for each year determined by OPG's production forecast models (i.e., forecast prior to the start of the year)
b) The actual production (MWh) for each year (included in the consolidated audited financial statements)
c) The production variance (MWh) between a) and b) above for each year
d) The financial impact applying the variance (MWh) in c) above multiplied by the payment amount ($/MWh) for newly regulated hydroelectric facilities requested in this application.

Response

The following variance accounts proposed to be extended to the newly regulated hydroelectric facilities use production as an input: the Hydroelectric Water Conditions Variance Account, the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account, and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account. The requested historic analysis is not meaningful in relation to the first two of these accounts, as additions to these accounts are not determined on the basis of total variances between forecast and actual production, as explained below.

For the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the financial impact is determined on the basis of forecast-to-actual production variances. However, there would be no entries into the account until payment riders are established for recovery of variance and deferral account balances for the newly regulated hydroelectric facilities.

Hydroelectric Water Conditions Variance Account
This account records the financial impact (including changes in gross revenue charges ("GRC") costs) of differences between forecast and actual water conditions. As discussed in Ex. H1-3-1, section 3.1, the production impact of changes in water conditions is determined by entering the actual water flows into the forecast model, while holding constant all other variables used in determining the forecast. OPG has not historically performed these calculations for the newly

regulated facilities and is currently implementing a process to compute such variances effective July 1, 2014.

Hydroelectric Surplus Baseload Generation Variance Account

As described in Ex. H1-3-1, section 3.4, this account records the financial impact (including changes in GRC costs) of foregone production due to SBG conditions. Since the establishment of the variance account in 2011, OPG has developed a methodology for determining such foregone production at the previously regulated facilities (Ex. E1-2-1 section 3.0). OPG expects to extend this methodology to the newly regulated facilities. Therefore, calculations of foregone production due to SBG conditions at these facilities are not available for historic periods.

Notwithstanding the above, provided below in Chart 1, is the multiplication of the 2010 - 2013 annual production variances and the proposed newly regulated hydroelectric payment amount. As noted above, the full financial impact calculation of production variances would reflect partially offsetting impacts on GRC costs.

Chart 1

Numbers may not add due to rounding.

Line No.	Particulars	2010	2011	2012	2013
1	**Forecast Production (TWh)**[1, 2]	12.4	12.5	12.5	12.4
2	**Actual Production (TWh)**[1]	10.0	11.5	10.9	12.5
3	**Difference (TWh)** (line 2 - line 1)	(2.4)	(0.9)	(1.6)	0.0
4	**Production Difference at $47.59/MWh ($M)**	(113.7)	(44.8)	(76.1)	1.2

Notes

1 2010 to 2013 forecast production and 2010 to 2012 actual production is as reported in Ex. E1-1-2 Table 1. 2013 actual production is as reported in Ex. L-1.0-1 Staff 002, Table 13.

2 As noted at Ex. E1-1-1, p. 2, lines 18-21, the forecast production does not include any reductions for foregone production due to SBG conditions.

Board Staff Interrogatory #196

Ref: Exh. H1-3-1 pp 1-15

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

In the context of the IESO administered electricity spot market,

a) Please indicate the nature of the newly regulated hydroelectric facilities in terms of their name plate capacities and the conditions under which they generally operate in the electricity market (e.g., to serve base load, peak, etc.).
b) Will the newly regulated hydroelectric facilities continue to operate in the same manner in the electricity spot market notwithstanding they will have regulated prices?
c) Is there more or less incentive to produce and supply electricity for dispatching to the spot market given that the prices are regulated and no longer tied to spot market price?

Response

a) The net in-service capacities of the newly regulated hydroelectric facilities are shown in Ex. A1-4-2, Chart 2, pp. 3-4. The conditions under which these facilities generally operate are shown in Table 1 below. The conditions—or plant type—are divided into three categories:
   - Run of River Generating Station
     A "run-of-river" generating station typically has minimal forebay storage and passes some or all of the inflow through one or more turbines on a continuous basis, with the remainder (if any) going over an existing falls or spillway. Many of these facilities operate at both peak and off-peak hours.

   - Intermediate Generating StationAn "intermediate" generating station has "moderate" storage. These facilities have some ability to store water during off-peak hours in their forebays and/or in an upstream reservoir.

   - Peaking Generating StationA "peaking" generating station operates during periods of high energy demand, typically during the daytime on weekdays. These facilities have the ability to store water during off-peak hours in their forebays and/or in an upstream reservoir.

b) Yes, provided the enhanced Hydroelectric Incentive Mechanism ("eHIM") is approved by the OEB as it will incent OPG to continue to follow market price signals (Note: OPG interprets *"...to operate in the same manner..."* as continue to follow market price signals ("HOEP")).

c) Consistent with OPG's prefiled evidence, the inclusion of the newly regulated hydroelectric portfolio in the eHIM (Ex. E1-2-1) will ensure that the incentive to produce electricity will not change with price regulation.

Table 1

River System	Station	Type
Madawaska	Mountain Chute	Peaking
	Barrett Chute	Peaking
	Calabogie	Run-of-river
	Stewartville	Peaking
	Arnprior	Peaking
Ottawa	Otto Holden	Intermediate
	Des Joachims	Intermediate
	Chenaux	Intermediate
	Chats Falls	Run-of-river
Abitibi	Abitibi Canyon	Peaking
	Otter Rapids	Peaking
Montreal	Lower Notch	Peaking
Nipigon	Pine Portage	Run-of-river
	Cameron Falls	Run-of-river
	Alexander	Run-of-river
Aguasabon	Aguasabon	Run-of-river
Kamanistikwia	Silver Falls	Run-of-river
	Kakabeka Falls	Run-of-river
English	Manitou Falls	Run-of-river
	Caribou Falls	Run-of-river
Winnipeg	Whitedog Falls	Run-of-river
Montreal	Indian Chute	Run-of-river
Matabitchuan	Matabitchuan	Run-of-river
Mississippi	High Falls	Run-of-river
Rideau	Merrickville	Run-of-river
Otonabee	Lakefield	Run-of-river

	Auburn	Run-of-river
Trent	Seymour	Run-of-river
	Ranney Falls	Run-of-river
	Hagues Reach	Run-of-river
	Meyersburg	Run-of-river
	Sills Island	Run-of-river
	Frankford	Run-of-river
	Sidney	Run-of-river
Beaver	Eugenia Falls	Intermediate
Muskoka	Trethewey	Run-of-river
	Hanna Chute	Run-of-river
	South Falls	Run-of-river
	Ragged Rapids	Run-of-river
	Big Eddy	Run-of-river
Severn	Big Chute	Run-of-river
South	Elliot Chute	Run-of-river
	Bingham Chute	Run-of-river
	Nipissing	Run-of-river
Sturgeon	Crystal Falls	Run-of-river
Wanapitei	Stinson	Run-of-river
	Conistion	Run-of-river
	McVittie	Run-of-river

CCC Interrogatory #026

Ref:

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please explain whether the proposal to "regulate" the new hydroelectric facilities is better for Ontario ratepayers relative to a proposal that keeps those assets unregulated. If it is not better for Ontario ratepayers why is the proposal justified?

Response

The decision to regulate more of OPG's hydroelectric facilities was made by the Government of Ontario.

The amended O. Reg. 53/05 was finalized and issued in November 2013. The amendment prescribes an additional 48 hydroelectric facilities for regulation by the OEB, effective July 1, 2014. The finalized version of O. Reg. 53/05 has been included as Attachment 1 to Ex. L-01.0-2 AMPCO-002. OPG's application is consistent with the amended O. Reg. 53/05.

SEC Interrogatory #136

Ref: H1-3-1/p.2

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please describe how the variability of water conditions in each of the newly regulated hydroelectric facilities compares to the variability of water conditions on the Niagara and St. Lawrence Rivers.

Response

All watersheds are subject to constantly changing conditions that can result in increases or decreases in flow. As the Niagara and St. Lawrence Rivers are a part of the very large Great Lakes - St. Lawrence River watershed, flow is impacted by both the total basin supply (inflow from upstream) and net basin supply (local changes). Changes seen in the upper Great Lakes can take approximately two years to impact the lower Great Lakes and St. Lawrence River, while local changes (e.g. storms travelling up the Ohio River to Lake Erie) have a much more immediate impact at Niagara and the St. Lawrence. However, the magnitude of the flow in the Great Lakes system also generally helps to reduce the impact of local storms or freshet (spring runoff).

All of the rivers on which the newly regulated facilities are located are affected by local conditions to a much greater degree. Historical median monthly flows are used in the forecasts for these rivers because it is not possible to accurately predict what the weather and water conditions will be over the longer term. Watersheds containing the newly regulated facilities are more reactive to storms and freshet conditions, with the response also being much quicker. It is possible to go from very low conditions to very high flow conditions over a freshet period or due to a strong storm system.

SEC Interrogatory #137

Ref: H1-3-1/p.4

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please provide details of past Ancillary Services Revenues from the newly regulated hydroelectric facilities, and compare those revenues to the revenues from the previously regulated hydroelectric facilities.

Response

Ancillary Service ($M)	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Niagara Plant Group and Saunders GS (Previously Regulated):	26.2	22.2	20.8	37.1
Newly Regulated Hydroelectric	26.4	26.1	25.9	35.7

SEC Interrogatory #138

Ref: H1-3-1/p.7

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please provide details of past CCA taken on the newly regulated hydroelectric facilities, and for each such facility compare the CCA to date with the depreciation to date. Please calculate the future tax liability associated with the timing differences.

Response

As noted in Ex. L-6.13-1 Staff-171, O. Reg. 53/05 requires the OEB to accept the values for the assets and liabilities of the newly regulated hydroelectric facilities as set out in OPG's 2013 audited financial statements. This requirement includes income tax effects of timing differences reflected in the above noted financial statements. As the values of the fixed and intangible assets ("PP&E") of the newly regulated hydroelectric facilities and the impact of the associated timing differences with respect to the Undepreciated Capital Cost ("UCC") of these assets are reflected in OPG's 2013 audited financial statements, the OEB must accept these values.

Timing differences are measured by comparing accounting and tax values of assets and liabilities. Therefore, the PP&E net book value and the UCC are required to satisfy the O. Reg. 53/05 requirement. These balances as at December 31, 2013 for the newly regulated hydroelectric facilities are provided in Ex. L-2.1-6 ED-003 b). Below is their breakdown by plant group, as well as the associated future income tax liability:

Newly Regulated Hydroelectric Net Book Value and Undepreciated Capital Cost
As at December 31, 2013

$M	**Net Book Value of PP&E**[1]	**Undepreciated Capital Cost**	**Future Income Tax Liability @ 25%**
Ottawa-St. Lawrence Plant Group	1,233.8	710.0	131.0
Central Hydro Plant Group	100.7	40.9	15.0
Northeast Plant Group	560.2	294.3	66.5
Northwest Plant Group	630.2	345.7	71.1
Total Newly Regulated Hydroelectric	**2,524.9**	**1,390.9**	**283.5**

[1]Caclulated as the difference between Ex. L-0-1 Staff-2, Att.1, Table 2, col. (e) and Table 3, col. (d)

SEC Interrogatory #139

Ref: H1-3-1/p.7

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

Please confirm that the Applicant is proposing to cause the ratepayers to be at risk for tax reassessments relating to the newly regulated hydroelectric facilities, for periods prior to the regulation of those facilities.

Response

Not confirmed. OPG is not seeking to recover the impact on periods prior to 2014 of tax reassessments.

As stated at Ex. H1-3-1, page 7, lines 19 - 20, OPG seeks the extension of the Income and Other Taxes Variance Account to the newly regulated hydroelectric facilities in order "to record the financial impact on the ***approved revenue requirement*** of" the factors listed at Ex. H1-3-1, section 3.5, including reassessments [emphasis added]. Therefore, if OPG's proposal is accepted, then tax reassessments that impact periods after July 1, 2014 would be candidates for inclusion in the variance account.

Board Staff Interrogatory #197

Ref: Exh H1-3-1 page 5 and Exh E1-2-1

Issue Number: 9.8
Issue: Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

Interrogatory

OPG is proposing a change to the operation of the HIM that eliminates the need for additions to the account in the future. However, please provide the reasons why this account should not continue with appropriate modifications, if applicable, in order to test the results of the proposed mechanism discussed in Exh E1-2-1 until the next payment order proceeding?

Response

There is no need for the existing Hydroelectric Incentive Mechanism Variance Account, or a modified version of this account, to continue because ratepayers will receive their share of the actual incentive payments each month through the operation of the IESO settlement process as explained in Ex. E1-2-1, pp. 12-14. Because of this approach, there is no variance that requires reconciliation through such an account.