ONTARIO POWER GENERATION

Garry M. Hendel
Director (Acting)

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-6054 Fax: 416-592-8519
garry.hendel@opg.com

February 8, 2013

RESS and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0002 – Evidence Update for 2012 Audited Actual Deferral and Variance Account Balances

Please find attached updates to evidence to incorporate audited actual December 31, 2012 balances in OPG's deferral and variance accounts. This package includes:

- A new Exhibit H1-1-2, which contains tables setting out and supporting audited actual December 31, 2012 account balances, as well as the associated rider and impact calculations. This exhibit describes reasons for differences between actual balances and projected balances originally filed where those differences are material. This exhibit also contains, as attachments, other supporting material such as auditors' and independent actuary's reports, and addresses certain update requests raised at the Technical Conference.

- Updated administrative documents, updated as required to give effect to proposed riders resulting from audited actual December 31, 2012 account balances.

- Updates to certain interrogatory responses to reflect actual results for 2012, including those as indicated in the original responses or later agreed to during the Technical Conference.

- Several corrections to pre-filed evidence and interrogatory responses.

A list of the amended evidence is provided below:

Exhibit	**Description**
A1-1-1	Updated page 2
A1-1-2	Updated page 2
A2-1-1	Updated pages 1 and 2
A2-1-2	Updated pages 1and 2
A3-1-2	Corrected pages 7 and 8
H1-1-1	Corrected Tables 4 and 6
H1-1-2	A new evidence schedule that provides audited actual December 31, 2012 account balances, the resulting riders and estimated impacts, and updated pension and OPEB projections for 2013
H1-2-1	Corrected page 1
H2-1-1	Corrected Tables 1 and 2
H2-1-3	Corrected page 1
L-1-1 STAFF-03	Updated page 2 to reflect actual 2012 results
L-1-1 STAFF-14	Corrected page 2
L-1-7 SEC-04	Updated page 1 and Table 1 to reflect actual 2012 results
L-1-7 SEC-17	Updated pages 1, 2 and 3 to reflect actual 2012 results
L-1-7 SEC-23	Updated Tables 1 and 1a to reflect actual 2012 results
L-2-2 AMPCO-04	Corrected page 2
L-3-1 STAFF-27	Updated page 2, Table 1 to reflect actual 2012 results and corrected page 2, Table to Note 4
L-3-2 AMPCO-13	Updated page 1 and Tables 1, 2 and 3 to reflect actual 2012 results
L-3-2 AMPCO-14	Updated page 1 and Tables 1 and 2 to reflect actual 2012 results
L-3-2 AMPCO-16	Updated Table 1 to reflect actual 2012 results
L-3-3 CME-01	Updated page 2 to reflect actual 2012 results and added attachment
L-6-1 STAFF-32	Corrected page 1

Respectfully submitted,

[Original signed by]

Garry M. Hendel
Director (Acting), Ontario Regulatory Affairs
Ontario Power Generation

Attach:

cc: Charles Keizer Torys LLP
Carlton Mathias OPG
EB-2012-2002 Intervenors

EXHIBIT LIST			
EX	TAB	SCH	CONTENTS
A			ADMINISTRATIVE DOCUMENTS
A1	1	1	Exhibit List
	1	2	Application
A2	1	1	Summary of Application
		2	Approvals
A3	1	1	Financial Summary Attachment 1: OPG's 2011 Annual Report Attachment 2: 2011 Audited Annual Consolidated Financial Statements for the Prescribed Facilities
A3	1	2	Approval to Use Generally Accepted Accounting Principles of the United States Attachment 1: Financial Administration Act, O. Reg. 395/11 Attachment 2: OSC's Decision on OPG's application for an exemption to prepare financial statements in accordance with USGAAP Attachment 3: Aon Hewitt's "Transition Report for US GAAP from Canadian GAAP for Pension, Non-Pension Post Retirement, and Post-Employment Benefit Plans" for Ontario Power Generation Inc.
A4	1	1	Stakeholder Information Session Attachment 1: August 29, 2012, Stakeholder Information Session Agenda Attachment 2: Stakeholder Invitation Letter, Funding Guidelines, and List of Invited Participants
		2	Procedural Orders / Correspondence / Notices
		3	List of Witnesses
		4	Curricula Vitae of Witnesses
		5	Draft Issues List
H			DEFERRAL AND VARIANCE ACCOUNTS
H1			Deferral and Variance Account Overview, Clearance and Continuation

H2	2	1	Supporting Evidence for Entries into Nuclear Accounts Attachment 1: Minister's Letter from Brad Duguid, Minister of Energy to Honourable Jake Epp, OPG dated March 8, 2011 Re: Long Term Energy Plan as it relates to OPG
I			DETERMINATION OF RIDERS
I1	1	1	Regulated Hydroelectric and Nuclear Riders
		2	Rate and Consumer Impact

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving the disposition of the balances as of December 31, 2012 in its deferral and variance accounts and approving the adoption of USGAAP for regulatory purposes.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the Ontario *Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.

2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders approving the disposition of the balances as of December 31, 2012 in its deferral and variance accounts, except for the balances in the Hydroelectric Incentive Mechanism Variance Account and Hydroelectric Surplus Baseload Generation Variance Account, and the hydroelectric portion of the Capacity Refurbishment Variance Account. To clear the account balances, OPG seeks separate payment riders for the nuclear and regulated hydroelectric accounts for the generating facilities prescribed under Ontario Regulation 53/05 ("O. Reg. 53/05"), as amended, of the Act.

3. OPG proposes that for accounts other than the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, clearance of the account balances would occur over a two-year period from January 1, 2013 through December 31, 2014. For the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, OPG proposes account balance clearance over a four-year period from January 1, 2013 through December 31, 2016.

4. OPG is seeking an order continuing the authorization to post entries into the Pension and OPEB Cost Variance Account beyond the current expiration date of December 31, 2012 set by the OEB. OPG proposes that this authorization continue until the effective date of the next OEB order establishing new payment amounts. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting entries into this account pending the OEB's decision.

5. OPG seeks an order from the OEB approving the adoption of Generally Accepted Accounting Principles of the United States of America ("USGAAP") for regulatory purposes.

6. OPG seeks an order of the OEB continuing the current payment rider for the prescribed nuclear facilities beyond December 31, 2012, if an order approving a new nuclear payment rider is not implemented by January 1, 2013. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks a declaration that the current nuclear payment rider is interim as of January 1, 2013.

7. To achieve the requested disposition of the balances in the deferral and variance accounts (as described in paragraph 2 above), OPG is seeking payment riders covering both 2013 and 2014 of $2.60/MWh and $8.34/MWh for Hydroelectric and Nuclear, respectively. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks interim period shortfall riders with an expiry date of December 31, 2014.

8. The Application will be supported by written evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

9. OPG requests that pursuant to section 34.01 of the OEB Rules of Practice and Procedure, this proceeding be conducted by way of a written hearing.

10. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

11. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

12. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 24 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

(a)	The applicant:	Colin Anderson Director, Ontario Regulatory Affairs Ontario Power Generation Inc.
	Mailing address:	H18 G2 700 University Avenue Toronto ON M5G 1X6
	Telephone:	416-592-3326
	Facsimile:	416-592-8519
	Electronic mail:	opgregaffairs@opg.com
(b)	The applicant's Counsel:	Charles Keizer Torys LLP

Mailing address: 79 Wellington St. W.
PO Box 270
Toronto Dominion Centre
Toronto ON M5K 1N2

Telephone: 416-865-0040

Facsimile: 416-865-7380

Electronic mail: ckeizer@torys.com

(c) The applicant's Counsel: Carlton D. Mathias
Assistant General Counsel
Ontario Power Generation Inc.

Mailing address: H18 A24
700 University Avenue
Toronto ON M5G 1X6

Telephone: 416-592-4964

Facsimile: 416-592-1466

Electronic mail: carlton.mathias@opg.com

Dated at Toronto, Ontario, this 24th day of September, 2012.

Ontario Power Generation Inc.

[Original signed by]

____

Charles Keizer
Torys LLP

SUMMARY OF APPLICATION

This is an application to the Ontario Energy Board for:

- Clearance of certain deferral and variance account balances as of December 31, 2012 through the establishment of nuclear and hydroelectric payment riders;
- Continuation of the Pension and OPEB Cost Variance Account; and
- Adoption of Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory purposes.

What is this Proceeding About?

This proceeding has been initiated to clear all of OPG's deferral and variance account balances except for those in the Hydroelectric Incentive Mechanism ("HIM") Variance Account, Hydroelectric Surplus Baseload Generation ("SBG") Variance Account and hydroelectric portion of the Capacity Refurbishment Variance Account. OPG's reasons for deferring clearance of these three accounts are explained below. For the accounts that OPG seeks to clear, OPG's pre-filed evidence filed September 24, 2012, presented projected 2012 year-end balances. On February 8, 2013 OPG filed audited December 31, 2012 balances for these accounts, which OPG proposes form the bases of the ordered riders.

OPG is proposing to defer clearance of the HIM account, the SBG account, and the hydroelectric portion of the Capacity Refurbishment Variance Account until the next payment amounts proceeding. OPG believes that clearance of these balances should be deferred because the studies that the OEB ordered in relation to the HIM and SBG accounts remain underway. Review of the accounts can also be more efficiently and comprehensively addressed in the context of the overall Hydroelectric evidence in the next payment amounts application. The 2012 balance of the hydroelectric portion of the Capacity Refurbishment Variance Account relates mostly to the Niagara Tunnel Project ("NTP") and can be most effectively reviewed in a proceeding that addresses NTP costs. Finally, the balances in these accounts are relatively small. Exhibit. H1-1-1 provides additional discussion of the decision to defer recovery of the balances in these accounts.

OPG's application also addresses extending the authority to post entries into the Pension and OPEB Cost Variance Account. This is more fully discussed in Ex. H2-1-3. OPG seeks to extend the duration of this account until the effective date of the next payment amounts order.

Finally, this application also contains OPG's request for approval to adopt USGAAP for regulatory purposes and, if approval is granted, to clear the balances in the Impact for USGAAP Deferral Account as of December 31, 2012.[1]

What Are the Requested Payment Riders?

OPG requests that recovery of the approved balances for all deferral and variance accounts for which clearance is sought occur over two years (January 1, 2013 through December 31, 2014), except for the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account. Given the size of the balances anticipated in these two accounts, OPG proposes to clear them over four years (January 1, 2013 through December 31, 2016). The Hydroelectric and Nuclear riders for both 2013 and 2014 based on audited actual 2012 year-end balances are $2.60/MWh and $8.34/MWh, respectively. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks interim period shortfall riders with an expiry date of December 31, 2014.

What is OPG's Proposal for the Pension and OPEB Cost Variance Account?

OPG proposes that the balance in this account as of December 31, 2012 be cleared as described above. OPG is also requesting authorization to continue posting entries into the account until the effective date of the OEB's next payment amounts order for OPG. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting entries into this account pending the OEB's decision.

The Pension and OPEB Cost Variance Account has an end-date of December 31, 2012.

[1] The OEB has stated that if approval to adopt USGAAP for regulatory purposes is not granted, then amounts in the Impact for USGAAP Deferral Account are not recoverable (EB-2011-0432, Decision with Reasons, page 7).

Given that this account was established by the OEB in EB 2011-0090 as the best remedy to correct an error in OPG's payment amounts decision (EB-2010-0008), if the December 31, 2012 end-date is not extended, subsequent payment amounts will be based on an erroneous pension and OPEB cost estimate without a mechanism to correct that error. This would appear to frustrate the original intent of the OEB in establishing the variance account, i.e., correction of an error in setting payment amounts in EB-2010-0008.

OPG is requesting the authority to continue posting entries into the account to provide the OEB with a mechanism to consider the appropriate level of pension and OPEB costs in a future proceeding based upon the OEB's decision in EB-2011-0090. OPG acknowledges that extending this account does not provide any guarantee that the amounts recorded after December 31, 2012 will be subsequently approved for recovery by OPG.

What Is OPG's Proposal Regarding USGAAP?

OPG is seeking approval to adopt USGAAP for regulatory purposes. OPG has already been legislated to move to USGAAP for accounting and financial reporting purposes. To avoid the cost and effort of maintaining two different sets of accounting records, to increase the comparability between financial and regulatory reporting and to remove the ongoing uncertainty over this issue for OPG and ratepayers, OPG is requesting that the OEB decide this issue now, rather than waiting until the next payment amounts application.

OPG requests that the OEB approve both the use of USGAAP for regulatory purposes and the clearance of the balances in the Impact for USGAAP Deferral Account as of December 31, 2012. OPG proposes that the account be cleared over two years (i.e., January 1, 2013 to December 31, 2014).

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- Approval to clear the approved balances in the following accounts as of December 31, 2012:
  - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
  - Income and Other Taxes Variance Account
  - Tax Loss Variance Account
  - Pension and OPEB Cost Variance Account
  - Impact for USGAAP Deferral Account
  - Hydroelectric Water Conditions Variance Account
  - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account[1]
  - Nuclear Liability Deferral Account
  - Nuclear Development Variance Account
  - Capacity Refurbishment Variance Account for Nuclear prescribed facilities[2]
  - Bruce Lease Net Revenues Variance Account
  - Nuclear Deferral and Variance Over/Under Recovery Variance Account[3]
- Approval to clear the approved balances in the above referenced accounts, except the Pension and OPEB Cost Variance Account and the Bruce Lease Variance Account, over two years (January 1, 2013 through December 31, 2014).
- Approval to clear the approved balances in the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account over four years (January 1, 2013 through December 31, 2016).

[1] In accordance with the EB-2010-0008 Payment Amounts Order, the balance in the account as at December 31, 2012 includes the remaining balance in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account, which was terminated on December 31, 2012. As such the Hydroelectric Interim Period Shortfall (Rider D) Variance Account is not included in the list of the requested approvals.
[2] OPG is not proposing to clear the entries in this account related to Hydroelectric prescribed facilities because these entries are relatively small and are primarily attributable to the Niagara Tunnel Project.
[3] In accordance with the EB-2010-0008 Payment Amounts Order, the balance in the account as at December 31, 2012 includes the remaining balance in the Pickering A Return To Service Deferral Account, which was terminated on December 31, 2011, and the remaining balances in the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account, and the Nuclear Interim Period Shortfall (Rider B) Variance Account, which were terminated on December 31, 2012. As such, these terminated accounts are not included in the list of the requested approvals.

- Approval to continue posting entries into the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order.
- Approval to adopt for regulatory purposes the Generally Accepted Accounting Principles of the United States.
- Approval of the following payment riders for both 2013 and 2014: Hydroelectric $2.60/MWh and Nuclear $8.34/MWh.

In this Application, OPG also is seeking the following interim approvals:

- An order from the OEB to continue OPG's current nuclear payment rider on an interim basis as of January 1, 2013, since the OEB's order will be based on audited account balances that will not be available until February 2013. OPG is proposing that the current hydroelectric rider be allowed to expire because it is negative and, thus, its continuation would only increase the shortfall to be recovered.
- An order from the OEB approving interim period shortfall riders, since the OEB's order will be based on audited account balances that will not be available until February 2013. These interim period shortfall riders would expire on December 31, 2014.
- An order from the OEB authorizing OPG to continue posting entries into the Pension and OPEB Cost Variance Account on an interim basis after December 31, 2012 until a decision is issued on OPG's request to extend the duration of this account. This order is necessary only if OPG's request to extend the account is not decided by December 31, 2012.

Approval to Use Generally Accepted Accounting Principles of the United States

1.0 PURPOSE

OPG is seeking approval to use the Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting, reporting and rate-making purposes. This evidence identifies differences between USGAAP and Canadian Generally Accepted Accounting Principles ("CGAAP") that affect OPG's regulatory accounting and describes the financial impacts on OPG's prescribed assets resulting from the transition from CGAAP to USGAAP recorded in the Impact for USGAAP Deferral Account. The account is discussed in Ex. H1-1-1 and summarized in Ex. H1-1-1, Table 6. The evidence also addresses the benefits that OPG sees from adopting USGAAP for regulatory purposes.

2.0 OVERVIEW

OPG is proposing to adopt USGAAP for regulatory purposes effective January 1, 2012. OPG has completed its analysis of the impacts resulting from adopting USGAAP and determined that the transition to and implementation of USGAAP would affect OPG's regulatory accounting in three areas: long term disability benefit plan ("LTD") costs, which are part of pension and other post employment benefits ("OPEB"), Scientific Research and Experimental Development ("SR&ED") investment tax credits ("ITCs") and Bruce Lease revenues and costs. The only change that has a financial impact on OPG's prescribed assets is the change in the treatment of actuarial losses and gains and past service costs associated with OPG's LTD plan and related income tax impacts. Owing solely to this LTD impact, OPG is forecasting an addition of $58.5M in the Impact for USGAAP Deferral Account in 2012.

The evidence identifies the benefits of adopting USGAAP as opposed to International Financial Reporting Standards ("IFRS") in Section 5.0. In summary, the benefits of adopting USGAAP rather than IFRS are:

- fewer and significantly smaller financial impacts;
- more stable financial results resulting in greater rate stability;

- reduced costs of record-keeping and regulatory review; and
- financial information that better represents OPG's underlying financial circumstances.

OPG is requesting approval to adopt USGAAP for regulatory purposes at this time to avoid keeping multiple sets of financial records. OPG must maintain CGAAP financial records for regulatory reporting purposes until its payment amounts are reset to ensure that information is reported on the same basis upon which the current payment amounts were established. OPG would also have to maintain its financial records on both a USGAAP and IFRS basis to enable it to meet its regulatory reporting obligations to the OEB until such time as the OEB approves a new regulatory accounting approach for OPG.

OPG has incurred costs associated with the implementation of USGAAP for financial accounting purposes, but OPG is not seeking recovery of these costs.

3.0 BACKGROUND

Effective January 1, 2012, OPG is required to prepare its consolidated financial statements in accordance with USGAAP pursuant to O. Reg. 395/11 under the *Financial Administration Act* (Ontario), which can be found in Attachment 1. OPG had also applied for and received an exemption from the Ontario Securities Commission ("OSC") to file its consolidated financial statements based on USGAAP rather than IFRS, which is provided in Attachment 2. The exemption applies to the financial years that begin on or after January 1, 2012, but before January 1, 2015. The exemption is similar to those received by Hydro One, Union Gas, Enbridge and other utilities regulated by the OEB that have received or are seeking approval to use USGAAP for regulatory purposes.

OPG's current payment amounts were established in the EB-2010-0008 Payment Amounts Order using CGAAP as the basis for regulatory accounting, reporting and rate-making. The Impact for USGAAP Deferral Account approved by the OEB in the EB-2011-0432 Decision and Order issued on March 2, 2012 captures the transition and implementation impacts of differences between CGAAP and USGAAP on OPG's prescribed assets from January 1, 2012 to the effective date of the next payment amounts order. The disposition of the projected balance as at December 31, 2012 in the Impact for USGAAP Deferral Account is discussed in Ex. H1-2-1.

As part of the adoption of USGAAP on January 1, 2012, OPG was required to restate its 2011 comparative financial information on a USGAAP basis and to prepare a USGAAP opening balance sheet as at January 1, 2011 (the “2012 Restatement”). This USGAAP balance sheet must be used as the reference point for determining the financial impacts from the adoption of USGAAP. This revised financial information also forms the starting point for USGAAP reporting in OPG’s 2012 financial statements.

4.0 ACCOUNTING DIFFERENCES BETWEEN CGAAP AND USGAAP

OPG has identified differences between CGAAP and USGAAP that would impact its regulatory accounting in three distinct areas: LTD costs, SR&ED ITCs and base rent revenue under the Bruce Lease. As noted above, only the change related to LTD costs has resulted in entries into the Impact for USGAAP Deferral Account.

4.1 Long-Term Disability Plan Costs Included in the Impact for USGAAP Deferral Account

The total projected impact on LTD costs through 2012 from adopting USGAAP is $58.5M. The projected December 31, 2012 balance in the Impact for USGAAP Deferral Account to be recovered by OPG is $59.3M, which includes the projected LTD impact plus an estimated $0.8M in interest. This projected LTD impact has three components: transition costs, implementation costs and related tax impacts. The amounts associated with each component are presented in Chart 1 and discussed below. The details underlying Chart 1 can be found in Ex. H1-1-1, Table 6.

Chart 1

	LTD Costs	
Line	**Cost Component**	**Amount ($M)**
	Transition Costs:	
1	LTD costs recognized on the opening USGAAP balance sheet arising from the 2012 Restatement	31.4
2	Differences in CGAAP and USGAAP costs for 2011 arising from the 2012 Restatement (actual)	9.3
3	Total Transition Costs (lines 1 + 2)	40.7
4	Implementation Costs: projected differences in CGAAP and USGAAP costs for 2012	3.2
5	Tax Impact	14.6
	TOTAL (lines 3 + 4 + 5)	58.5

Transition Costs: OPG adopted USGAAP on January 1, 2012. Transition costs were incurred at that time, and are reflected in the 2012 Restatement both as an adjustment to the 2011 opening balance sheet and through differences in 2011 costs.

As described in EB-2011-0432, under USGAAP all actuarial gains and losses and past service costs related to the LTD plan must be recognized immediately on the statement of income. In contrast, under CGAAP, the net cumulative unamortized actuarial gain or loss for the LTD plan in excess of ten per cent of the benefit obligation was amortized over the expected average remaining service life of the employees. In addition, past service costs related to the LTD plan were recognized over the expected average remaining service period of the affected employee groups.

This difference in accounting requirements gives rise to the transition costs. Specifically, OPG was required under USGAAP to recognize $31.4M of previously unamortized net actuarial losses and past service costs for the prescribed assets related to the LTD plan ($30.0M for nuclear and $1.4M for regulated hydroelectric). Through the 2012 Restatement, this amount was determined using the required starting point for reporting under USGAAP as of January 1, 2011. Under CGAAP, these amounts would have been included in the calculation of OPEB costs that would have been part of the revenue requirements in future payment amounts applications. Therefore, OPG has recorded $31.4M in the Impact for USGAAP Deferral Account in Ex H1-1-1, Table 6, line 1.[1]

Also arising from the 2012 Restatement is the difference in the accounting treatment for LTD costs under USGAAP, which produced higher restated costs for 2011. Under CGAAP these amounts would have been included in the calculation of OPEB costs that would have been part of the revenue requirements in future payment amounts applications. Therefore, OPG has recorded $9.3M in the Impact for USGAAP Deferral Account in Ex H1-1-1, Table 6, line 4.

Implementation Costs: The difference in the accounting treatment for LTD costs required as a result of the adoption of USGAAP is projected to produce higher costs during 2012. The difference in costs will continue until payment amounts are reset as part of the next payment amounts order. Variances are recorded in the Impact for USGAAP Deferral Account as incurred. As shown in Ex H1-1-1, Table 6, line 7, $3.2M is the projected variance for 2012.

Tax Impacts: The increased LTD costs recorded under USGAAP give rise to income taxes because they are not deductible for tax purposes while their recovery results in taxes payable by OPG. These taxes are a direct result of adopting USGAAP. As such, they are recorded in the Impact for USGAAP Deferral Account. This approach follows that used by OPG in assigning costs to the Pension and OPEB Cost Variance Account, which was approved in EB-2011-0090 as discussed in Ex. H2-1-3. As of December 31, 2012, OPG is projecting an amount of $14.6M for tax impacts as shown in Ex. H1-1-1, Table 6, line 8. As with implementation cost differences, tax impacts will also continue until payment amounts are reset as part of the next payment amounts order.

4.2 Other Accounting Impacts of Adopting USGAAP

[1] The $31.4M represents the regulated portion of the total OPG-wide amount of $39.6M, which is provided at pages 3 and 8 of the independent actuarial report on the impact of OPG’s transition to US GAAP on its pension and OPEB costs by OPG’s actuary, Aon Hewitt, in Attachment 3 to this exhibit.

Adopting USGAAP for regulatory accounting purposes would also produce impacts in the following two areas. These matters do not require any entries in the Impact for USGAAP Deferral Account.

4.2.1 Scientific Research and Experimental Development Investment Tax Credits

As described in EB-2010-0008, the amount of SR&ED ITCs recognized for accounting purposes and reflected in the revenue requirement is determined based on an assessment of the likelihood of their allowance. The amount of ITCs recognized is the same under USGAAP and CGAAP, but the presentation of ITCs changes from a reduction to OM&A expenses to a reduction to the income tax expense. As the change solely involves presentation, there is no financial impact associated with this USGAAP requirement.

4.2.2 Bruce Lease Base Rent Revenue

USGAAP requires the amount of base rent revenue to be recognized on a straight-line basis from the start of the Bruce Lease in 2001. Under CGAAP, the amount of rent revenue recognized is calculated on a straight-line basis effective April 1, 2008 following the OEB's direction that "Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses" (EB-2007-0905, page 110). The earlier effective date for the purposes of the straight-line calculation under USGAAP results in a lower amount of revenue being recognized over the remaining expected lease term.

The consequent reduction in base rent revenue of $2.2M per year starting in 2011 results in a corresponding reduction in deferred taxes of $0.6M, so the overall impact is a $1.6M annual reduction in Bruce Lease net revenues. This change will increase the revenue requirement in OPG's next application for new nuclear payment amounts based on USGAAP, but has no impact on the deferral and variance account balances.

5.0 THE OEB CRITERIA FOR AUTHORIZING UTILITIES TO ADOPT USGAAP FOR REGULATORY PURPOSES

In the EB-2008-0408 Addendum Report, the OEB stated that a utility seeking to adopt USGAAP must:

- demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
- include a copy of the authorization to use USGAAP from the appropriate Canadian securities regulatory body (if applicable); and
- set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

As discussed above in Section 3.0, OPG must adopt USGAAP for financial accounting purposes effective January 1, 2012 and has received authorization to do so (Attachment 2). Adopting USGAAP for regulatory purposes has a number of benefits compared to the alternative of adopting IFRS.[2] These are:

1) *Fewer and significantly smaller financial impacts:* The financial impacts associated with OPG's adoption of USGAAP are discussed in Section 4, which shows a total projected after-tax impact on the prescribed assets of approximately $58.5M at the end of 2012. The impacts associated with adopting IFRS would be substantially larger and require more adjustments to CGAAP.

   The single largest impact for the prescribed assets would result from differences between CGAAP and IFRS related to the treatment of actuarial gains and losses and past service costs associated with all of OPG's pension and OPEB plans, including the LTD plan, upon the mandatory adoption by OPG of International Accounting Standard 19, *Employee Benefits* ("IAS 19"), as amended, no later than January 1, 2013.

   In accordance with IFRS requirements, to effect a January 1, 2013 adoption date, OPG would be required to calculate the changes due to IAS 19 as of January 1, 2012. The resulting impact would be to recognize, as a component of equity, all previously unamortized actuarial gains and losses and past service costs calculated as of January 1, 2012. Using January 1, 2012 as the starting point for reporting under IAS 19 also would create additional impacts for 2012 based on the actuarial gains and losses

[2] OPG is not aware of any disadvantages associated with adopting USGAAP for regulatory purposes relative to adopting IFRS.

arising during that year, which would be charged to and remain in accumulated other comprehensive income ("AOCI"). As at the end of 2012, OPG projects the cumulative impact of the changes above to be close to $3.9 billion on a pre-tax basis.[3]

Under USGAAP, while all actuarial gains and losses and past service costs for non-LTD plans are charged to AOCI, they are transferred from AOCI to pension and OPEB costs on the statement of income over time in a manner consistent with CGAAP (i.e., subject to the corridor approach and over the expected remaining service life of the employees). Therefore, under USGAAP, these amounts would continue to be deferred and amortized into revenue requirements as part of future payment amounts applications as currently occurs under CGAAP.

Under IFRS, OPG would be required to seek OEB approval to establish one or more deferral accounts in an attempt to moderate the impacts identified above. Even with these deferral accounts however, unless the resulting balances were amortized over periods substantially longer than those which have been authorized to date for OPG, ratepayers would still experience significant impacts under IFRS. For this reason alone, in OPG's case, the adoption of USGAAP clearly would benefit ratepayers compared to IFRS.

Adoption of IFRS would also significantly impact the accounting treatment of OPG's nuclear decommissioning and nuclear waste management liabilities ("nuclear liabilities") and related costs, including differences that would arise upon accounting recognition of changes in the nuclear liabilities arising from a new approved Ontario Nuclear Funds Agreement Reference Plan. These differences would include a change in the timing of recognition of certain waste management costs due to their re-categorization from fixed costs under CGAAP to variable costs under IFRS. Fixed costs

[3] In its application in EB-2011-0432 (p. 5, lines 27-29), OPG cited an equivalent estimated pre-tax impact of in excess of $2 billion. The estimate cited in this exhibit has been updated to reflect the actual financial results for 2011 and the projected results for 2012.

are capitalized and expensed over time while variable costs are expensed immediately resulting in greater customer impacts.

Adoption of IFRS also would require OPG to apply a current accretion rate to the full amount of the liabilities. In contrast, under CGAAP, a current accretion rate is established for each new tranche as it is added. Thus when the amount of liabilities increases, it is only the latest tranche, not the entire liability, that receives the current accretion rate under CGAAP. This results in less volatility. To address these differences in the treatment of nuclear liabilities under IFRS, OPG would have had to seek OEB approval to establish additional regulatory deferral accounts consistent with the principles cited in the EB-2008-0408 Report of the Board.

2) *More stable financial results, which promote greater rate stability:* As it applies to OPG, USGAAP is substantially similar to CGAAP in most areas. In contrast, the changes under IFRS discussed above for nuclear liabilities and pension and OPEB plans would introduce additional volatility. Under USGAAP, OPG would be able to continue capitalizing certain costs related to nuclear liabilities and continue recognizing pension and OPEB costs in the income statement over time. Both of these differences significantly reduce the volatility that would be introduced into OPG's reported financial results by the adoption of IFRS. This additional volatility would be attributable both to the initial impact of adopting IFRS and to the subsequent impacts of periodic changes in nuclear liabilities and annual changes in pension and OPEB costs. By reducing the volatility of OPG's costs, USGAAP also would result in more stable payment amounts and avoid the need for moderating deferral accounts with extremely long amortization periods.

3) *Reduction in the costs of record-keeping and greater comparability:* As OPG has adopted USGAAP for financial reporting, the adoption of USGAAP for regulatory purposes would allow OPG to maintain a single accounting system once new USGAAP-based payment amounts are established. This would allow OPG to avoid the associated costs of maintaining accounting records on two different bases going

forward. Having a single system also would provide greater comparability between the financial information used in setting OPG's payment amounts and OPG's audited financial accounting data.

4) *Financial information that better represents OPG's underlying financial circumstances:* USGAAP provides a well recognized, accepted and comprehensive basis of accounting that better reflects the economic substance of the impact of rate regulation on OPG's financial results through continued recognition of regulatory assets and liabilities in the same manner as CGAAP. In contrast, the adoption of IFRS would distort OPG's financial results because under the current formulation of IFRS, OPG would be unable to recognize certain regulatory assets and liabilities.[4] As discussed above, adopting USGAAP also results in significantly less income volatility than IFRS. For these reasons, adopting USGAAP would benefit the OEB and participants in the regulatory process, as well as other users of OPG's financial statements.

The OEB has approved the use of USGAAP for most of the larger utilities it regulates including Union Gas, Hydro One Transmission and Hydro One Distribution.[5] These utilities based their requests for authority to adopt USGAAP for regulatory purposes on reasons similar to those advanced above and the OEB largely accepted these reasons in granting their requests.[6]

In approving Hydro One Transmission's adoption of USGAAP for regulatory purposes, the OEB observed that: "Moving to USGAAP may offer advantages in enabling more meaningful benchmarking possibilities."[7] As most of the companies used in OPG's financial benchmarking are located in the United States, this observation would apply equally to OPG.

[4] Considerable uncertainty exists regarding the outcome and timing of future changes to IFRS, if any, with respect to accounting for regulatory assets and liabilities.
[5] Moreover, the OEB is not alone in allowing regulated utilities to adopt USGAAP. A number of other Canadian utility regulators, including those in British Columbia, Alberta, and Newfoundland and Labrador, have recently accepted the use of USGAAP as the basis of regulatory accounting for utilities that they regulate.
[6] For examples, see: EB-2011-0210, DECISION ON PRELIMINARY ISSUE AND PROCEDURAL ORDER NO. 2 (Union Gas), March 1, 2012, pages 3-4 and EB-2011-0268, DECISION WITH REASONS (Hydro One), November 23, 2011, page 5.
[7] EB-2011-0268, DECISION WITH REASONS, November 23, 2011, page 12.

The adoption of USGAAP for both regulatory purposes and financial accounting would put OPG on the same reporting basis as U.S. utilities.

LIST OF ATTACHMENTS

Attachment 1:	*Financial Administration Act*, O. Reg. 395/11
Attachment 2:	OSC's Decision on OPG's application for an exemption to prepare financial statements in accordance with USGAAP
Attachment 3:	Aon Hewitt's "Transition Report for US GAAP from Canadian GAAP for Pension, Non-Pension Post Retirement, and Post-Employment Benefit Plans" for Ontario Power Generation Inc.

Numbers may not add due to rounding.

Table 4

Income and Other Taxes Variance Account[1]

Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
	Entry (i) **Scientific Research and Experimental Development ("SR&ED") Expenditures and Investment Tax Credits ("ITCs") for April 1, 2008 to February 28, 2011 Recognized after December 31, 2010**			
1	**Actual SR&ED ITCs @50%**[2]	(2.0)	0.0	0.0
2	**Actual Tax Benefit of SR&ED Capital Expenditures @100%**[2]	(5.1)	0.0	(0.9)
3	**Actual Tax on ITCs of Prior Periods @50%**[2]	0.7	1.5	(1.0)
4	**Addition to Variance Account** (line 1 + line 2 + line 3)	(6.4)	1.5	(1.9)
	Entry (ii) **Increase of SR&ED ITCs Recognition Percentage from 50% to 75% for April 1, 2008 to December 31, 2012**[3]			
	For April 1, 2008 to December 31, 2010 (recognized before January 1, 2011):			
5	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the December 31, 2010 Approved Balance of the Income and Other Taxes ("I&OT") Variance Account @ 50%**		(26.0)	
6	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 5 x 3/2)		(39.0)	
7	**Addition to Variance Account** (line 6 - line 5)	0.0	(13.0)	0.0
	For April 1, 2008 to February 28, 2011 (recognized after December 31, 2010):			
8	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the I&OT Variance Account after December 31, 2010 @ 50%** (line 1 + line 3)	(1.3)	1.5	(1.0)
9	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 8 x 3/2)	(1.9)	2.3	(1.5)
10	**Addition to Variance Account** (line 9 - line 8)	(0.6)	0.8	(0.5)
	For March 1, 2011 to December 31, 2012:			
11	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @50% - EB-2010-0008**[4]		(5.5)	(6.6)
12	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 11 x 3/2)		(8.2)	(9.8)
13	**Addition to Variance Account** (line 12 - line 11)	0.0	(2.7)	(3.3)
14	**Total Addition to Variance Account - SR&ED Expenditures and ITCs** (line 4 + line 7 + line 10 + line 13)	(7.0)	(13.5)	(5.7)
	Entry (iii) **Income Tax Variance Due to Income Tax Rate Reduction**			
15	**Forecast Regulatory Taxable Income - EB-2009-0174**[5]	120.6		
16	**Income Tax Rate Differential**[5] (26.50% - 31.21%)	-4.71%		
17	**Total Addition to Variance Account - Income Tax Rate Reduction** (line 15 x line 16 x 2/12)	(0.9)	0.0	0.0
	Entry (iv) **Income Tax Variance Due to Unburned Nuclear Fuel Adjustment**			
18	**Actual Unburned Nuclear Fuel Adjustment**	14.1		
19	**Income Tax Rate**	26.50%		
20	**Total Addition to Variance Account - Unburned Nuclear Fuel Adjustment** (line 18 x line 19 x 2/12)	0.6	0.0	0.0
	Entry (v) **Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment**			
	For April 1, 2008 to December 31, 2010:			
21	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		7.5	
22	**Additional Capital Cost Allowance**		17.0	
23	**Impact on Taxable Income** (line 21 - line 22)		(9.5)	
24	**Addition to Variance Account**[6] (line 23 x actual income tax rate applicable to each period)	0.0	(2.8)	0.0
	For January 1, 2011 to December 31, 2012:			
25	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**	0.1	0.7	4.9
26	**Additional Capital Cost Allowance**	0.8	4.0	4.4
27	**Impact on Taxable Income** (line 25 - line 26)	(0.7)	(3.3)	0.5
28	**Income Tax Rate**	26.50%	26.50%	25.0%
29	**Addition to Variance Account** (line 27 x line 28)	(0.2)	(0.9)	0.1
30	**Total Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (lines 24 + 29)	(0.2)	(3.7)	0.1
	Entry (vi) **Capital Tax Variance Due to Capital Tax Elimination**			
31	**Forecast Capital Tax - EB-2009-0174**[5]	16.5		
32	**Actual Capital Tax (eliminated effective July 1, 2010)**	0.0		
33	**Total Addition to Variance Account - Capital Tax Elimination** (line 32- line 31) x 2/12	(2.8)	0.0	0.0
34	**Grand Total Addition to Variance Account** (line 14 + line 17 + line 20 + line 30 + line 33)	(10.3)	(17.2)	(5.5)

Notes:

1 The six entries into the account for 2011 and 2012 are discussed in Ex. H1-1-1 Section 4.2.

2 Amounts in col. (a) relating to Jan-Feb 2011 have been determined as 2/12 of the actual annual 2011 amounts.
Amounts in col. (a) also include adjustments, based on the 2010 tax returns filed in 2011, to the variances included in the December 31, 2010 approved balance of the account.
Amounts in col. (c) include the forecast tax on ITCs recorded in 2011, which are taxed in 2012. Amounts in cols. (b) and (c) also include offsetting inter-period financial statement reconciliation adjustments of $1.5M and ($1.5M), respectively, which do not impact the total transactions in the account over the 2011-2012 period.

3 The increase in the percentage of SR&ED ITCs recognized for accounting purposes from 50% to 75% occurred in 2011.

4 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 4 - 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 Investment Tax Credits of Prior Periods (from EB-2010-0008, Ex. F4-2-1 Table 5, line 11) x tax rate (26.50% for 2011 and 25.00% for 2012)	2.3	2.2	4.5
4a	Total Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods from EB-2010-0008 (lines 1a + 2a +3a)	(6.5)	(6.6)	(13.1)
5a	Mar-Dec 2011 Amount ((line 4a, col. (c) / 24 months) x 10 months)	(5.5)		
6a	2012 Amount ((line 4a, col. (c) / 24 months) x 12 months)		(6.6)	

5 The annual forecast amounts for 2011 and the forecast income tax rate of 31.21% have been determined in accordance with EB-2009-0174 and are the same as those used to calculate the 2010 addition to the I&OT Variance Account, which was approved for recovery in EB-2010-0008.

6 The following actual tax rates are applied to amounts for the respective years included in line 23: 31.50% for 2008; 31.00% for 2009; 29.00% for 2010.

Table 6
Impact for USGAAP Deferral Account[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Projected 2012 Regulated Hydroelectric	Projected 2012 Nuclear	Projected 2012 Total
		(a)	(b)	(c)
	Transition Impacts Calculated as of January 1, 2011 (Actual):			
1	**Addition to Deferral Account for Previously Unrecognized Long-Term Disability Benefits Costs Recognized on Transition to USGAAP**[2]	1.4	30.0	31.4
	Transition Impacts Calculated for Year Ending December 31, 2011 (Actual):			
2	**Long-Term Disability Benefits Costs under USGAAP**[3]	1.6	33.8	35.4
3	**Long-Term Disability Benefits Costs under CGAAP**[3]	1.2	24.9	26.1
4	**Addition to Deferral Account** (line 2 - line 3)	0.4	8.9	9.3
	Implementation Impacts Calculated for Year Ending December 31, 2012 (Projected):			
5	**Long-Term Disability Benefits Costs under USGAAP**[4]	1.3	25.4	26.7
6	**Long-Term Disability Benefits Costs under CGAAP**[4]	1.1	22.4	23.5
7	**Addition to Deferral Account** (line 5 - line 6)	0.2	3.0	3.2
8	**Addition to Deferral Account for Regulatory Tax Impact** ((line 1 + line 4 + line 7) x 25.00% / (1 - 25.00%))	0.7	14.0	14.6
9	**Total Addition to Deferral Account** (line 1 + line 4 + line 7 + line 8)	2.7	55.9	58.5

Notes:
1. OPG's adoption of USGAAP and the resulting additions to the deferral account are discussed in Ex. A3-1-2.
2. Amounts represent the regulated portion of total OPG costs of $39.6M recognized on transition, as found on pages 5 and 10 of Ex. A3-1-2, Attachment 3.
3. Amounts represent the regulated portion of total OPG LTD benefits costs of $45.1M under USGAAP and $33.2M under CGAAP, as found on page 5 of Ex. A3-1-2, Attachment 3.
4. Amounts represent the regulated portion of total OPG LTD benefits costs of $29.3M under CGAAP and $33.3M under USGAAP, as found on page 3 of Ex. H2-1-3, Attachment 4.

UPDATE FOR AUDITED ACTUAL BALANCES FOR DEFERRAL AND VARIANCE ACCOUNTS AND OTHER INFORMATION

1.0 PURPOSE

The purpose of this exhibit is to provide the audited actual deferral and variance account balances at December 31, 2012 and to update OPG's calculation of payment riders proposed for the clearance of these account balances and resulting consumer impacts. The exhibit also provides projections of 2013 Pension and OPEB amounts.

2.0 SUMMARY OF BALANCES, RATE RIDERS AND CONSUMER IMPACT

The tables accompanying this exhibit reproduce those originally filed in Ex. H1-1-1, Ex. H2-1-1 and Ex. I1-1-2. The tables have been updated to reflect audited actual balances and related information. Additional tables showing calculations of consumer impact estimates and Interim Period Shortfall Riders are also included.

Audited actual deferral and variance account balances at December 31, 2012 are presented in Ex. H1-1-2, Table 1, col. (d), along with the projected balances that were originally filed in col. (e) of that table. A continuity schedule showing actual additions, amortization and interest for each account during 2012 is provided at Ex. H1-1-2 Table 1c. Actual balances have been audited by OPG's auditor, Ernst & Young LLP. The auditors' report on the account balances is provided as Attachment 1 to this exhibit. Section 3 discusses the actual audited 2012 balances and entries in the deferral and variance accounts with the more significant balances and those with material differences between the actual balances and the originally filed projections.

Overall, the total audited actual December 31, 2012 balances for recovery are debit balances of $110.9M for regulated hydroelectric and $1,159.2M for nuclear as shown in Ex. H1-1-2 Tables 16 and 17, respectively. Compared to the projected balances originally filed, the total regulated hydroelectric debit balance for recovery has increased by $6.4M from the projection of $104.5M. The total nuclear debit balance for recovery has decreased by $58.9M from the projection of $1,218.1M. The main driver of the increase in the total regulated hydroelectric balance is the higher Hydroelectric Water Conditions Account debit balance. The main drivers of the decrease in the total nuclear balances are lower additions to the Bruce Lease Net Revenues Variance Account and Pension and OPEB Cost Variance Account debit balances, partially offset by higher additions to the debit balance in the Nuclear Liability Deferral Account.

There are no changes to OPG's clearance proposal for the accounts, including amortization periods and methods for calculating the payment riders and Interim Period Shortfall Riders. The calculations of the payment riders, effective January 1, 2013, are shown in Ex. H1-1-2 Table 16 for regulated hydroelectric and Table 17 for nuclear. The resulting riders are $2.60/MWh for regulated hydroelectric and $8.34/MWh for nuclear. As the implementation date of the proposed riders is uncertain, OPG has calculated Interim Period Shortfall Riders assuming implementation dates of March 1, 2013 and April 1, 2013, as presented in Ex. H1-1-2 Table 23.

The increase in OPG's overall weighted average rate remains at 8 percent, as shown in Ex. H1-1-2 Table 21. The bill impact for a typical residential consumer of the above riders is estimated to be $1.66 per month, or a 1.4 per cent increase on a typical monthly bill of $116.30, as shown in Ex. H1-1-2 Table 22. This impact is slightly lower than the increase of $1.70 per month, or 1.5 per cent on a typical monthly bill originally filed.

3.0 DISCUSSION OF VARIANCES FROM 2012 PROJECTED BALANCES

This section discusses the actual audited 2012 balances and entries in the deferral and variance accounts with the more significant balances and those with material differences between the actual balances and the originally filed projections. The main reasons for those differences are provided in this section. For those accounts not specifically discussed below, the explanations of the balances entries in the accounts originally filed remain applicable.

3.1 Deferral and Variance Accounts Common to Hydroelectric and Nuclear

This section discusses the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account.

3.1.1 Pension and OPEB Cost Variance Account

The 2012 year-end audited debit balance in the Pension and OPEB Cost Variance Account is $15.1M for regulated hydroelectric and $309.1M for nuclear, as compared to the projected balance of $16.7M for regulated hydroelectric and $333.1M for nuclear as shown in Ex. H1-1-2 Table 1. The calculation of the 2012 additions to the account is shown in Ex. H1-1-2 Tables 5 and 5a. The same accounting standards and actuarial methodologies were applied in determining these 2012 additions as those reflected in the EB-2010-0008 payment amounts as well as those applied in determining the 2011 additions. As required by the OEB's EB-2011-0090 decision and order, OPG has included an unqualified audit opinion from Ernst & Young LLP as Attachment 2, which confirms that the 2012 account balance has been recorded on a CGAAP basis using the methodology reflected in EB-2010-0008 (Attachment 2, page 5). As required by the above decision and order, OPG also has provided an independent actuary's report from Aon Hewitt (Attachment 3), which supports:

- the amounts recorded in the variance account for 2012,
- the underlying 2012 actual pension and OPEB amounts, and
- the methodologies, assumptions and calculations used to derive these amounts.

In the charts on pages 5 and 8, Attachment 2 provides the details of the 2012 variance in pension and OPEB costs and associated tax impacts, respectively. These are also shown in Ex. H1-1-2 Tables 5 and 5a, respectively. The December 31, 2011 assumptions used to determine the 2012 costs are provided at page 6 of Attachment 2 in the schedule accompanying the auditors' report and at pages 6 to 8 of the independent actuary's report (Attachment 3). The assumptions are unchanged from those used to determine the 2012 projected costs in the original filing. Therefore, the assumptions for the projected costs presented in Chart 1 of Ex. H2-1-3 and Chart 1 in response to interrogatory L-1-1 Staff-24 continue to apply to the 2012 actual costs. The assumptions found in these charts are reproduced as part of Chart 6 below.

Attachment 3 (pages 5, 9 and 10) provides OPG's total pension and OPEB costs for 2012 in accordance with CGAAP and USGAAP. OPG's total actual pension contributions and OPEB payments for 2012 are provided at pages 9 and 10 of Attachment 3. The additions to the variance account in 2012 are based on the portion of these CGAAP costs and contributions/payments attributable to the prescribed assets. The same methodology was used to attribute these amounts to the regulated hydroelectric and nuclear businesses as that reflected in the EB-2010-0008 approved payment amounts and referenced in response to interrogatory L-1-1 Staff-14.

No amounts were recorded in the Pension and OPEB Cost Variance Account during 2012 related to financial impacts of OPG's adoption of USGAAP.

The 2012 year-end balance in the variance account is slightly lower than the originally filed projected balance due to lower-than-projected account additions during the year. The actual additions are $11.0M for regulated hydroelectric and $214.0M for nuclear, as shown in Ex. H1-1-2, Table 5, compared to a projection of $12.6M for regulated hydroelectric and $237.7M for nuclear. The actual additions reflect the finalization and audit of the year-end 2012 actuarial valuations of the pension and OPEB amounts.

3.1.2 Impact for USGAAP Deferral Account

The 2012 year-end audited debit balance in the Impact for USGAAP Deferral Account is $2.8M for regulated hydroelectric and $60.3M for nuclear, including $0.8M of interest. These are largely consistent with the originally filed projected balances of $2.7M for regulated hydroelectric and $56.7M for nuclear, including $0.8M of interest. The calculation of the actual 2012 additions to the account is shown in Ex. H1-1-2, Table 6. As originally projected, the addition relates to the financial impact on OPG's prescribed assets of the difference in the treatment of long-term disability ("LTD") benefit plan costs under USGAAP as compared to CGAAP, as discussed in Ex. A3-1-2 and related interrogatories. The actual and projected additions were determined in the same manner and using the same methodologies, including those used to attribute amounts to each of regulated hydroelectric and nuclear businesses as described in response to L-6-1 Staff-34 and other interrogatories. The following Chart 1 summarizes the components of the actual addition for the LTD cost impact recorded in the deferral account in 2012, in the same format as Chart 1 at p. 4 of Ex. A3-1-2.

Chart 1
Components of Actual 2012 Addition to Impact for USGAAP Deferral Account

Line	Cost Component	Amount ($M)
	Transition Costs:	
1	LTD costs recognized on the opening USGAAP balance sheet arising from the 2012 Restatement	31.4
2	Differences in CGAAP and USGAAP costs for 2011 arising from the 2012 Restatement (actual)	9.3
3	Total Transition Costs (lines 1 + 2)	40.7
4	Implementation Costs: Differences in CGAAP and USGAAP costs for 2012 (actual)	6.0
5	Tax Impact	15.6
	TOTAL (lines 3 + 4 + 5)	62.2

3.2 Hydroelectric Deferral and Variance Accounts

The only significant change from the projected balances of the regulated hydroelectric accounts is for the Hydroelectric Water Conditions Variance Account.

3.2.1 Hydroelectric Water Conditions Variance Account

The 2012 year-end audited debit balance in the Hydroelectric Water Conditions Variance Account is $17.1M, compared to the originally filed projected balance of $10.3M, as shown in Ex. H1-1-2, Table 1, due to higher-than-forecast additions to the account during the year. The actual additions for 2012 were $20.4M compared to the forecast of $13.7M. The higher actual additions, the calculation of which is shown in Ex. H1-1-2, Table 2, were due to actual water flows in 2012 being lower than originally projected. The lower actual water flows and the resulting lower calculated production of 17,638 GWh as compared to the projection of 17,951 GWh, reflected a deterioration of water supply conditions affecting the Niagara and St. Lawrence Rivers in the latter half of 2012 due to lower than normal precipitation in the lower Great Lakes basin.

3.3 Nuclear Deferral and Variance Accounts

The main changes from the projected balances of the nuclear accounts are in the Bruce Lease Net Revenues Variance Account, the Nuclear Liability Deferral Account and the Nuclear Development Variance Account.

<u>3.3.1 Bruce Lease Net Revenues Variance Account</u>

The 2012 year-end audited debit balance in the Bruce Lease Net Revenues Variance Account is $310.5M, compared to the projected balance of $368.2M, as shown at Ex. H1-1-2, Table 1, due to lower additions during the year. The calculation of additions to the account is shown in Ex. H1-1-2 Table 14. The actual revenues earned by OPG in 2012 under the Bruce Lease Agreement and associated agreements ("Bruce Lease") and the related costs incurred by OPG in 2012 with respect to the Bruce Nuclear Generating Stations are presented in Ex. H1-1-2 Table 14a. These revenue and cost amounts were determined on the same basis as the original projection in Ex. H1-1-1 Table 14a.

The additions to the account were lower due to higher-than-projected Bruce Lease revenues net of costs for 2012. As shown in the tables referenced above, the costs exceeded revenues by $260.8M in 2012 compared to a projection of costs exceeding revenues by $316.7M.

The difference in revenues net of costs relates primarily to higher-than-forecast supplemental rent revenue as a result of a lower than projected reduction in revenue from the derivative embedded in the Bruce Lease following the extension of the estimated average service life of the Bruce B station from 2014 to 2019. The extension of the Bruce B service life for accounting purposes is discussed in response to interrogatory L-2-2 AMPCO-06. Supplemental rent revenue and changes in the fair value of the derivative are discussed in more detail in section 3.3.1.1 below.

Higher-than-forecast earnings on the nuclear segregated funds also contributed to higher actual net revenues for 2012. As shown in Ex. H1-1-1 Table 14a and Ex. H1-1-2 Table 14a, respectively, the earnings were projected at $322.3M while the actual earnings for the year were $350.9M. The higher earnings primarily reflected the favourable impact of the performance of global financial markets on the value of the Decommissioning Fund.

The above factors resulting in higher-than-projected Bruce Lease net revenues were partly offset by a lower future income tax credit amount of $44.0M compared to a forecasted credit amount of $62.6M. This difference resulted mainly from the lower actual increase in the fair value of the derivative discussed above. The calculation of income taxes reflected in the 2012 actual net revenues is provided in Ex. H1-1-2 Table 14b.

The actual 2012 net revenues also reflected revenues of $5.8M for low and intermediate level waste management services, which were $9.0M lower than the projected revenues of $14.8M as a result of reduced waste volumes received from Bruce Power L.P. ("Bruce Power"). As indicated in the non-confidential version of the response to interrogatory L-2-2 AMPCO-07, the actual volumes were approximately 60 to 70 per cent lower than those projected due to volume reduction initiatives by Bruce Power. The figures for the actual and projected volumes are provided in the confidential version of the response to the above interrogatory. As noted in Ex. H2-1-2, section 4.3 and discussed in the above interrogatory, OPG's revenue projections for the waste management services are based on forecast waste volume information from normal operations received from Bruce Power, and OPG is required to maintain capacity to accept all such waste.

3.3.1.1 Supplemental Rent and Embedded Derivative

The originally filed projection included a reduction in 2012 supplemental rent revenue resulting from the increase in the fair value of the derivative of approximately $306.1M, due to the extension of the Bruce B estimated average service life for accounting purposes. The actual reduction in revenue recognized in accordance with CGAAP and USGAAP by OPG in 2012 associated with the life extension was $248.7M. The lower-than-projected revenue reduction was primarily due to an increase during the second half of 2012 in expected average HOEP values for the 2015-2019 period.

The actual life extension adjustment to the derivative value and the underlying parameters and assumptions were determined using the same methodology and valuation model as described in response to interrogatories L-1-1 Staff-10 and L-1-7 SEC-05 and reflected in the calculation of the originally filed projected adjustment value of $306.1M. The details of the valuation of that adjustment were provided in Attachment 1, p. 3 and Attachment 2, p. 2 to the above interrogatories, respectively.

At page 2, Attachment 4 to this exhibit presents the results of the valuation of the actual adjustment of $248.7M in the same format as Attachment 1, p. 3 of L-1-1 Staff-10. Attachment 5 to this exhibit provides the specific parameters, including forward price data for HOEP, reflected in the calculation of the valuation results in the same format as Attachment 2, p. 2 of L-1-7 SEC-05.

In addition to the above, owing mainly to a higher expected average HOEP for the pre-life extension period of the Bruce B station through to the end of 2014, the fair value of the derivative related to this period decreased by $7.5M during the second half of 2012. At the end of June 2012, the fair value related to the pre-life extension period (including 2012) was calculated at $228.8M, as shown in L-1-1 Staff-10, Attachment 1, p. 2, while the equivalent value at the end of 2012, as shown in Attachment 4, p.1 to this exhibit, is $221.3M (including the amount of the rebate payable of $77.9M for 2012 discussed below).[1] These values were also consistently determined using the above-noted methodology, valuation model, parameters and assumptions.

The actual annual arithmetic average of HOEP for 2012 was below $30/MWh at $22.80/MWh (as also shown in response to undertaking JT1.1). As such, in accordance with the Bruce Lease, OPG is required to provide a rent rebate to Bruce Power of $77.9M for 2012 supplemental rent payments received by OPG. As explained at Ex. H2-1-2, p. 4, lines 13-16 and in response to interrogatory L-1-1 Staff-09, the payment of the rebate does not typically

[1] Although the derivative liability is reduced by the amount of the unconditional rebate payable at the end of 2012 via a transfer of the payable to an accrued liability (see footnote 2), the cited value of $221.3M for derivative at year-end 2012 (presented in Attachment 4, p.1) has not been reduced by the 2012 rebate amount in order to provide an appropriate basis of comparison with the mid-year derivative value of $228.8M.

impact the amount of revenue recognized for accounting purposes; this is the case for the 2012 rent rebate. Rather, the payment of the rebate results in a reduction in the derivative liability, as it does for 2012.[2] The journal entries recorded during 2012 in respect of the impact of the embedded derivative on supplemental rent revenue and the rent rebate are summarized in Attachment 6 in the same format as the projected entries originally provided in response to interrogatory L-1-1 Staff-09 (b).

Chart 2 below provides the components of actual supplemental rent revenue for 2010, 2011 and 2012 recognized by OPG in accordance with CGAAP and USGAAP. The information is provided as an update to, and in the same format as, Chart 1 in response to interrogatory L-1-1 Staff-11 (a) and includes 2010 information in response to a request for such information made at the Technical Conference for this proceeding. (Tr. Technical Conference pp. 93 - 94)

Chart 2
Components of Supplemental Rent Revenue

$M	**2010 Actual**	**2011 Actual**	**2012 Actual**
Supplemental Rent Revenue – Un-refurbished Units	179.4	184.5	188.9
Supplemental Rent Revenue – Refurbished Units	–	–	2.5
Adjustment for changes in the fair value of the derivative embedded in the Bruce Lease	(45.0)	(23.5)	(283.5)
Net Supplemental Rent Revenue	**134.4**	**161.0**	**(92.1)**

The actual 2012 supplemental rent revenue of $2.5M for the refurbished units (Bruce A, Units 1 and 2) reflects the beginning of commercial operation of these units in Q4 2012. As noted at page 2, lines 14-16 of the response to interrogatory L-1-1 Staff-11 (a), the originally

[2] As the actual physical cash disbursement for the 2012 rebate occurs in 2013, the reduction of the derivative liability at the end of 2012 was recorded as an increase to an accrued payable (consistent with the principles of accrual accounting). Derivative accounting does not apply to this unconditional liability.

filed projection assumed an earlier commercial operation date and therefore included a higher forecast revenue amount of $8.0M for these units.

3.3.2 Nuclear Liability Deferral Account

The 2012 year-end audited debit balance in the Nuclear Liability Deferral Account is $208.0M compared to the projected balance of $181.7M, as shown in Ex. H1-1-2, Table 1. The balance is higher than projected due to higher actual additions to the account, the calculation of which is shown in Ex. H1-1-2 Table 9. The actual additions for 2012 were $206.2M compared to a forecast of $180.0M. The difference is due to a higher income tax impact component of the 2012 additions, which reflected lower actual contributions to the segregated funds per the segregated fund contribution schedule approved by the Province in December 2012 based on the 2012 ONFA Reference Plan.[3]

Updated continuity schedules showing actual 2012 amounts for OPG’s nuclear asset retirement obligation (“ARO”), nuclear segregated funds, and asset retirement costs (“ARC”) for each of prescribed facilities and Bruce facilities are provided in Ex. H1-1-2 Tables 18 and 19, respectively. Ex. H1-1-2 Table 20 includes the details of the actual 2012 year-end adjustments to the ARO and ARC, which were recorded at a discount rate of 3.50%.

3.3.3 Nuclear Development Variance Account

The 2012 year-end debit balance in the Nuclear Development Variance Account is $30.2M as compared to the projected balance of $37.2M originally filed, as shown in Ex. H1-1-2, Table 1, due to lower-than-projected additions during the year. The calculation of the additions is found at Ex. H1-1-2 Table 10. The lower 2012 additions were primarily due to lower costs for vendor selection/project planning and stakeholder consultation for New Nuclear at Darlington (“NND”) as shown in Chart 3 below. An updated discussion of NND expenditures can be found in the updated response to interrogatory L-1-7 SEC-17.

[3] As noted in Ex. H2-1-1, segregated fund contributions are deductible by OPG in calculating taxable income and therefore affect income taxes.

Chart 3
Expenditures for New Nuclear at Darlington

2011 + 2012 Combined - $M	Total Per Initial Filing	Updated Total	Variance
Regulatory Hearings	3.3	2.7	0.6
Regulatory Compliance	14.8	14.1	0.7
Site Readiness	5.1	4.4	0.7
Vendor Selection/Project Planning	19.4	17.4	2.0
Stakeholder Consultation	6.9	3.8	3.1
Total	**49.4**	**42.5**	**6.9**

4.0 UPDATED PROJECTIONS OF 2013 PENSION AND OPEB AMOUNTS

Using the same methodology as described in Ex. H2-1-3, section 4.2, OPG's updated projection of the total 2013 additions to the Pension and OPEB Cost Variance Account is $399.0M. The details of the projected 2013 additions are provided in Chart 4 below, which is presented in the same format as Chart 2 in Ex. H2-1-3. The calculations of the amounts in Chart 4 can be found in the updated response to interrogatory L-1-7 SEC-23. In addition, as requested at the Technical Conference for this proceeding (Tr. Technical Conference p. 72), Chart 5 below provides a breakdown, by cost component, of the projected 2013 pension and OPEB cost variances from Chart 4 in the same format as provided at page 2 of the response to interrogatory L-2-1 Staff-23.

The above projections were developed using updated estimates of OPG's 2013 pension and OPEB costs based on the actual values of the benefit obligations and pension fund assets as at December 31, 2012 and the final assumptions made at that time.[4] These assumptions, including the actual discount rates as of the end of 2012, are provided in Chart 6 below. This chart is presented in the same format as Chart 1 provided in the response to interrogatory L-2-1 Staff-24. The discount rates as of the end of 2012 were provided by an independent actuary and were determined in the manner described in the responses to interrogatories L-2-1 Staff-24 and L-4-7 SEC-32.

The increase in the estimated 2013 additions to the variance account as compared to the originally filed projection of $367.2M is primarily due to a further decline in discount rates noted in the response to interrogatory L-2-1 Staff-24 (a). The discount rates continue to reflect the downward trend in long-term bond rates under the current financial market conditions.

Based on the above projections, the estimated 2013 financial impact on the prescribed assets of the difference in the accounting treatment of the LTD benefit plan costs as a result of OPG's adoption of USGAAP, noted in section 4.1 above, is a reduction in the costs of approximately $3.2M to be credited to customers as projected additions to the Impact for USGAAP Deferral Account in 2013.

Chart 4
2013 Projected Additions to the Pension and OPEB Cost Variance Account[1]

$M	**Regulated Hydro**	**Nuclear**	**Total**
Pension Costs	12.8	223.8	236.6
OPEB Costs	5.3	84.0	89.3
Tax Impact	3.8	69.2	73.0
Total	**21.9**	**377.0**	**399.0**

[1] Numbers may not add due to rounding

[4] These final assumptions apply equally to the determination of OPG's 2013 pension and OPEB costs under both CGAAP and USGAAP, with the exception that the discount rate assumptions for LTD benefit plan costs under USGAAP must be determined as of 2013 year-end.

Chart 5
Components of 2013 Projected Pension and OPEB Cost Variances[1]

Components of Net Periodic Pension and Benefit Cost *$M*	2013 Pension Variance Amount	2013 OPEB Variance Amount
Employer current service cost	105.6	40.9
Interest cost	(7.0)	3.9
Expected return on plan assets	(30.6)	n/a
Amortization of past service costs	(3.8)	(1.1)
Amortization of net actuarial loss (gain)	172.4	45.6
Total	**236.6**	**89.3**

[1] Numbers may not add due to rounding

Chart 6
Pension and OPEB Assumptions

Assumption	2011 Actual	2012 Actual[1]	2013 Projection	2011 OEB-Approved	2012 OEB-Approved
Discount rate for pension	**5.80% per annum**	**5.10% per annum**	**4.30% per annum**	6.80% per annum	6.80% per annum
Discount rate for other post retirement benefits	**5.80% per annum**	**5.20% per annum**	**4.40% per annum**	7.00% per annum	7.00% per annum
Discount rate for long- term disability	**4.70% per annum**	**4.00% per annum**	**3.50% per annum**	5.25% per annum	5.25% per annum
Expected long-term rate of return on pension fund assets	**6.5% per annum**	**6.5% per annum**	**6.25% per annum**	7.0% per annum	7.0% per annum
Inflation rate	**2.0% per annum**	**2.0% per annum**	**2.0% per annum**	2.0% per annum	2.0% per annum
Salary schedule escalation rate	**3.0% per annum**	**3.0% per annum**	**2.5% per annum**	3.0% per annum	3.0% per annum
Rate of return used to project year-end pension fund asset values	**N/A**	**N/A**	**N/A**	9.0% in 2009 and 7.0% per annum in 2010	9.0% in 2009 and 7.0% per annum in each of 2010 and 2011

[1] The actual assumptions for 2012 are unchanged from the assumptions for 2012 projections presented in Ex. H2-1-3, Chart 1 and L-1-1 Staff-24.

LIST OF ATTACHMENTS

Attachment 1:	Independent Auditors' Report on OPG's Deferral and Variance Account Balances as at December 31, 2012
Attachment2:	Independent Auditors' Report on the Pension and OPEB Cost Variance Account as at December 31, 2012
Attachment 3:	Aon Hewitt's "Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Year 2012 and in Support of Pension and OPEB Cost Variance Calculations" for Ontario Power Generation Inc.
Attachment 4:	Year-End 2012 Derivative Valuation
Attachment 5:	Parameter Values for Year-End 2012 Derivative Valuation
Attachment 6:	2012 Journal Entries for Embedded Derivative Liability

INDEPENDENT AUDITORS' REPORT

To the management of Ontario Power Generation Inc.

We have audited the accompanying schedule of regulatory balances of **Ontario Power Generation Inc.** as at December 31, 2012 (the "Schedule"). The Schedule has been prepared by management to present the balances of the regulatory assets and liabilities of **Ontario Power Generation Inc.** representing the variance and deferral accounts authorized for **Ontario Power Generation Inc.** by the decisions and orders of the Ontario Energy Board, including those pursuant to *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998,* using the basis of accounting described in Note 1 to the Schedule.

Management's responsibility for the schedule of regulatory balances
Management is responsible for the preparation and the fair presentation of this Schedule in accordance with the basis of accounting described in Note 1 to the Schedule (this includes determining that the basis of accounting is an acceptable basis for the preparation of the Schedule in the circumstances) 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 auditor considers 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 regulatory assets and liabilities of **Ontario Power Generation Inc.** as at December 31, 2012 representing the variance and deferral accounts authorized for **Ontario Power Generation Inc**. by the decisions and orders of the Ontario Energy Board, including those authorized pursuant to *Ontario Regulation 53/05*, under the *Ontario Energy Board Act, 1998*, using the basis of accounting 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]

ERNST & YOUNG LLP
Chartered Accountants
Licensed Public Accountants

TORONTO, CANADA
February 6, 2013

SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2012

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. ("OPG" or the "Company") receives regulated prices for electricity generated from most of its baseload 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*, and are recognized by OPG as regulatory assets and liabilities in its consolidated financial statements, which are prepared in accordance with United States generally accepted accounting principles ("US GAAP") beginning January 1, 2012.

OPG's significant accounting policies related to accounting for rate regulated operations are outlined in Note 3 to its consolidated financial statements as at and for the year ended December 31, 2011, prepared in accordance with Canadian generally accepted accounting principles as determined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting, with significant changes to the policies resulting from OPG's required conversion to US GAAP effective January 1, 2012 discussed in Note 2 to its condensed interim consolidated financial statements as at and for the three months ended March 31, 2012.

During the year ended December 31, 2012, OPG recorded additions to the variance and deferral accounts authorized by the OEB's decisions and orders, including those authorized pursuant to *Ontario Regulation 53/05*, and amortized the approved regulatory balances as at December 31, 2010 based on recovery periods established by the OEB's decision and order under case number EB-2010-0008. OPG also recorded interest on outstanding regulatory balances during the year ended December 31, 2012 at the interest rate of 1.47 percent per annum prescribed by the OEB.

The regulatory assets representing the balances in the authorized variance and deferral accounts recorded by OPG as at December 31, 2012 were as follows:

(millions of dollars)	**2012**
Regulatory assets	
Pension and OPEB Cost Variance Account – Nuclear	**309**
Pension and OPEB Cost Variance Account – Hydroelectric	**15**
Bruce Lease Net Revenues Variance Account	**311**
Tax Loss Variance Account – Nuclear	**254**
Tax Loss Variance Account – Hydroelectric	**48**
Nuclear Liability Deferral Account	**208**
Impact for USGAAP Deferral Account – Nuclear	**60**
Impact for USGAAP Deferral Account – Hydroelectric	**3**
Ancillary Services Net Revenue Variance Account – Nuclear	**2**
Ancillary Services Net Revenue Variance Account – Hydroelectric	**34**
Nuclear Development Variance Account	**30**
Hydroelectric Water Conditions Variance Account	**17**
Capacity Refurbishment Variance Account – Nuclear	**13**
Capacity Refurbishment Variance Account – Hydroelectric	**1**
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**7**
Hydroelectric Surplus Baseload Generation Variance Account	**4**
Total regulatory assets	**1,316**

See accompanying note to the schedule

The regulatory liabilities representing the balances in the authorized variance and deferral accounts recorded by OPG as at December 31, 2012 were as follows:

(millions of dollars)	**2012**
Regulatory liabilities	
Income and Other Taxes Variance Account – Nuclear	**33**
Income and Other Taxes Variance Account – Hydroelectric	**2**
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	**4**
Hydroelectric Incentive Mechanism Variance Account	**2**
Total regulatory liabilities	**41**

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 regulatory assets and liabilities representing the balances in the variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. These regulatory assets and liabilities 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]

Donn W. J. Hanbidge
Chief Financial Officer

February 6, 2013

See accompanying note to the schedule

NOTE TO THE SCHEDULE OF REGULATORY BALANCES AS AT DECEMBER 31, 2012

1. BASIS OF ACCOUNTING

Beginning on January 1, 2012, OPG records regulatory assets and liabilities in accordance with US GAAP. 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 the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts 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, the Company records a regulatory liability. Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. 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.

The schedule of regulatory balances presents those regulatory assets and liabilities of OPG as at December 31, 2012 that represent the balances in the variance and deferral accounts authorized by the decisions and orders of the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The schedule does not include other regulatory assets and liabilities recognized by OPG in accordance with US GAAP in its consolidated financial statements. As such, the schedule excludes the regulatory asset recognized by OPG for the amount of deferred income taxes that are expected to be included in future regulated prices and recovered from, or paid to, customers. The schedule also excludes the regulatory asset recognized by OPG for the portion related to regulated operations of the unamortized amounts recorded in accumulated other comprehensive income ("AOCI") in respect of OPG's pension and other post employment benefit plans that have not yet been reclassified from AOCI to benefit costs.

The consolidated financial statements of OPG as at and for the year ended December 31, 2011, prepared in accordance with Canadian GAAP, and its condensed interim consolidated financial statements as at and for the three, six and nine months ended March 31, 2012, June 30, 2012 and September 30, 2012, respectively, prepared in accordance with US GAAP, have been filed with the Ontario Securities Commission.

INDEPENDENT AUDITORS' REPORT

To the management of Ontario Power Generation Inc.

We have audited the accompanying schedule of the Pension and OPEB Cost Variance Account of **Ontario Power Generation Inc.** as at December 31, 2012 and 2011 (the "Schedule"). The Schedule has been prepared by management to present the balance of the regulatory asset of **Ontario Power Generation Inc.**, representing the Pension and OPEB Cost Variance Account established by the decision and order of the Ontario Energy Board under case number EB-2011-0090, using the basis of accounting described in Note 1 to the Schedule.

Management's responsibility for the schedule of the Pension and OPEB Cost Variance Account
Management is responsible for the preparation and the fair presentation of this Schedule in accordance with the basis of accounting described in Note 1 to the Schedule (this includes determining that this basis of accounting is an acceptable basis for the preparation of the Schedule in the circumstances) 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 auditor considers 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 balance of the regulatory asset of **Ontario Power Generation Inc.** as at December 31, 2012 and 2011, representing the Pension and OPEB Cost Variance Account established by the decision and order of the Ontario Energy Board under case number EB-2011-0090, using the basis of accounting 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]

ERNST & YOUNG LLP
Chartered Accountants
Licensed Public Accountants

TORONTO, CANADA
February 6, 2013

SCHEDULE OF THE PENSION AND OPEB COST VARIANCE ACCOUNT AS AT DECEMBER 31, 2012 AND 2011

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

In March 2011 and April 2011, respectively, under case number EB-2010-0008, the OEB issued its decision and order establishing new regulated prices for OPG's regulated generation effective March 1, 2011. In June 2011, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion to review and vary the part of the OEB's March 2011 decision related to pension and other post employment benefits ("OPEB") costs, under case number EB-2011-0090. Pursuant to the decision and order on the motion, the variance account records the difference between OPG's actual pension and OPEB costs attributed to the Prescribed Facilities, calculated in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting, and related tax impacts, and those reflected in the regulated prices established by the OEB's EB-2010-0008 decision and order. The OEB's June 2011 decision and order authorized the variance account to be in effect for the period from March 1, 2011 to December 31, 2012.

For the period from March 1, 2011 to December 31, 2012, OPG recorded additions to the Pension and OPEB Cost Variance Account in accordance with the OEB's June 2011 decision and order. During this period, OPG also recorded interest on the balance of the account at the interest rate of 1.47 percent per annum prescribed by the OEB.

The balance of the variance account is recognized as a regulatory asset in OPG's consolidated financial statements, which are prepared in accordance with United Stated generally accepted accounting principles ("US GAAP") beginning on January 1, 2012. OPG's significant accounting policies related to accounting for rate regulated operations are outlined in Note 3 to its consolidated financial statements as at and for the year ended December 31, 2011 prepared in accordance with Canadian GAAP, with significant changes to the policies resulting from OPG's required conversion to US GAAP effective January 1, 2012 discussed in Note 2 to its condensed interim consolidated financial statements as at and for the three months ended March 31, 2012.

The regulatory asset representing the balance of the Pension and OPEB Cost Variance Account, as calculated on the basis of OPG's pension and OPEB costs determined in accordance with Canadian GAAP, was recorded by OPG as at December 31, 2012 and 2011 as follows:

(millions of dollars)	**2012**	**2011**
Pension and OPEB Cost Variance Account – Nuclear		
Pension and OPEB cost variance *(Note 2)*	**254**	71
Tax impact variance *(Note 3)*	**51**	20
Interest	**4**	1
	309	92
Pension and OPEB Cost Variance Account – Regulated Hydroelectric		
Pension and OPEB cost variance *(Note 2)*	**12**	3
Tax impact variance *(Note 3)*	**3**	1
Interest	**-**	-
	15	4
Total Pension and OPEB Cost Variance Account balance	**324**	96

See accompanying notes to the schedule

This schedule of the Pension and OPEB Cost Variance Account 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 regulatory asset for the balance of the Pension and OPEB Cost Variance Account as at December 31, 2012 and 2011. This regulatory asset has 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]

Donn W. J. Hanbidge
Chief Financial Officer

February 6, 2013

See accompanying notes to the schedule

NOTES TO THE SCHEDULE OF THE PENSION AND OPEB COST VARIANCE ACCOUNT AS AT DECEMBER 31, 2012 AND 2011

1. BASIS OF ACCOUNTING

OPG records regulatory assets and liabilities in accordance with US GAAP. 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 the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts 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, the Company records a regulatory liability. Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. 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.

The schedule of the Pension and OPEB Cost Variance Account (the "Schedule") presents the balance of OPG's regulatory asset as at December 31, 2012 and 2011 for the Pension and OPEB Cost Variance Account established by the OEB's decision and order under case number EB-2011-0090. The Schedule does not include other regulatory assets and liabilities recognized by OPG in its consolidated financial statements in accordance with US GAAP beginning on January 1, 2012 and in accordance with Canadian GAAP prior to that date.

The consolidated financial statements of OPG as at and for the year ended December 31, 2011, prepared in accordance with Canadian GAAP, and its condensed interim consolidated financial statements as at and for the three, six and nine months ended March 31, 2012, June 30, 2012 and September 30, 2012, respectively, prepared in accordance with US GAAP, have been filed with the Ontario Securities Commission.

2. PENSION AND OTHER POST EMPLOYMENT BENEFITS COSTS

OPG's post employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, other post retirement benefits which include group life insurance and health care benefits, and long-term disability ("LTD") benefits. For the purposes of this Schedule, OPEB includes all post employment benefit plans of OPG with the exception of the registered pension plan. OPG does not maintain separate pension and OPEB plans for the Prescribed Facilities.

As per the OEB's decision and order under case number EB-2011-0090, OPG's pension and OPEB costs for the purposes of the Pension and OPEB Cost Variance Account are required to be calculated in accordance with Canadian GAAP. The pension and OPEB cost variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2012 and 2011 was calculated by comparing the portion of OPG's actual pension and OPEB costs calculated in accordance with Canadian GAAP and attributed to its nuclear and regulated hydroelectric generation facilities for the year ended December 31, 2012 and the ten-month period ended December 31, 2011 to the respective forecast amounts of such costs included in the regulated prices established by the OEB's EB-2010-0008 decision and order.

The pension and OPEB cost variance was determined as follows:

	January 1, 2012 to December 31, 2012					
	Nuclear			Regulated Hydroelectric		
(millions of dollars)	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Registered pension plan costs	**272**	**138**	**134**	**14**	**7**	**7**
Other post employment benefits costs	**212**	**163**	**49**	**10**	**8**	**2**
Total pension and OPEB costs	**484**	**301**	**183**	**24**	**15**	**9**

	March 1, 2011 to December 31, 2011					
	Nuclear			Regulated Hydroelectric		
(millions of dollars)	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Registered pension plan costs	162	115	47	8	6	2
Other post employment benefits costs	160	136	24	8	7	1
Total pension and OPEB costs	322	251	71	16	13	3

OPG's actual pension and OPEB costs for the years ended December 31, 2012 and 2011 were attributed to the Prescribed Facilities using a combination of specific identification and allocation of the applicable total OPG-wide amounts. The methodology used to attribute these amounts to the Prescribed Facilities is as outlined in OPG's application to, and approved in the decision and order of, the OEB under case number EB-2010-0008. The portion of the costs attributed to the Prescribed Facilities for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account did not include amounts related to the post employment benefit plans of the Nuclear Waste Management Organization ("NWMO"). The actual costs for the ten-month period ended December 31, 2011 were determined by applying a factor of 10/12 to the actual costs for the year ended December 31, 2011.

OPG's total pension and OPEB obligations and related costs for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account were determined in accordance with Canadian GAAP using the accounting standards and methodology outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008.

In accordance with Canadian GAAP, OPG's obligations for its pension and OPEB plans were calculated on an accrual basis. The obligations for pension and other post retirement benefits were determined using the projected benefit method pro-rated on service. The obligation for LTD benefits was determined using the projected benefit method on a terminal basis. These pension and OPEB obligations are impacted by factors including discount rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. OPG's pension and OPEB costs and obligations in accordance with Canadian GAAP have been calculated annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models used to calculate OPG's pension and OPEB obligations and related costs in accordance with Canadian GAAP. Assumptions for discount rates and inflation are two critical elements in the determination of these costs and obligations. In addition, the assumption for the expected rate of return on pension plan assets is a critical assumption in the determination of OPG's registered pension plan costs in accordance with Canadian GAAP. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by OPG's management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given period will often differ from actuarial assumptions because of economic and other factors. The impact of these updates and differences is accumulated and amortized over future periods in determining the costs in accordance with Canadian GAAP.

In accordance with Canadian GAAP, the discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligation for the Company's employee benefit plans. The expected rate of return on registered pension plan assets is based on current and expected asset allocation of the plan portfolio, as well as the expected return considering long-term historical risks and returns associated with each asset class within the portfolio. Pension plan assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

OPG's pension and OPEB costs calculated in accordance with Canadian GAAP include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments, including LTD benefits, are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan, and the resulting amortization is included as a component of recognized pension and OPEB costs. For each plan, including LTD benefits, the excess of the net cumulative unamortized gain or loss, over ten percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life of the employees, as the associated economic benefit is expected to be realized over that period. The resulting amortization is included as a component of the recognized costs.

Separate assumptions are not made to derive the Prescribed Facilities' pension and OPEB costs as OPG does not maintain separate benefit plans for these facilities. The main assumptions used to derive OPG's total actual pension and OPEB obligations and costs in accordance with Canadian GAAP, and therefore the portion of the costs attributed to the Prescribed Facilities, as at and for the years ended December 31, 2012 and 2011 are presented below. These assumptions exclude those relating to the post employment benefit plans of the NWMO.

	Registered and Supplementary Pension Plans		**Other Post Retirement Benefits**		**Long-Term Disability Benefits**	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**
Benefit Obligation at Year End						
Rate used to discount future benefits	**4.30%**	5.10%	**4.40%**	5.20%	**3.50%**	4.00%
Inflation rate	**2.00%**	2.00%	**-**	-	**2.00%**	2.00%
Salary schedule escalation rate	**2.50%**	3.00%	**-**	-	**-**	-
Cost for the Year						
Expected long-term rate of return on plan assets	**6.50%**	6.50%	**-**	-	**-**	-
Rate used to discount future benefits	**5.10%**	5.80%	**5.20%**	5.80%	**4.00%**	4.70%
Inflation rate	**2.00%**	2.00%	**-**	-	**2.00%**	2.00%
Salary schedule escalation rate	**3.00%**	3.00%	**-**	-	**-**	-

The disclosure related to OPG's pension and OPEB plans and costs contained in this Schedule is limited to that necessary to describe the information presented in this Schedule. This disclosure does not necessarily include all of the required disclosure under Canadian GAAP or US GAAP pertaining to OPG's pension and OPEB plans and costs. The required disclosure pertaining to OPG's pension and OPEB plans and costs for the year ended December 31, 2011 in accordance with Canadian GAAP is provided in the consolidated financial statements of OPG as at and for the year then ended, with additional disclosures in accordance with US GAAP included in the condensed interim consolidated financial statements of OPG as at and for the three months ended March 31, 2012 to provide a better understanding of the impact of the adoption of US GAAP on OPG's 2011 consolidated financial statement amounts.

3. INCOME TAXES

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations.

For the purposes of determining the balance of the Pension and OPEB Cost Variance Account as at December 31, 2012 and 2011, tax impacts were calculated using the methodology for determining regulatory income taxes outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008. Under this methodology, OPG follows the taxes payable method for the purposes of calculating the amount of regulatory income taxes for the Prescribed Facilities. In determining regulatory income taxes, OPG applies the statutory income tax rate to the regulatory taxable income of the Prescribed Facilities. Pension and OPEB costs are not deductible for the purposes of determining taxable income and are, therefore, added to regulatory earnings before tax. Pension plan contributions and OPEB payments are deductible in determining taxable income and are, therefore, deducted from regulatory earnings before tax.

The tax impact variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2012 and 2011 was calculated by comparing the actual regulatory income tax impact associated with the actual pension and OPEB costs discussed in Note 2, pension plan contributions and OPEB payments attributed to the Prescribed Facilities for the year ended December 31, 2012 and the ten-month period ended December 31, 2011 to the respective forecast income tax impacts included in the regulated prices established by the OEB's EB-2010-0008 decision and order.

The actual regulatory income tax impact was calculated by applying the statutory corporate income tax rates of 25 percent and 26.5 percent, respectively, to the net amount of additions to regulatory earnings before tax related to actual pension and OPEB costs, pension plan contributions and OPEB payments attributed to the Prescribed Facilities for the year ended December 31, 2012 and the ten-month period ended December 31, 2011. Additionally, the actual regulatory income tax impact included an amount, known as the "tax gross-up" and calculated at the respective income tax rates of 25 and 26.5 percent, related to taxes that will be payable by OPG upon recovery of the tax impact variance component of the Pension and OPEB Cost Variance Account. The methodology used to calculate the tax impact component of the Pension and OPEB Cost Variance Account, including the application of the tax gross-up, is as reflected in OPG's Notice of Motion under case number EB-2011-0090.

The tax impact variance was determined as follows:

	January 1, 2012 to December 31, 2012	
(millions of dollars except where noted)	**Nuclear**	**Regulated Hydroelectric**
Additions to regulatory earnings before tax		
Registered pension plan costs *(Note 2)*	**272**	**14**
Other post employment benefits costs *(Note 2)*	**212**	**10**
	484	**24**
Deductions from regulatory earnings before tax		
Registered pension plan contributions	**(283)**	**(14)**
Other post employment benefits payments	**(75)**	**(4)**
	(358)	**(18)**
Actual net addition to regulatory earnings before tax	**126**	**6**
Combined Canadian federal and provincial statutory income tax rate	**25%**	**25%**
Actual tax impact, including tax gross-up[1]	**42**	**2**
Forecast tax impact, including tax gross-up	**11**	**-**
Tax impact variance	**31**	**2**

[1] The amount is computed by dividing the product of the net addition to regulatory earnings before tax and the statutory income tax rate by one minus the statutory income tax rate.

	March 1, 2011 to December 31, 2011	
(millions of dollars except where noted)	**Nuclear**	**Regulated Hydroelectric**
Additions to regulatory earnings before tax		
Registered pension plan costs *(Note 2)*	162	8
Other post employment benefits costs *(Note 2)*	160	8
	322	16
Deductions from regulatory earnings before tax		
Registered pension plan contributions	(187)	(9)
Other post employment benefits payments	(54)	(3)
	(241)	(12)
Actual net addition to regulatory earnings before tax	81	4
Combined Canadian federal and provincial statutory income tax rate	26.5%	26.5%
Actual tax impact, including tax gross-up[1]	29	1
Forecast tax impact, including tax gross-up	9	-
Tax impact variance	20	1

[1] The amount is computed by dividing the product of the net addition to regulatory earnings before tax and the statutory income tax rate by one minus the statutory income tax rate.

OPG's registered pension plan contributions and OPEB payments for the years ended December 31, 2012 and 2011 were attributed to the Prescribed Facilities in proportion to the respective attributed benefit costs discussed in Note 2. This methodology was reflected in OPG's application to the OEB under case number EB-2010-0008. The portion of the pension contributions and OPEB payments attributed to the Prescribed Facilities for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account did not include amounts related to the benefit plans of the NWMO. The actual contributions and payments for the ten-month period ended December 31, 2011 were determined by applying a factor of 10/12 to such actual contributions and payments attributed to the Prescribed Facilities for the year ended December 31, 2011.

OPG made contributions to its registered pension plan during 2012 and 2011 based on the most recently filed actuarial funding valuation of the plan, which was prepared as of January 1, 2011.

Actuarial Report

Ontario Power Generation Inc.

Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Year 2012 and in Support of Pension and OPEB Cost Variance Calculations

January 1, 2012 to December 31, 2012

Contents

Introduction

This report summarizes the accounting costs for fiscal year 2012 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon Hewitt has prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the balance in OPG's Pension and OPEB Cost Variance Account for the year ended December 31, 2012. We understand this report is expected to be filed with the Ontario Energy Board ("OEB").

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP") ;
- Non-pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post Employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal year from January 1, 2012 to December 31, 2012. The results have been developed in accordance with US generally accepted accounting principles ("US GAAP") under ASC 715, 712 and 710 and Canadian generally accepted accounting principles ("Canadian GAAP") under CICA Handbook–Accounting (Part V), Section 3461 ("CICA 3461").

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG's consolidated financial statements.

Unless otherwise stated all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2011 disclosure reports ("the Reports") prepared by Aon Hewitt in accordance with Canadian GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated February, 2012 and are titled as follows:

- CICA 3461 Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- CICA 3461 Accounting Information – Pension Plans.

All figures are shown in Canadian $000s.

Sincerely,

Aon Hewitt Inc.

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

February 2013

Pension and OPEB Cost Variance Account

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's decision, issued in March 2011 under case number EB-2010-0008, with respect to pension and OPEB costs. In June 2011, under case number EB-2011-0090, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion. The variance account records the difference between actual pension and OPEB costs under Canadian GAAP for OPG's regulated operations and related tax impacts, and those reflected in the regulated prices established under case number EB-2010-0008. The OEB's June 2011 decision and order authorized the variance account to be in effect for the period from March 1, 2011 to December 31, 2012. The OEB expects OPG to file an independent actuary's report in relation to the amounts recorded in the variance account, including:

1. a description of the methodology followed and the assumptions made by management in determining actual pension and OPEB costs; and
2. a confirmation that this methodology is consistent with that outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008.

The forecast pension and OPEB costs for the years ending December 31, 2011 and 2012 reflected in the regulated prices established under case number EB-2010-0008 represent the portion of OPG's total forecast pension and OPEB costs for those years attributable to its nuclear and regulated hydroelectric businesses. These forecast costs were based on calculations prepared by the prior actuary, Mercer (Canada) Limited.

Results for Year 2012

This report confirms that OPG's total actual pension and OPEB costs for the year ended December 31, 2012 as determined in accordance with US GAAP and Canadian GAAP are as follows:

(in Canadian $ 000's)	US GAAP	Canadian GAAP
RPP	$ 356,365	$ 356,365
SPP	$ 25,594	$ 25,594
OPRB	$ 227,188	$ 227,188
LTD	$ 31,313	$ 23,885
Total	$ 640,460	$ 633,032

Further details of the above OPG-wide actual costs, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB, are provided in Schedules 1 and 2 to this report. The above table and Schedules 1 and 2 do not include amounts recognized under US GAAP in accumulated other comprehensive income during 2012 for actuarial gains or losses and past service costs arising during 2012 in respect of RPP, SPP or OPRB.

The balance of the Pension and OPEB Cost Variance Account calculated and recorded by OPG as at December 31, 2012 is $324 million, as reported in the audited schedule of regulatory balances as at December 31, 2012, dated February 6, 2013, prepared by OPG for filing with the OEB.

The pension and OPEB cost variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2012 was calculated by OPG by comparing the portion of the above actual OPG-wide costs under Canadian GAAP attributed to OPG's nuclear and regulated hydroelectric businesses for the year ended December 31, 2012, as well as the portion of such actual OPG-wide costs for the ten-month period ended December 31, 2011, to the forecast of such costs included in the regulated prices established under case number EB-2010-0008. Aon Hewitt previously reported on the 2011 actual OPG-wide costs for pension and OPEB under Canadian GAAP in support of the December 31, 2011 balance of the Pension and OPEB Cost Variance Account in the report dated June 2012 and titled "Report on the CICA 3461 (CGAAP) Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations" (the "2011 Variance Account Report"). This 2011 Variance Account Report has been filed by OPG with the OEB under case number EB-2012-0002.

Actuarial Methods and Assumptions

Aon Hewitt confirms that the above US and Canadian GAAP OPG-wide costs for the year ended December 31, 2012 were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under Canadian GAAP is consistent with the methodology as outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008 and used to determine the forecast pension and OPEB costs reflected in the regulated prices established by the OEB in that proceeding. This methodology is also consistent with that used to determine the actual OPG-wide Canadian GAAP costs for the year ended December 31, 2011 outlined in the 2011 Variance Account Report. The methodology under US GAAP is consistent with that outlined and used to determine the information for OPG's post employment benefit plans for 2011 under US GAAP provided in Aon Hewitt's report dated April 2012 and titled "Transition Report for US GAAP and Canadian GAAP for Pension, Non-Pension Post Retirement and Post-Employment Benefit Plans". This report has been filed by OPG with the OEB under case number EB-2012-0002.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;

- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs based on membership data as of December 31, 2011 contained in the Reports, and as of December 31, 2012 as follows:

Summary of Disabled Members as at December 31, 2012 for LTD Valuation

	Number of Members	Average Age	Average Earnings	Average LTD Monthly Benefit	Number of Members with Health and Dental Coverage
Total	396	54.4	$80,955	$4,122	376

- The discount rates have been determined in accordance with US GAAP and Canadian GAAP (i.e., CICA 3461). The discount rates have been set with reference to those representative of AA corporate bond yields having a duration similar to the liabilities of the plans. The December 31, 2011 discount rates were 5.10% per annum for determining the 2012 RPP and SPP cost, 5.20% per annum for determining the 2012 OPRB cost, and 4.00% per annum for determining the 2012 LTD cost. The 2012 LTD cost under US GAAP is also based on a discount rate of 3.50% per annum as at December 31, 2012, which was used to determine the LTD benefit obligation as at December 31, 2012;

- A building block approach was used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using target asset allocations, via a building block approach with proper consideration of diversification and rebalancing. The expected rate of return on assets of 6.50% per annum determined using the above approach was used for determining the 2012 RPP cost;

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with independent actuaries and as set out in the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 3.00% per annum (plus Promotion, Progression, Merit), respectively;

- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP and Canadian GAAP for non-routine events during the year (none during 2012);

- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP and Canadian GAAP for non-routine events during the year (none during 2012);

- For LTD, under Canadian GAAP, the change in the obligation due to changes in economic assumptions is deferred and amortized, and the sum of the following is recognized immediately: (i) the change in the obligation at the end of the year compared to the obligation at the beginning of the year on the same economic basis and (ii) actual benefit payments. In addition, past service costs are also deferred and amortized. Under US GAAP, all actuarial gains and losses and past service costs in relation to LTD are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the obligation plus benefit payments;

- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years; and,

- Curtailments are recognized before settlements (none during 2012).

Schedule 1—Summary of 2012 US GAAP Results

The following table provides a summary of US GAAP results for 2012 for the post employment benefit plans sponsored by OPG. The 2012 net periodic pension/benefit cost for the period January 1, 2012 to December 31, 2012 is determined based on the balance sheet items at January 1, 2012 and reflects the finalization of 2012 cost.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2012				
Projected Benefit Obligation	$ (12,155,303)	$ (257,968)	$ (2,415,132)	$ (285,074)
Fair Value of Plan Assets	9,563,300	0	0	0
Net Asset (Liability) Recognized	$ (2,592,003)	$ (257,968)	$ (2,415,132)	$ (285,074)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2012				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 12,791	$ 0
Unrecognized Net Actuarial Loss (Gain)	3,768,869	76,149	649,506	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,768,869	$ 76,149	$ 662,297	$ 0
Components of Net Periodic Pension/Benefit Cost, January 1, 2012 to December 31, 2012				
Employer Current Service Cost	$ 261,771	$ 8,258	$ 66,626	$ 10,798
Interest Cost	615,869	13,275	127,368	10,762
Expected Return on Plan Assets	(665,076)	0	0	0
Amortization of Past Service Cost	0	0	1,857	0
Amortization of Net (Gain) Loss	143,801	4,061	31,337	9,753
Total Cost	$ 356,365	$ 25,594	$ 227,188	$ 31,313
2012 Actual Employer Pension Contributions / OPEB Payments	$ 370,000	$ 15,512	$ 56,583	$ 26,361

Schedule 2—Summary of 2012 Canadian GAAP Results

The following table provides a summary of Canadian GAAP results for 2012 for the post employment benefit plans sponsored by OPG. The 2012 net periodic pension/benefit cost for the period January 1, 2012 to December 31, 2012 is determined based on the balance sheet items at January 1, 2012 and reflects the finalization of 2012 cost.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Accrued Benefit Asset (Liability) as at January 1, 2012				
Accrued Benefit Obligation	$ (12,155,303)	$ (257,968)	$ (2,415,132)	$ (285,074)
Fair Value of Plan Assets	9,563,300	0	0	0
Excess (Deficit)	$ (2,592,003)	$ (257,968)	$ (2,415,132)	$ (285,074)
Unrecognized Past Service Costs (Credits)	0	0	12,791	1,587
Unrecognized Net Actuarial Loss (Gain)	3,768,869	76,149	649,506	49,812
Accrued Benefit Asset (Liability)	$ 1,176,866	$ (181,819)	$ (1,752,835)	$ (233,675)
Components of Net Periodic Pension/Benefit Cost, January 1, 2012 to December 31, 2012				
Employer Current Service Cost	$ 261,771	$ 8,258	$ 66,626	$ 10,798
Interest Cost	615,869	13,275	127,368	10,762
Expected Return on Plan Assets	(665,076)	0	0	0
Amortization of Past Service Cost	0	0	1,857	388
Amortization of Net (Gain) Loss	143,801	4,061	31,337	1,937
Total Cost	$ 356,365	$ 25,594	$ 227,188	$ 23,885
2012 Actual Employer Pension Contributions / OPEB Payments	$ 370,000	$ 15,512	$ 56,583	$ 26,361

Attachment 4
Year-End 2012 Derivative Valuation: Pre-Life Extension Period

Valuation Date	**Mon 31-Dec-2012**	**Bruce Embedded Derivative Valuation**			
Discount Rate	2.36%				
		2012	**2013**	**2014**	**Total**
Estimated CPI		2.38%	1.94%	2.05%	
Full Supplemental Rent		125,861,581	128,303,296	130,933,513	385,098,390
Reduced Supplemental Rent		48,000,000	48,000,000	48,000,000	144,000,000
Full Rent Rebate		77,861,581	80,303,296	82,933,513	241,098,390
PV of Full Rent Rebate		77,861,581	78,451,833	79,153,388	235,466,802
Exercise Probability		100.00%	96.02%	86.02%	
PV of Expected Rebate		**77,861,581**	**75,328,820**	**68,089,700**	**221,280,101**
Average HOEP to Date		22.80			
Daily Volatility			1.09%	1.09%	
Expected Annual Average HOEP			**22.48**	**23.72**	

Amount of Full Supplemental Rent represents a best estimate of supplemental rent payable for Bruce B units before the rent rebate.

As the Average HOEP for 2012 was below $30/MWh, the PV of Expected Rebate for 2012 represents the amount of the unconditional rent rebate payable by OPG for that year with respect to Bruce B units.

Attachment 4
Year-End 2012 Derivative Valuation: Life Extension

Valuation Date	**Mon 31-Dec-2012**			**Bruce Embedded Derivative Valuation**		
Discount Rate	2.36%			**— Life Extension —**		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Estimated CPI	1.99%	1.94%	1.97%	1.98%	2.00%	
Full Supplemental Rent	133,539,090	136,129,749	138,811,505	141,559,972	144,391,172	694,431,488
Reduced Supplemental Rent	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	240,000,000
Full Rent Rebate	85,539,090	88,129,749	90,811,505	93,559,972	96,391,172	454,431,488
PV of Full Rent Rebate	79,757,916	80,278,902	80,814,536	81,340,797	81,870,100	404,062,250
Exercise Probability	78.04%	67.48%	63.22%	54.42%	45.13%	
PV of Expected Rebate	**62,246,021**	**54,175,757**	**51,094,317**	**44,266,247**	**36,949,224**	**248,731,566**
Average HOEP to Date						
Daily Volatility	1.09%	1.09%	1.09%	1.09%	1.09%	
Expected Annual Average HOEP	**25.58**	**27.67**	**28.46**	**30.08**	**31.85**	

Amount of Full Supplemental Rent represents a best estimate of supplemental rent payable for Bruce B units before the rent rebate.

ATTACHMENT 5
PARAMETER VALUES FOR YEAR-END 2012 DERIVATIVE VALUATION

The parameter values that were used in the year-end 2012 valuation of the derivative embedded in the Bruce Lease agreement (provided in Attachment 4) are as follows:

Valuation Date Mon 31-Dec-2012				Bruce Embedded Derivative Valuation Parameter Values			
	Forward Price F	Nr Trading Days NTD	Daily Volatility	sigma	lambda	Strike Price K	Prob of Exercise EB
2013	$ 25.623	250.0	0.010945	0.173057	0.130674	$ 30.00	96.02%
2014	$ 28.291	500.0	0.010945	0.244740	0.176029	$ 30.00	86.02%

Valuation Date Mon 31-Dec-2012				Bruce Embedded Derivative Valuation Parameter Values		Life Extension	
	Forward Price F	Nr Trading Days NTD	Daily Volatility	sigma	lambda	Strike Price K	Prob of Exercise EB
2015	$ 30.503	500.0	0.010945	0.244740	0.176029	$ 30.00	78.04%
2016	$ 32.991	500.0	0.010945	0.244740	0.176029	$ 30.00	67.48%
2017	$ 33.937	500.0	0.010945	0.244740	0.176029	$ 30.00	63.22%
2018	$ 35.874	500.0	0.010945	0.244740	0.176029	$ 30.00	54.42%
2019	$ 37.982	500.0	0.010945	0.244740	0.176029	$ 30.00	45.13%

ATTACHMENT 6
2012 JOURNAL ENTRIES FOR EMBEDDED DERIVATIVE LIABILITY

The journal entries recorded by OPG during 2012 in respect of the impact of the embedded derivative on supplemental rent revenue and the partial supplemental rent rebate to Bruce Power L.P. are summarized below. These entries represent an update to, and are presented in the same format as, the projected entries provided in response to interrogatory L-1-1 Staff-09 (b).

***Entry #1-2012** – Net amounts recognized in the derivative liability during 2012 for changes in the present value of the probability-weighted expectation of the reduction in the supplemental rent payment for 2012. This entry, combined with entries in previous years, results in OPG reflecting a liability for the full amount of the 2012 rent rebate.*

DR		Supplemental Rent Revenue		$11M	
	CR		Derivative Liability		$11M

***Entry #2-2012** – Net amounts recognized in the derivative liability during 2012 for changes in the present value of probability-weighted expectations of reductions in supplemental rent payments for the remaining accounting service life (beyond 2012) of the Bruce B station in effect prior to December 31, 2012, i.e., for 2013-2014.*

DR		Supplemental Rent Revenue		$24M	
	CR		Derivative Liability		$24M

The net effect of these two entries is a reduction to supplemental rent revenue of $35M recognized during 2012.

***Entry #3-2012** – Amount recognized in the derivative liability at December 31, 2012 as a result of the extension of the average accounting service life of the Bruce B station from 2014 to 2019 based on the present value of the probability-weighted expectations of reductions in supplemental rent payments for the additional period of 2015 - 2019.*

DR		Supplemental Rent Revenue		$249M	
	CR		Derivative Liability		$249M

***Entry #4-2012** – Realization of the reduction in the supplemental rent payment for 2012 upon having determined that Average HOEP fell below $30/MWh in 2012.*

DR		Derivative Liability		$78M	
	CR		Accrued Payable [1]		$78M

[1] As the actual physical cash disbursement for the 2012 rebate occurs in 2013, the amount is recorded in 2012 as an increase (credit) to an accrued payable liability rather than a decrease (credit) to cash.

The above journal entries are presented in Chart 1 below in the form of increases and decreases to the line items on OPG’s 2012 balance sheet and income statement in accordance with both CGAAP and USGAAP.

Chart 1
2012 Financial Statement Impact of Embedded Derivative

Actual 2012			
Balance Sheet		**Income Statement**	
Accrued Payable	+78M	Revenue	-284M[2]
Derivative Liability	+206M[1]		
Retained Earnings	-284M		

Note 1: Sum of $11M (entry #1-2012), $24M (entry #2-2012) and $249M (entry #3-2012), less $78M (entry #4-2012)

Note 2: Sum of $11M (entry #1-2012), $24M (entry #2-2012) and $249M (entry #3-2012)

Numbers may not add due to rounding.

Table 1
(Updated version of Ex. H1-1-1 Table 1)
Summary of Deferral and Variance Accounts
Closing Account Balances - 2009 to 2012 Amounts ($M)

Line No.	Account	Year End Balance 2009[1]	Approved Year End Balance 2010[2]	Year End Balance 2011	Year End Balance 2012	Projected Year End 2012 Balance from Ex. H1-1-1 Table 1
		(a)	(b)	(c)	(d)	(e)
	Regulated Hydroelectric:					
1	**Hydroelectric Water Conditions Variance**	(55.3)	(70.2)	(41.4)	17.1	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(16.0)	(9.4)	10.6	34.0	32.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	(1.4)	(2.4)	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.5	4.1	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(0.3)	(8.1)	(6.8)	(2.5)	(2.6)
6	**Tax Loss Variance - Hydroelectric**	47.1	78.8	68.0	48.2	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	0.0	(0.7)	1.1	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	4.0	15.1	16.7
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	2.8	2.7
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.2)	(2.3)	(1.2)	0.0	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	0.0	(7.9)	(5.9)	(3.9)	(3.4)
12	**Total**	(26.6)	(19.1)	25.6	113.8	109.1
	Nuclear:					
13	**Pickering A Return To Service (PARTS) Deferral**	81.8	33.2	0.0	0.0	0.0
14	**Nuclear Liability Deferral**	86.2	39.2	21.8	208.0	181.7
15	**Nuclear Development Variance**	(55.6)	(110.8)	(55.1)	30.2	37.2
16	**Transmission Outages and Restrictions Variance**	0.7	0.1	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	(0.6)	0.6	0.8	1.7	1.4
18	**Capacity Refurbishment Variance - Nuclear**	(0.3)	(8.5)	0.2	13.1	13.3
19	**Nuclear Fuel Cost Variance**	(15.7)	6.4	9.4	0.0	0.0
20	**Bruce Lease Net Revenues Variance**	324.5	249.4	196.0	310.5	368.2
21	**Income and Other Taxes Variance - Nuclear**	(12.1)	(31.6)	(42.9)	(32.5)	(31.6)
22	**Tax Loss Variance - Nuclear**	247.2	413.7	356.8	253.3	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	92.4	309.1	333.1
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	60.3	56.7
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	6.6	3.7	0.0	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	10.7	20.8	1.5	6.9	5.1
27	**Total**	673.3	619.0	584.6	1,160.6	1,218.3
28	**Grand Total**	646.7	600.0	610.2	1,274.4	1,327.4

Notes:
1 Year end balances as of December 31, 2009 as per EB-2010-0008 Ex. H1-1-2 filed October 8, 2010.
2 Year end balances as of December 31, 2010 approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.

Table 1a
(Updated version of Ex. H1-1-1 Table 1a)
Deferral and Variance Accounts
Continuity of Account Balances - 2010 to February 2011 ($M)

Line No.	Account	Approved Year End Balance 2010[1]	January - February 2011				(a)+(b)+(c)+(d)+(e) Balance February 28, 2011
			Transactions	Amortization	Interest	Transfers	
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(70.2)	1.0	0.0	(0.2)	0.0	(69.4)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(9.4)	1.6	0.0	0.0	0.0	(7.8)
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.0	0.0	0.0	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(8.1)	(2.2)	0.0	0.0	0.0	(10.3)
6	**Tax Loss Variance - Hydroelectric**	78.8	5.2	0.0	0.2	0.0	84.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	(0.7)	0.0	0.0	0.0	(0.7)
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.3)	0.0	0.0	0.0	0.0	(2.3)
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(7.9)	(1.2)	0.0	0.0	0.0	(9.2)
12	**Total**	(19.1)	3.6	0.0	0.0	0.0	(15.4)
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**	33.2	0.0	(8.2)	0.1	0.0	25.1
14	**Nuclear Liability Deferral**	39.2	0.0	0.0	0.1	0.0	39.3
15	**Nuclear Development Variance**	(110.8)	(7.9)	0.0	(0.3)	0.0	(119.0)
16	**Transmission Outages and Restrictions Variance**	0.1	0.0	0.0	0.0	0.0	0.1
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.6	0.1	0.0	0.0	0.0	0.6
18	**Capacity Refurbishment Variance - Nuclear**	(8.5)	0.5	0.0	(0.0)	0.0	(8.0)
19	**Nuclear Fuel Cost Variance**	6.4	5.8	0.0	0.0	0.0	12.2
20	**Bruce Lease Net Revenues Variance**	249.4	(13.6)	0.0	0.6	0.0	236.4
21	**Income and Other Taxes Variance - Nuclear**	(31.6)	(8.1)	0.0	(0.1)	0.0	(39.7)
22	**Tax Loss Variance - Nuclear**	413.7	27.3	0.0	1.0	0.0	441.9
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	0.0	0.0	0.0	0.0	6.6
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	20.8	(9.4)	0.0	0.0	0.0	11.4
27	**Total**	619.0	(5.3)	(8.2)	1.4	0.0	607.0
28	**Grand Total**	600.0	(1.7)	(8.2)	1.4	0.0	591.5

Notes:
1 Year end balances as of December 31, 2010 approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.

Table 1b
(Updated version of Ex. H1-1-1 Table 1b)
Deferral and Variance Accounts
Continuity of Account Balances - March to December 2011 ($M)

Line No.	Account	Balance February 28, 2011	March - December 2011 Transactions	Amortization[1]	Interest	Transfers	(a)+(b)+(c)+(d)+(e) Year End Balance 2011
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(69.4)	(3.2)	31.9	(0.7)	0.0	(41.4)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(7.8)	14.1	4.3	0.0	0.0	10.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	(1.4)	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.5	0.0	0.0	0.0	0.5
5	**Income and Other Taxes Variance - Hydroelectric**	(10.3)	(0.1)	3.7	(0.1)	0.0	(6.8)
6	**Tax Loss Variance - Hydroelectric**	84.2	0.0	(17.1)	0.9	0.0	68.0
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	0.0	0.0	0.0	0.0	(0.7)
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	4.0	0.0	0.0	0.0	4.0
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.3)	0.0	1.0	0.0	0.0	(1.2)
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(9.2)	(0.2)	3.6	(0.1)	0.0	(5.9)
12	**Total**	(15.4)	13.7	27.3	0.0	0.0	25.6
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral[2]**	25.1	0.0	(33.2)	0.1	8.0	0.0
14	**Nuclear Liability Deferral**	39.3	0.0	(17.8)	0.3	0.0	21.8
15	**Nuclear Development Variance**	(119.0)	14.5	50.4	(1.0)	0.0	(55.1)
16	**Transmission Outages and Restrictions Variance**	0.1	0.0	(0.0)	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.6	0.5	(0.3)	0.0	0.0	0.8
18	**Capacity Refurbishment Variance - Nuclear**	(8.0)	4.4	3.9	(0.0)	0.0	0.2
19	**Nuclear Fuel Cost Variance**	12.2	0.0	(2.9)	0.1	0.0	9.4
20	**Bruce Lease Net Revenues Variance**	236.4	70.4	(113.4)	2.5	0.0	196.0
21	**Income and Other Taxes Variance - Nuclear**	(39.7)	(17.1)	14.3	(0.4)	0.0	(42.9)
22	**Tax Loss Variance - Nuclear**	441.9	0.0	(89.9)	4.8	0.0	356.8
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	91.9	0.0	0.5	0.0	92.4
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	0.0	(3.0)	0.1	0.0	3.7
26	**Nuclear Deferral and Variance Over/Under Recovery Variance[2]**	11.4	7.4	(9.5)	0.2	(8.0)	1.5
27	**Total**	607.0	171.9	(201.4)	7.2	0.0	584.6
28	**Grand Total**	591.5	185.5	(174.0)	7.2	0.0	610.2

Notes:
1 Amortization is based on 2010 year-end balances and recovery periods approved in the EB-2010-0008 Payment Amounts Order.
2 In accordance with the EB-2010-0008 Payment Amounts Order, the PARTS Deferral Account was terminated on December 31, 2011, and the remaining balance of $8.0M was transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

Numbers may not add due to rounding.

Table 1c
(Updated version of Ex. H1-1-1 Table 1c)
Deferral and Variance Accounts
Continuity of Account Balances - 2011 to 2012 ($M)

Line No.	Account	Year End Balance 2011	Actual 2012				(a)+(b)+(c)+(d)+(e) Year End Balance 2012
			Transactions	Amortization[1]	Interest	Transfers	
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(41.4)	20.4	38.3	(0.2)	0.0	17.1
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	10.6	18.1	5.1	0.3	0.0	34.0
3	**Hydroelectric Incentive Mechanism Variance**	(1.4)	(0.9)	0.0	(0.0)	0.0	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.5	3.6	0.0	0.0	0.0	4.1
5	**Income and Other Taxes Variance - Hydroelectric**	(6.8)	(0.1)	4.4	(0.1)	0.0	(2.5)
6	**Tax Loss Variance - Hydroelectric**	68.0	0.0	(20.6)	0.8	0.0	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	1.9	0.0	0.0	0.0	1.1
8	**Pension and OPEB Cost Variance - Hydroelectric**	4.0	11.0	0.0	0.1	0.0	15.1
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	2.8	0.0	0.0	0.0	2.8
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance[2]**	(1.2)	0.0	1.2	0.0	0.0	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance[2]**	(5.9)	(2.2)	4.3	(0.1)	0.0	(3.9)
12	**Total**	25.6	54.5	32.8	0.9	0.0	113.8
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**	0.0	0.0	0.0	0.0	0.0	0.0
14	**Nuclear Liability Deferral**	21.8	206.2	(21.4)	1.4	0.0	208.0
15	**Nuclear Development Variance**	(55.1)	25.2	60.4	(0.3)	0.0	30.2
16	**Transmission Outages and Restrictions Variance[3]**	0.0	0.0	(0.0)	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.8	1.1	(0.3)	0.0	0.0	1.7
18	**Capacity Refurbishment Variance - Nuclear**	0.2	8.2	4.6	0.1	0.0	13.1
19	**Nuclear Fuel Cost Variance[3]**	9.4	0.0	(3.5)	0.1	(6.0)	0.0
20	**Bruce Lease Net Revenues Variance**	196.0	248.2	(136.0)	2.4	0.0	310.5
21	**Income and Other Taxes Variance - Nuclear**	(42.9)	(6.3)	17.2	(0.6)	0.0	(32.5)
22	**Tax Loss Variance - Nuclear**	356.8	0.0	(107.9)	4.4	0.0	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	92.4	214.0	0.0	2.8	0.0	309.1
24	**Impact for USGAAP Deferral - Nuclear**	0.0	59.4	0.0	0.8	0.0	60.3
25	**Nuclear Interim Period Shortfall (Rider B) Variance[3]**	3.7	0.0	(3.6)	0.0	(0.1)	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance[3]**	1.5	10.7	(11.4)	0.0	6.1	6.9
27	**Total**	584.6	766.6	(201.8)	11.1	0.0	1,160.6
28	**Grand Total**	610.2	821.1	(169.0)	12.1	0.0	1,274.4

Notes:

1 Amortization is based on 2010 year-end balances and recovery periods approved in the EB-2010-0008 Payment Amounts Order.

2 In accordance with the EB-2010-0008 Payment Amounts Order, the Hydroelectric Interim Period Shortfall (Rider D) Variance Account was terminated on December 31, 2012, and the remaining balance of less than $0.1M was transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account.

3 In accordance with the EB-2010-0008 Payment Amounts Order, the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account and the Nuclear Interim Period Shortfall (Rider B) Variance Account were terminated on December 31, 2012, and the remaining balances of nil, $6.0M and $0.1M respectively were transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

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 - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Actual 2012
		(a)	(b)	(c)	(d)
1	**Forecast Production - EB-2009-0174 / EB-2010-0008[1] (GWh)**	2,769	15,594	18,363	18,573
2	**Calculated Actual Production (GWh)**	2,736	15,748	18,484	17,638
3	**Difference (GWh)** (line 1 - line 2)	33	(154)	(121)	935
4	**Revenue Impact @ $36.66/MWh for Jan-Feb 2011 and $35.78/MWh for Mar-Dec 2011 and 2012 ($M)**	1.2	(5.5)	(4.3)	33.5
5	**GRC/Water Rental Costs ($M)**	(0.2)	2.3	2.1	(13.0)
6	**Addition to Variance Account ($M)** (line 4 + line 5)	1.0	(3.2)	(2.2)	20.4

Notes:

1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March 2011 to December 2012 forecast has been determined based on amounts reflected in the payment amounts approved in EB-2010-0008.

Numbers may not add due to rounding.

Table 3
(Updated version of Ex. H1-1-1 Table 3)
Ancillary Services Net Revenue Variance Account - Hydroelectric
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Actual 2012
		(a)	(b)	(c)	(d)
1	**Forecast Revenue**[1]	5.5	32.4	37.9	38.9
2	**Actual Revenue**	3.9	18.3	22.2	20.8
3	**Addition to Variance Account** (line 1 - line 2)	1.6	14.1	15.7	18.1

Notes:

1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March to December 2011 and 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, Appendix F, page 3, prorated as follows:

Table to Note 1 - Proration of Forecast Revenue Amounts ($M)

Line No.		
		(a)
1a	Forecast Revenue from EB-2010-0008	77.8
2a	Mar-Dec 2011 Amount ((line 1a / 24 months) x 10 months)	32.4
3a	2012 Amount ((line 1a / 24 months) x 12 months)	38.9

Numbers may not add due to rounding.

Table 4
(Updated version of Ex. H1-1-1 Table 4)
Income and Other Taxes Variance Account[1]
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Actual 2012
		(a)	(b)	(c)
	Entry (i) Scientific Research and Experimental Development ("SR&ED") Expenditures and Investment Tax Credits ("ITCs") for April 1, 2008 to February 28, 2011 Recognized after December 31, 2010			
1	**Actual SR&ED ITCs @50%[2]**	(2.0)	0.0	0.0
2	**Actual Tax Benefit of SR&ED Capital Expenditures @100%[2]**	(5.1)	0.0	(0.9)
3	**Actual Tax on ITCs of Prior Periods @50%[2]**	0.7	1.5	(1.0)
4	**Addition to Variance Account** (line 1 + line 2 + line 3)	(6.4)	1.5	(1.9)
	Entry (ii) Increase of SR&ED ITCs Recognition Percentage from 50% to 75% for April 1, 2008 to December 31, 2012[3]			
	For April 1, 2008 to December 31, 2010 (recognized before January 1, 2011):			
5	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the December 31, 2010 Approved Balance of the Income and Other Taxes ("I&OT") Variance Account @ 50%**		(26.0)	
6	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 5 x 3/2)		(39.0)	
7	**Addition to Variance Account** (line 6 - line 5)	0.0	(13.0)	0.0
	For April 1, 2008 to February 28, 2011 (recognized after December 31, 2010):			
8	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the I&OT Variance Account after December 31, 2010 @ 50%** (line 1 + line 3)	(1.3)	1.5	(1.0)
9	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 8 x 3/2)	(1.9)	2.3	(1.5)
10	**Addition to Variance Account** (line 9 - line 8)	(0.6)	0.8	(0.5)
	For March 1, 2011 to December 31, 2012:			
11	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @50% - EB-2010-0008[4]**		(5.5)	(6.6)
12	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 11 x 3/2)		(8.2)	(9.8)
13	**Addition to Variance Account** (line 12 - line 11)	0.0	(2.7)	(3.3)
14	**Total Addition to Variance Account - SR&ED Expenditures and ITCs** (line 4 + line 7 + line 10 + line 13)	(7.0)	(13.5)	(5.7)
	Entry (iii) Income Tax Variance Due to Income Tax Rate Reduction			
15	**Forecast Regulatory Taxable Income - EB-2009-0174[5]**	120.6		
16	**Income Tax Rate Differential[5]** (26.50% - 31.21%)	-4.71%		
17	**Total Addition to Variance Account - Income Tax Rate Reduction** (line 15 x line 16 x 2/12)	(0.9)	0.0	0.0
	Entry (iv) Income Tax Variance Due to Unburned Nuclear Fuel Adjustment			
18	**Actual Unburned Nuclear Fuel Adjustment**	14.1		
19	**Income Tax Rate**	26.50%		
20	**Total Addition to Variance Account - Unburned Nuclear Fuel Adjustment** (line 18 x line 19 x 2/12)	0.6	0.0	0.0
	Entry (v) Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment			
	For April 1, 2008 to December 31, 2010:			
21	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		7.5	
22	**Additional Capital Cost Allowance**		17.0	
23	**Impact on Taxable Income** (line 21 - line 22)		(9.5)	
24	**Addition to Variance Account[6]** (line 23 x actual income tax rate applicable to each period)	0.0	(2.8)	0.0
	For January 1, 2011 to December 31, 2012:			
25	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**	0.1	0.7	1.0
26	**Additional Capital Cost Allowance**	0.8	4.0	4.0
27	**Impact on Taxable Income** (line 25 - line 26)	(0.7)	(3.3)	(3.0)
28	**Income Tax Rate**	26.50%	26.50%	25.0%
29	**Addition to Variance Account** (line 27 x line 28)	(0.2)	(0.9)	(0.8)
30	**Total Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (lines 24 + 29)	(0.2)	(3.7)	(0.8)
	Entry (vi) Capital Tax Variance Due to Capital Tax Elimination			
31	**Forecast Capital Tax - EB-2009-0174[5]**	16.5		
32	**Actual Capital Tax (eliminated effective July 1, 2010)**	0.0		
33	**Total Addition to Variance Account - Capital Tax Elimination** (line 32- line 31) x 2/12	(2.8)	0.0	0.0
34	**Grand Total Addition to Variance Account** (line 14 + line 17 + line 20 + line 30 + line 33)	(10.3)	(17.2)	(6.4)

Notes:
1 The six entries into the account for 2011 and 2012 are discussed in Ex. H1-1-1 Section 4.2.
2 Amounts in col. (a) relating to Jan-Feb 2011 have been determined as 2/12 of the actual annual 2011 amounts.
Amounts in col. (c) include the tax on ITCs recorded in 2011, which are taxed in 2012, and adjustments, based on the 2011 tax returns filed in 2012, to the variances recorded in 2011. Amounts in cols. (b) and (c) also include offsetting inter-period financial statement reconciliation adjustments of $1.5M and ($1.5M), respectively, which do not impact the total transactions in the account over the 2011-2012 period.
3 The increase in the percentage of SR&ED ITCs recognized for accounting purposes from 50% to 75% occurred in 2011.
4 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 4 - 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 Investment Tax Credits of Prior Periods (from EB-2010-0008, Ex. F4-2-1 Table 5, line 11) x tax rate (26.50% for 2011 and 25.00% for 2012)	2.3	2.2	4.5
4a	Total Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods from EB-2010-0008 (lines 1a + 2a +3a)	(6.5)	(6.6)	(13.1)
5a	Mar-Dec 2011 Amount ((line 4a, col. (c) / 24 months) x 10 months)	(5.5)		
6a	2012 Amount ((line 4a, col. (c) / 24 months) x 12 months)		(6.6)	

5 The annual forecast amounts for 2011 and the forecast income tax rate of 31.21% have been determined in accordance with EB-2009-0174 and are the same as those used to calculate the 2010 addition to the I&OT Variance Account, which was approved for recovery in EB-2010-0008.
6 The following actual tax rates are applied to amounts for the respective years included in line 23: 31.50% for 2008; 31.00% for 2009; 29.00% for 2010.

Numbers may not add due to rounding.

Table 5
(Updated version of Ex. H1-1-1 Table 5)
Pension and OPEB Cost Variance Account [1]
Summary of Account Transactions - March to December 2011 and 2012 ($M)

Line No.	Particulars	Mar - Dec 2011 Hydroelectric	Mar - Dec 2011 Nuclear	Mar - Dec 2011 Total	Actual 2012 Hydroelectric	Actual 2012 Nuclear	Actual 2012 Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Pension Costs - EB-2010-0008** [2]	5.8	115.3	121.1	7.0	138.4	145.4
2	**Forecast OPEB Costs - EB-2010-0008** [2]	6.8	135.8	142.6	8.2	163.0	171.2
3	**Total Forecast Pension and OPEB Costs**	12.6	251.2	263.8	15.1	301.4	316.5
4	**Actual Pension Costs** [3,4]	7.8	162.2	170.0	13.8	272.3	286.1
5	**Actual OPEB Costs** [3,4]	7.7	160.3	168.1	10.7	211.4	222.1
6	**Total Actual Pension and OPEB Costs**	15.6	322.5	338.1	24.5	483.8	508.3
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)	2.0	46.8	48.9	6.8	133.9	140.8
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)	0.9	24.5	25.5	2.6	48.4	51.0
9	**Addition to Variance Account - Regulatory Tax Impact** [5]	1.0	20.5	21.5	1.6	31.6	33.2
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)	4.0	91.9	95.9	11.0	214.0	225.0

Notes:

1 All cost amounts are presented on a CGAAP basis. The variance account is discussed in Ex. H2-1-3 and Ex. H1-1-2.

2 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 2 - Proration of Forecast Costs ($M)

Line No.		Hydroelectric Pension Costs	Nuclear Pension Costs	Hydroelectric OPEB Costs	Nuclear OPEB Costs
		(a)	(b)	(c)	(d)
1a	2011 Full Year Forecast Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	5.8	114.0	8.0	159.3
2a	2012 Full Year Forecast Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	8.1	162.8	8.3	166.7
3a	Total Forecast Costs from EB-2010-0008	13.9	276.8	16.3	326.0
4a	Mar-Dec 2011 Amount ((line 3a / 24 months) x 10 months)	5.8	115.3	6.8	135.8
5a	2012 Amount ((line 3a / 24 months) x 12 months)	7.0	138.4	8.2	163.0

3 Actual amounts for 2011 represent 10/12 of the actual full year 2011 amounts and are found in the chart at page 5 of Ex. H2-1-3, Attachment 1.
Amounts for full year 2011 are as follows for regulated hydroelectric and nuclear, respectively: $9.4M and $194.6M for pension and $9.3M and $192.4M for OPEB.
These amounts represent the regulated portion of OPG's total actual pension and OPEB costs provided at pages 3 and 5 of Ex. H2-1-3, Attachment 2.

4 Actual amounts for 2012 represent the regulated portion of OPG's total pension and OPEB costs provided at pages 5 and 10 of Ex. H1-1-2, Attachment 3.

5 From Ex. H1-1-2 Table 5a, line 8.

Numbers may not add due to rounding.

Table 5a
(Updated version of Ex. H1-1-1 Table 5a)
Pension and OPEB Cost Variance Account
Calculation of Tax Impact - March to December 2011 and 2012 ($M)

Line		**Mar - Dec 2011**			**Actual 2012**		
No.	**Particulars**	**Hydroelectric**	**Nuclear**	**Total**	**Hydroelectric**	**Nuclear**	**Total**
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Regulatory Income Tax Impact**[1]	0.4	8.6	9.0	0.5	10.3	10.8
	Actual Additions to / Deductions from Regulatory Earnings Before Tax						
2	**Pension Costs** (Ex. H1-1-1 Table 5, line 4)	7.8	162.2	170.0	13.8	272.3	286.1
3	**OPEB Costs** (Ex. H1-1-1 Table 5, line 5)	7.7	160.3	168.1	10.7	211.4	222.1
4	**Less: Pension Plan Contributions**[2,3]	9.0	187.2	196.2	14.3	282.8	297.1
5	**Less: OPEB Payments**[2,3]	2.6	54.4	57.1	3.8	75.2	79.1
6	**Net Additions to Regulatory Earnings Before Tax**	3.9	80.9	84.8	6.4	125.8	132.1
7	**Actual Regulatory Income Tax Impact**[4] (line 6 x tax rate / (1 - tax rate))	1.4	29.2	30.6	2.1	41.9	44.0
8	**Addition to Variance Account - Regulatory Tax Impact** (line 7 - line 1)	1.0	20.5	21.5	1.6	31.6	33.2

Notes:

1 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 1 - Proration of Forecast Tax Impact ($M)

Line		2011			2012		
No.		Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Forecast Additions to / Deductions from Regulatory Earnings Before Tax						
1a	Full Year Pension Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	5.8	114.0	119.8	8.1	162.8	170.9
2a	Full Year OPEB Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	8.0	159.3	167.3	8.3	166.7	175.0
3a	Less: Full Year Pension Plan Contributions from EB-2010-0008, Ex. L-01-085	9.9	196.2	206.1	9.9	196.2	206.1
4a	Less: Full Year OPEB Payments from EB-2010-0008, Ex. L-01-085	3.6	71.9	75.5	3.9	76.9	80.8
5a	Net Additions to Regulatory Earnings Before Tax	0.3	5.2	5.5	2.6	56.4	59.0
6a	Forecast Regulatory Income Tax Impact (line 5a x tax rate / (1 - tax rate)) (note 4)	0.1	1.9	2.0	0.9	18.8	19.7
7a	Hydroelectric Mar-Dec 2011 Amount ((line 6a, cols. a+d / 24 months) x 10 months)			0.4			
8a	Nuclear Mar-Dec 2011 Amount ((line 6a, cols. b+e / 24 months) x 10 months)			8.6			
9a	Hydroelectric 2012 Amount ((line 6a, cols. a+d / 24 months) x 12 months)						0.5
10a	Nuclear 2012 Amount ((line 6a, cols. b+e / 24 months) x 12 months)						10.3

2 Actual amounts for 2011 represent 10/12 of the actual full year 2011 amounts and are found in the chart on page 7 of Ex. H2-1-3, Attachment 1.
Amounts for full year 2011 are as follows for regulated hydroelectric and nuclear, respectively: $10.8M and $224.6M for pension plan contributions and $3.2M and $65.3M for OPEB payments. These amounts represent the regulated portion of OPG's total actual amounts provided at page 5 of Ex. H2-1-3, Attachment 2.

3 Actual amounts for 2012 represent the regulated portion of OPG's total pension and OPEB cash amounts provided at pages 9 and 10 of Ex. H1-1-2, Attachment 3.

4 Tax rates for 2011 and 2012 are 26.50% and 25.00%, respectively.

Table 6
(Updated version of Ex. H1-1-1 Table 6)
Impact for USGAAP Deferral Account[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Actual 2012 Regulated Hydroelectric	Actual 2012 Nuclear	Actual 2012 Total
		(a)	(b)	(c)
	Transition Impacts Calculated as of January 1, 2011 (Actual):			
1	**Addition to Deferral Account for Previously Unrecognized Long-Term Disability Benefits Costs Recognized on Transition to USGAAP**[2]	1.4	30.0	31.4
	Transition Impacts Calculated for Year Ending December 31, 2011 (Actual):			
2	**Long-Term Disability Benefits Costs under USGAAP**[3]	1.6	33.8	35.4
3	**Long-Term Disability Benefits Costs under CGAAP**[3]	1.2	24.9	26.1
4	**Addition to Deferral Account** (line 2 - line 3)	0.4	8.9	9.3
	Implementation Impacts Calculated for Year Ending December 31, 2012 (Actual):			
5	**Long-Term Disability Benefits Costs under USGAAP**[4]	1.2	23.9	25.1
6	**Long-Term Disability Benefits Costs under CGAAP**[4]	0.9	18.3	19.2
7	**Addition to Deferral Account** (line 5 - line 6)	0.3	5.7	6.0
8	**Addition to Deferral Account for Regulatory Tax Impact** ((line 1 + line 4 + line 7) x 25.00% / (1 - 25.00%))	0.7	14.9	15.6
9	**Total Addition to Deferral Account** (line 1 + line 4 + line 7 + line 8)	2.8	59.4	62.2

Notes:

1. OPG's adoption of USGAAP and the resulting additions to the deferral account are discussed in Ex. A3-1-2 and Ex. H1-1-2.
2. Amounts represent the regulated portion of total OPG costs of $39.6M recognized on transition, as found on pages 5 and 10 of Ex. A3-1-2, Attachment 3.
3. Amounts represent the regulated portion of total OPG LTD benefits costs of $45.1M under USGAAP and $33.2M under CGAAP, as found on page 5 of Ex. A3-1-2, Attachment 3.
4. Amounts represent the regulated portion of total OPG LTD benefits costs of $23.9M under CGAAP and $31.3M under USGAAP, as found on page 5 of Ex. H1-1-2, Attachment 3.

Table 7
(Updated version of Ex. H1-1-1 Table 7)
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Actual 2012
		(a)	(b)	(c)
1	**Hydroelectric Forecast Production - EB-2010-0008[1] (TWh)**		16.7	19.8
2	**Hydroelectric Actual Production[2] (TWh)**	3.0	16.5	18.5
3	**Production Variance (TWh)** (line 1 - line 2)		0.1	1.4
4	**Hydroelectric Deferral and Variance Over/Under Recovery Rate[3,4] ($/MWh)**	0.42	(1.65)	(1.65)
5	**Addition to Variance Account ($M)**	(1.2)	(0.2)	(2.2)
	(Jan to Feb 2011, line 2 x line 4) (Mar-Dec 2011 and 2012, line 3 x line 4)			

Notes:

1 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, with the full year 2011 production adjusted for the months of January and February 2011.

2 Amount for full year 2011 is as reported in OPG’s Management’s Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

3 For January and February 2011, the recovery rate of $0.42/MWh = $13.4M / 32.01 TWh. $13.4M is the approved recovery amount for hydroelectric variance accounts per the EB-2007-0905 Payment Amounts Order, Appendix F. 32.01 TWh is the approved hydroelectric production forecast per the EB-2007-0905 Payment Amounts Order, Appendix E, Table 1, lines 4 and 8.

4 For March 2011 to December 2012, the approved hydroelectric payment rider per the EB-2010-0008 Payment Amounts Order, Appendix B, Table 1 is a credit of $1.65/MWh.

Numbers may not add due to rounding.

Table 8
(Updated version of Ex. H1-1-1 Table 8)
Pickering A Return To Service (PARTS) Deferral Account
Summary of 2011 Amortization

Line No.	Particulars	Monthly Amortization 2011	Total Amortization 2011
		(a)	(b)
1	**December 2007 Approved Balance ($M)**	183.8	
2	**Approved Recovery Period (Months)**	45	
3	**Monthly Amortization ($M)** (line 1 / line 2)	4.1	
4	**Jan-Feb 2011 Amortization[1] ($M)** (line 3 x 2 months)		8.2
5	**December 2010 Approved Balance ($M)**	33.2	
6	**Approved Recovery Period (Months)**	10	
7	**Monthly Amortization ($M)** (line 5 / line 6)	3.3	
8	**Mar-Dec 2011 Amortization[2] ($M)** (line 7 x 10 months)		33.2

Notes:
1 January to February 2011 amortization is based on EB-2007-0905 Payment Amounts Order.
2 March to December 2011 amortization is based on EB-2010-0008 Payment Amounts Order.

Table 9
(Updated version of Ex. H1-1-1 Table 9)
Nuclear Liability Deferral Account[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Actual 2012
		(a)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:	
1	**Depreciation Expense[2]**	98.2
	Return on Rate Base[3]	
2	**Average Asset Retirement Costs** (line 1a + ((line 1a - line 3a)) / 2	390.1
3	**Weighted Average Accretion Rate**	5.58%
4	**Return on Rate Base** (line 2 x line 3)	21.8
	Variable Expenses[4]	
5	**Used Fuel Storage and Disposal Variable Expenses**	25.3
6	**Low & Intermediate Level Waste Management Variable Expenses**	1.1
7	**Total Variable Expenses** (line 5 + line 6)	26.4
	Income Tax Impact	
8	**Forecast Contributions to Nuclear Segregated Funds - EB-2010-0008[5]**	140.4
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan[6]**	107.1
10	**Increase in Contributions to Nuclear Segregated Funds** (line 8 - line 9)	33.3
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)	179.6
12	**Income Tax Rate**	25.0%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))	59.9
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)	206.2

Notes:

1 The deferral account is discussed in Ex. H2-1-1 and Ex. H1-1-2.

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

Table to Note 2 - Depreciation Expense ($M)

Line No.		Pickering A	Pickering B	Darlington	(a)+(b)+(c) 2012
		(a)	(b)	(c)	(d)
1a	Asset Retirement Cost Adjustment[#]	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	Annual Depreciation (line 1a / line 2a x 12 for cols. (a) through (c))	36.8	64.0	(2.6)	98.2

\# Represents adjustment on December 31, 2011 arising from the current approved ONFA Reference Plan from Ex. H2-1-1 Table 3, line 7 and Ex. H1-1-2 Table 20, line 7.

\+ Represents the remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2011 (December 31, 2021 for Pickering A; September 30, 2014 for Pickering B; December 31, 2051 for Darlington).

3 Return on rate base is calculated using the weighted average accretion rate of 5.58%, per EB-2010-0008 Payment Amounts Order, App. F, pg. 5.

4 The variable expense component of the addition to the deferral account has been determined by multiplying the differences between: (i) the 2012 unit cost rates for each of the Used Fuel Storage and Disposal Programs ($/fuel bundle) and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs ($/m^3 of L&ILW) reflected in the payment amounts approved in EB-2010-0008 and (ii) the equivalent 2012 rates arising from the current approved ONFA Reference Plan and as reflected in the variable expenses in Ex. H1-1-2, Table 18, lines 4 and 5, col. (c), by the forecast number of used fuel bundles and L&ILW volumes reflected in EB-2010-0008 payment amounts.

5 Per the EB-2010-0008 Payment Amounts Order, App. A, Table 7, line 16, col. (c).

6 From Ex. H1-1-2 Table 18, line 16, col. (c).

Numbers may not add due to rounding.

Table 10
(Updated version of Ex. H1-1-1 Table 10)
Nuclear Development Variance Account[1]
Summary of Account Transactions - 2011 and 2012 ($M)

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

Notes:
1 Darlington New Nuclear costs are discussed in Ex. H2-2-1 and Ex. H1-1-2.
2 January and February 2011 forecast is 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.

Table 11
(Updated version of H1-1-1 Table 11)
Ancillary Services Net Revenue Variance Account - Nuclear
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Actual 2012
		(a)	(b)	(c)	(d)
1	**Forecast Revenue - EB-2009-0174 / EB-2010-0008**[1]	0.5	2.5	2.9	3.0
2	**Actual Revenue**	0.4	2.0	2.4	1.8
3	**Addition to Variance Account** (line 1 - line 2)	0.1	0.5	0.5	1.1

Notes:
1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March to December 2011 and 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, Appendix F, page 6, prorated as follows:

Table to Note 1 - Proration of Forecast Revenue Amounts ($M)

Line No.		
		(a)
1a	Forecast Revenue from EB-2010-0008 Payment Amounts Order	5.9
2a	Mar-Dec 2011 Amount ((line 1a / 24 months) x 10 months)	2.5
3a	2012 Amount ((line 1a / 24 months) x 12 months)	3.0

Numbers may not add due to rounding.

Table 12
(Updated version of H1-1-1 Table 12)
Capacity Refurbishment Variance Account - Nuclear[1]
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Actual 2012
		(a)	(b)	(c)	(d)
	Nuclear Forecast Costs - EB-2009-0174 / EB-2010-0008[2]:				
1	**Pickering B Refurbishment - Non-Capital Costs**	0.9	0.0	0.9	0.0
2	**Darlington Refurbishment - Non-Capital Costs**	3.6	4.3	8.0	5.2
3	**Fuel Channel Life Cycle Management Project - Non-Capital Costs**	0.0	4.9	4.9	5.9
4	**Pickering Continued Operations - Non-Capital Costs**	0.0	35.0	35.0	42.0
5	**Total** (lines 1 through 4)	4.5	44.2	48.7	53.1
	Nuclear Actual Costs:				
6	**Pickering B Refurbishment - Non-Capital Costs**	0.0	0.0	0.0	0.0
7	**Darlington Refurbishment - Non-Capital Costs**	0.7	1.9	2.6	2.8
8	**Fuel Channel Life Cycle Management Project - Non-Capital Costs**	0.6	9.5	10.1	11.3
9	**Pickering Continued Operations - Non-Capital Costs**	3.7	37.2	40.9	45.8
10	**Total** (lines 6 through 9)	5.0	48.6	53.6	59.9
	Addition to Variance Account - Nuclear:				
11	**Pickering B Refurbishment - Non-Capital Costs** (line 6 - line 1)	(0.9)	0.0	(0.9)	0.0
12	**Darlington Refurbishment - Non-Capital Costs** (line 7 - line 2)	(2.9)	(2.4)	(5.3)	(2.4)
13	**Fuel Channel Life Cycle Management Project - Non-Capital Costs** (line 8 - line 3)	0.6	4.6	5.2	5.4
14	**Pickering Continued Operations - Non-Capital Costs** (line 9 - line 4)	3.7	2.2	5.9	3.8
15	**Darlington Refurbishment - Capital Cost Variance for Future Recovery**	0.0	0.0	0.0	1.3
16	**Total Addition to Variance Account - Nuclear** (lines 11 through 15)	0.5	4.4	4.9	8.2

Notes:

1 The variance account is discussed in Ex. H2-2-1.

2 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. For line 1, the March 2011 to December 2012 forecast is nil, as there were no amounts reflected in the payment amounts approved in EB-2010-0008.
For lines 2, 3 and 4, March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 2 - Proration of Forecast Costs ($M)

Line No.		Darlington Refurbishment Non-Capital	Fuel Channel Life Cycle Mgmt Project	Pickering Continued Operations
		(a)	(b)	(c)
1a	2011 Full Year Forecast Costs from EB-2010-0008	5.9	7.7	45.7
2a	2012 Full Year Forecast Costs from EB-2010-0008	4.5	4.0	38.3
3a	Total Forecast Costs from EB-2010-0008	10.4	11.8	84.0
4a	Mar-Dec 2011 Amount ((line 3a / 24 months) x 10 months)	4.3	4.9	35.0
5a	2012 Amount ((line 3a / 24 months) x 12 months)	5.2	5.9	42.0

Table 13
(Updated version of Ex. H1-1-1 Table 13)
Nuclear Fuel Cost Variance Account
Summary of Account Transactions - January and February 2011

Line No.	Particulars	Jan - Feb 2011
		(a)
1	**Forecast Fuel Costs - EB-2009-0174[1] ($M)**	288.7
2	**Nuclear Forecast Production - EB-2009-0174[1] (TWh)**	88.2
3	**Forecast Fuel Rate ($/MWh)** (line 1 / line 2)	3.27
4	**Actual Fuel Costs ($M)**	34.6
5	**Nuclear Actual Production[2] (TWh)**	8.8
6	**Actual Fuel Rate ($/MWh)** (line 4 / line 5)	3.93
7	**Fuel Rate Variance ($/MWh)** (line 6 - line 3)	0.658
8	**Addition to Variance Account ($M)** (line 5 x line 7)	5.8

Notes:
1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order.
2 From Ex. H1-1-1 Table 14, col. (a), line 5 and Ex. H1-1-2 Table 14, col. (a), line 5.

Numbers may not add due to rounding.

Table 14
(Updated version of Ex. H1-1-1 Table 14)
Bruce Lease Net Revenues Variance Account[1]
Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Actual 2012
		(a)	(b)	(c)
1	**Actual Bruce Lease Net Revenues[2] ($M)**	32.7	35.5	(117.7)
2	**Forecast Bruce Lease Net Revenues - EB-2009-0174 / EB-2010-0008[3] ($M)**	191.9	271.1	271.1
3	**Nuclear Forecast Production - EB-2009-0174 / EB-2010-0008[3] (TWh)**	88.2	101.9	101.9
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)	2.18	2.66	2.66
5	**Actual Nuclear Production[4] (TWh)**	8.8	39.8	49.0
6	**Amount Credited to Customers ($M)** (line 4 x line 5)	19.1	105.9	130.4
7	**Addition to Variance Account ($M)** (line 6 - line 1)	(13.6)	70.4	248.2

Notes:

1 The variance account is discussed in Ex. H2-1-2 and Ex. H1-1-2.

2 From Ex. H1-1-2 Table 14a, line 22.

3 In accordance with the EB-2009-0174 Decision and Order, the forecast in col. (a) is for the EB-2007-0905 21-month test period of April 1, 2008 to December 31, 2009.
Forecasts in cols. (b) and (c) are for the 24-month test period of January 1, 2011 to December 31, 2012, as reflected in the EB-2010-0008 Payment Amounts Order: line 2 is from App. A, Table 2, line 20; line 3 is from App. C, Table 1, line 2.

4 Amount for full year 2011 is as reported in OPG's Management's Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

Numbers may not add due to rounding.

Filed: 2013-02-08
EB-2012-0002
Exhibit H1
Tab 1
Schedule 2
Table 14a

Table 14a
(Updated version of Ex. H1-1-1 Table 14a)
Bruce Lease Net Revenues Variance Account
Comparison of Bruce Lease Net Revenues - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011 Actual	Mar - Dec 2011 Actual	(a) + (b) 2011 Actual	2011 Board Approved (EB-2010-0008)	(c) - (d) Change	2012 Actual	2012 Board Approved (EB-2010-0008)	(f) - (g) Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Revenues:								
1	**Site Services (OPG to Bruce Power)**	0.0	1.1	1.1	0.6	0.5	0.7	0.5	0.2
2	**Low & Intermediate Level Waste Services**	3.0	11.7	14.6	13.6	1.0	5.8	12.4	(6.6)
3	**Cobalt-60**	0.0	0.5	0.5	0.5	(0.0)	0.4	0.5	(0.2)
4	**Total Services**	3.0	13.2	16.2	14.7	1.5	6.8	13.4	(6.6)
5	**Fixed (Base) Rent**	6.8	34.1	40.9	40.9	0.0	40.9	40.9	(0.0)
6	**Supplemental Rent**	26.5	134.5	161.0	186.7	(25.7)	(92.1)	202.3	(294.4)
7	**Amortization of Initial Deferred Rent**	2.0	10.1	12.1	12.1	0.0	12.1	12.1	(0.0)
8	**Total Rent**	35.3	178.7	214.0	239.8	(25.7)	(39.1)	255.3	(294.4)
9	**Total Revenues**	38.3	191.9	230.2	254.4	(24.2)	(32.3)	268.7	(301.0)
	Costs:								
10	**Depreciation**	6.0	27.2	33.2	34.5	(1.3)	78.9	34.5	44.4
11	**Property Tax**	2.1	10.1	12.2	13.6	(1.4)	11.4	14.1	(2.6)
12	**Capital Tax**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Accretion**[1]	49.6	247.0	296.6	294.5	2.1	327.8	307.2	20.6
14	**(Earnings) Losses on Segregated Funds**[1]	(68.0)	(172.1)	(240.1)	(286.2)	46.1	(350.9)	(304.6)	(46.3)
15	**Used Fuel Storage and Disposal**[1]	3.0	24.0	27.0	17.0	10.1	44.5	24.0	20.5
16	**Waste Management Variable Expenses**[2]	0.2	0.8	1.0	0.8	0.1	2.9	0.7	2.2
17	**Interest**	2.2	9.4	11.6	11.9	(0.3)	14.7	6.9	7.8
18	**Total Costs Before Income Tax**	(4.9)	146.5	141.6	86.1	55.5	129.4	82.8	46.6
19	**Income Tax - Current**[3]	0.0	0.0	0.0	0.0	0.0	0.0	8.6	(8.6)
20	**Income Tax - Future**[4]	10.5	9.8	20.3	40.2	(19.9)	(44.0)	34.3	(78.3)
21	**Total Costs**	5.6	156.4	161.9	126.3	35.6	85.5	125.7	(40.3)
22	**Bruce Lease Net Revenues** (line 9 - line 21)	32.7	35.5	68.2	128.1	(59.8)	(117.7)	143.0	(260.8)

Notes:
1 Amounts in cols. (c) and (f) are from Ex. H1-1-2 Table 19, cols. (b) and (c) respectively.
2 Amount in col. (c) is from Ex. H1-1-2 Table 19, line 5, col. (b). Amount in col. (f) is the sum of $1.8M for ongoing waste management variable expenses from Ex. H1-1-2 Table 19, line 5, col. (c) and $1.1M for expenses resulting from the implementation of new CNSC requirements in 2012 per note 4 in Ex. H1-1-2 Table 19.
3 Amounts in cols. (c) and (f) are from Ex. H1-1-2 Table 14b, line 22, cols. (a) and (b) respectively.
4 Amounts in cols. (c) and (f) are from Ex. H1-1-2 Table 14b, line 32, cols. (a) and (b) respectively.

Numbers may not add due to rounding.

Table 14b
(Updated version of Ex. H1-1-1 Table 14b)
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2011 and 2012

Line No.	Particulars	2011 Actual	2012 Actual
		(a)	(b)
	Determination of Taxable Income		
1	**Earnings (Loss) Before Tax**[1]	88.6	(161.7)
	Additions for Tax Purposes - Temporary Differences:		
2	**Base Rent Accrual**	37.1	39.1
3	**Depreciation**	33.2	78.9
4	**Accretion**	296.6	327.8
5	**Used Fuel and Waste Management Expenses**	28.0	47.4
6	**Receipts from Nuclear Segregated Funds**	24.0	28.1
7	**Adjustment Related to Embedded Derivative**	23.5	283.5
8	**Other**	2.1	2.1
9	**Total Additions - Temporary Differences**	444.6	807.0
	Deductions for Tax Purposes - Permanent Differences:		
10	**Deferred Rent Revenue**	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:		
11	**CCA**	6.6	6.1
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**	68.5	83.8
13	**Contributions to Nuclear Segregated Funds**	105.5	74.9
14	**Earnings (Losses) on Nuclear Segregated Funds**	240.1	350.9
15	**Supplemental Rent Payment Reduction**	0.0	77.9
16	**Total Deductions - Temporary Differences**	420.7	593.5
17	**Taxable Income/(Loss) Before Loss Carry-Over**	98.3	37.6
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	(98.3)	(37.6)
19	**Taxable Income After Loss Carry-Over**	0.0	0.0
	Determination of Current Income Taxes		
20	**Taxable Income After Loss Carry-Over**	0.0	0.0
21	**Income Tax Rate - Current**	26.50%	25.00%
22	**Income Taxes - Current**	0.0	0.0
	Determination of Future Income Taxes		
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)	(17.8)	17.2
24	**Income Tax Rate - Current**	26.50%	25.00%
25	**Future Income Taxes - Short-Term**	4.7	(4.3)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)	41.7	196.3
27	**Income Tax Rate - Long-Term**	25.00%	25.00%
28	**Future Income Taxes - Long-Term**	(10.4)	(49.1)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)	(98.3)	(37.6)
30	**Income Tax Rate - Current**	26.50%	25.00%
31	**Future Income Taxes - Tax Loss / Tax Loss Carry-Over**	26.0	9.4
32	**Future Income Tax - Total** (line 25 + line 28 + line 31)	20.3	(44.0)
	Income Tax Rate - Current		
33	**Federal Tax**	16.50%	15.00%
34	**Provincial Tax**	11.75%	11.25%
35	**Provincial Manufacturing & Processing Profits Deduction**	-1.75%	-1.25%
36	**Total Income Tax Rate - Current**	26.50%	25.00%
	Income Tax Rate - Long-Term		
37	**Federal Tax**	15.00%	15.00%
38	**Provincial Tax**	10.00%	10.00%
39	**Provincial Manufacturing & Processing Profits Deduction**	0.00%	0.00%
40	**Total Income Tax Rate - Long-Term**	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. H1-1-2 Table 14a, Line 9 and Total Costs Before Income Tax in Ex. H1-1-2, Table 14a, Line 18 for the corresponding years.

Table 15
(Updated version of Ex. H1-1-1 Table 15)
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Actual 2012
		(a)	(b)	(c)
	January - February 2011:			
1	**PARTS Amortization[1] ($M)**	8.2		
2	**Nuclear Actual Production[2] (TWh)**	8.8		
3	**Rider A Rate - EB-2007-0905[3] ($/MWh)**	2.00		
4	**Amount Recovered for Nuclear Deferral and Variance Accounts ($M)** (line 2 x line 3)	17.6		
5	**Addition to Variance Account ($M)** (line 1 - line 4)	(9.4)		
	March 2011 - December 2012:			
6	**Nuclear Forecast Production - EB-2010-0008[4] (TWh)**		41.5	51.5
7	**Nuclear Actual Production[2] (TWh)**		39.8	49.0
8	**Production Variance (TWh)** (line 6 - line 7)		1.7	2.5
9	**Nuclear Deferral and Variance Over/Under Recovery Rate[5] ($/MWh)**		4.33	4.33
10	**Addition to Variance Account ($M)** (line 8 x line 9)		7.4	10.7

Notes:

1 Amount from Ex. H1-1-1 Table 8, col. (b), line 4 and Ex. H1-1-2 Table 8, col. (b), line 4. This amount represents the portion of the amount recovered for nuclear deferral and variance accounts in January and February 2011 attributable to the PARTS Deferral Account balance approved for recovery in EB-2007-0905 over 45 months ending December 31, 2011. All other nuclear accounts approved for recovery in EB-2007-0905 were fully amortized as of December 31, 2010.

2 Amount for full year 2011 is as reported in OPG's Management's Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

3 For January and February 2011, the approved nuclear payment rider per the EB-2007-0905 Payment Amounts Order is $2.00/MWh.

4 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, with the full year 2011 production adjusted for the months of January and February 2011.

5 For March 2011 to December 2012, the approved nuclear payment rider per EB-2010-0008 Payment Amounts Order is $4.33/MWh.

Numbers may not add due to rounding.

Table 16
(Updated version of Ex. H1-2-1 Table 1)
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)[3]	Amortization 2013[4]	Amortization 2014[4]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	17.1	17.1	24	8.6	8.6	17.1	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	34.0	24	17.0	17.0	34.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	N/A	0.0	0.0	0.0	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	N/A	0.0	0.0	0.0	4.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(2.5)	24	(1.3)	(1.3)	(2.5)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	N/A	0.0	0.0	0.0	1.1
8	**Pension and OPEB Cost Variance - Hydroelectric**	15.1	15.1	48	3.8	3.8	7.6	7.6
9	**Impact for USGAAP Deferral - Hydroelectric**	2.8	2.8	24	1.4	1.4	2.8	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	(3.9)	24	(1.9)	(1.9)	(3.9)	0.0
11	**Total** (lines 1 though 10)	113.8	110.9		51.7	51.7	103.3	10.5
12	**Total Approved 2011-2012 Production[5] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.60	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for lines 3, 4 and 7. See Ex. H1-1-1 Sections 4.4 and 5.5.
3 From Ex. H1-2-1 Table 1, col. (c).
4 Col. (b) amount x 12 months / recovery period in col. (c).
5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Table 17
(Updated version of Ex. H1-2-1 Table 2)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)[3]	Amortization 2013[4]	Amortization 2014[4]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	208.0	208.0	24	104.0	104.0	208.0	0.0
2	**Nuclear Development Variance**	30.2	30.2	24	15.1	15.1	30.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.7	24	0.8	0.8	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear[5]**	13.1	11.8	24	5.9	5.9	11.8	1.3
5	**Bruce Lease Net Revenues Variance**	310.5	310.5	48	77.6	77.6	155.2	155.2
6	**Income and Other Taxes Variance - Nuclear**	(32.5)	(32.5)	24	(16.3)	(16.3)	(32.5)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	253.3	24	126.7	126.7	253.3	0.0
8	**Pension and OPEB Cost Variance - Nuclear**	309.1	309.1	48	77.3	77.3	154.6	154.6
9	**Impact for USGAAP Deferral - Nuclear**	60.3	60.3	24	30.1	30.1	60.3	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	6.9	24	3.5	3.5	6.9	0.0
11	**Total** (lines 1 through 10)	1,160.6	1,159.2		424.7	424.7	849.4	311.1
12	**Total Approved 2011-2012 Production[6] (TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						8.34	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for line 4. See Note 4.
3 From Ex. H1-2-1 Table 2, col. (c).
4 Col. (b) amount x 12 months / recovery period in col. (c).
5 Col. (b) amount excludes other additions to account in 2012 of $1.3M relating to a Darlington refurbishment capital cost variance to be cleared at a later date.
6 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Table 18
(Updated version of Ex. H2-1-1 Table 1)
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	6,391.2	7,174.5	7,935.9
2	**Darlington Refurbishment Adjustment**	2	497.4	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		6,888.6	7,174.5	7,935.9
4	**Used Fuel Storage and Disposal Variable Expenses**		23.5	26.0	51.9
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.1	0.9	3.8
6	**Accretion Expense**		382.2	399.0	432.6
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(122.0)	(104.0)	(115.5)
8	**Consolidation and Other Adjustments**		1.2	0.3	0.9
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		7,174.5	7,496.7	8,309.7
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	1.3
12	**Closing Balance** (line 9 + line 10 + line 11)		7,174.5	7,935.9	8,034.1
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		7,031.6	7,335.6	8,122.8
	NUCLEAR SEGREGATED FUNDS BALANCE				
14	**Opening Balance**	1	5,058.7	5,564.9	5,895.3
15	**Earnings (Losses)**		417.7	220.7	355.7
16	**Contributions**		150.2	145.0	107.1
17	**Disbursements**		(61.8)	(35.3)	(41.6)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,564.9	5,895.3	6,316.5
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,311.8	5,730.1	6,105.9
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)				
20	**Opening Balance** (line 3 - line 14)		1,829.9	1,609.6	2,040.6
21	**Closing Balance** (line 9 - line 18)		1,609.6	1,601.4	1,993.2
22	**Average Unfunded Nuclear Liability Balance** ((line 20 + line 21)/2)		1,719.8	1,605.5	2,016.9
	ASSET RETIREMENT COSTS (ARC)				
23	**Opening Balance**	1	1,098.0	1,504.5	1,914.7
24	**Reconciliation Adjustment**	5	(42.7)	0.0	0.0
25	**Darlington Refurbishment Adjustment**	2	475.5	0.0	0.0
26	**Adjusted Opening Balance** (line 23 + line 24 + line 25)		1,530.8	1,504.5	1,914.7
27	**Depreciation Expense**		(26.3)	(29.0)	(127.2)
28	**Closing Balance Before Year-End Adjustments** (line 26 + line 27)		1,504.5	1,475.4	1,787.5
29	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)
30	**Closing Balance** (line 28 + line 29)		1,504.5	1,914.7	1,510.5
31	**Average Asset Retirement Costs** ((line 26 + line 28)/2)		1,517.6	1,490.0	1,851.1
32	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 22 or line 31)		1,517.6	1,490.0	1,851.1

Notes:
1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 1.
2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.
3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. H1-1-2 Table 20, associated with the current approved ONFA Reference Plan effective January 1, 2012.
4 As a result of the implementation of new CNSC requirements in 2012, in accordance with GAAP, OPG's total year-end 2012 ARO was adjusted to include $21.9M for certain facilities with Waste Nuclear Substance Licenses. The timing of notification from the CNSC of the new requirements did not allow for assessment, in conjunction with the Province, of the incorporation of the impact of these requirements as part of the 2012 ONFA Reference Plan. OPG is reviewing the ONFA for potential incorporation of the impacts of the requirements into the next ONFA Reference Plan.
Of the total $21.9M adjustment, $19.5M relates to a facility exclusively in support of the Bruce facilities and $2.4M ($1.3M for prescribed facilities and $1.1M for Bruce facilities) relates to a legacy facility that is no longer used to support OPG's current operations, resulting in an ARO adjustment related to the prescribed facilities of $1.3M. In accordance with GAAP and as consistent with the treatment for the purposes of OPG's financial statements, the amount of $2.4M was reflected as an expense, rather than an adjustment to ARC, in 2012. Therefore, there was no ARC adjustment for the prescribed facilities.
5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E in rate base. Total rate base is not impacted.

Table 19
(Updated version of Ex. H2-1-1 Table 2)
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	5,315.0	5,357.0	6,107.7
2	**Darlington Refurbishment Adjustment**	2	(204.4)	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,110.7	5,357.0	6,107.7
4	**Used Fuel Storage and Disposal Variable Expenses**		17.8	27.0	44.5
5	**Low & Intermediate Level Waste Management Variable Expenses**		0.9	1.0	1.8
6	**Accretion Expense**		283.1	296.6	327.8
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(57.5)	(68.1)	(83.7)
8	**Consolidation and Other Adjustments**		1.9	(1.0)	0.6
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		5,357.0	5,612.6	6,398.7
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	20.6
12	**Closing Balance** (line 9 + line 10 + line 11)		5,357.0	6,107.7	7,125.5
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		5,233.8	5,484.8	6,253.2
	NUCLEAR SEGREGATED FUNDS BALANCE				
14	**Opening Balance**	1	5,187.2	5,680.9	6,002.5
15	**Earnings (Losses)**		418.0	240.1	350.9
16	**Contributions**		113.9	105.5	74.9
17	**Disbursements**		(38.2)	(24.0)	(28.1)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,680.9	6,002.5	6,400.1
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,434.0	5,841.7	6,201.3
	ASSET RETIREMENT COSTS (ARC)				
20	**Opening Balance**	1	1,035.8	817.6	1,288.8
21	**Reconciliation Adjustment**	5	(9.6)	0.0	0.0
22	**Darlington Refurbishment Adjustment**	2	(182.4)	0.0	0.0
23	**Adjusted Opening Balance** (line 20 + line 21 + line 22)		843.7	817.6	1,288.8
24	**Depreciation Expense**		(26.1)	(23.9)	(69.6)
25	**Closing Balance Before Year-End Adjustments** (line 23 + line 24)		817.6	793.7	1,219.2
26	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1
27	**New CNSC Requirements Adjustment**	4	0.0	0.0	19.5
28	**Closing Balance** (line 25 + line 26 + line 27)		817.6	1,288.8	1,944.8
29	**Average Asset Retirement Costs** ((line 23 + line 25)/2))		830.7	805.7	1,254.0

Notes:

1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 2.

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. H1-1-2 Table 20, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 As a result of the implementation of new CNSC requirements in 2012, in accordance with GAAP, OPG's total year-end 2012 ARO was adjusted to include $21.9M for certain facilities with Waste Nuclear Substance Licenses. Due to the timing of notification from the CNSC of the new requirements, there was insufficient time to assess, in conjunction with the Province, the incorporation of the impact of these requirements as part of the 2012 ONFA Reference Plan. OPG is reviewing the ONFA for potential incorporation of the impacts of the requirements into the next ONFA Reference Plan.

Of the total $21.9M adjustment, $19.5M relates to a facility exclusively in support of the Bruce facilities and $2.4M ($1.3M fo prescribed facilities and $1.1M for Bruce facilities) relates to a legacy facility that is no longer used to support OPG's current operations, for a total ARO adjustment for the Bruce facilities of $20.6M. In accordance with GAAP and as consistent with the treatment in for the purposes of OPG's financial statements, the amount of $2.4M was reflected as an expense, rather than an adjustment to ARC, in 2012. The ARC adjustment for the Bruce facilities was therefore $19.5M.

5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E. Total Bruce Lease net revenues are not impacted.

Numbers may not add due to rounding.

Table 20
(Updated version of Ex. H2-1-1 Table 3)
Impact of Current Approved ONFA Reference Plan - Assignment of ARO and ARC Adjustments to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Actual 2011[1]:								
1	**Decommissioning Program**	(111.0)	(209.3)	(296.2)	(616.5)	(188.5)	(194.3)	(382.8)	(999.3)
2	**Low and Intermediate Level Waste Storage Program**	125.7	83.6	64.2	273.6	183.0	26.9	209.9	483.5
3	**Low and Intermediate Level Waste Disposal Program**	245.3	194.9	36.3	476.5	317.0	42.1	359.2	835.7
4	**Used Fuel Disposal Program**	(31.4)	(59.7)	(104.3)	(195.4)	(8.0)	(25.9)	(33.9)	(229.3)
5	**Used Fuel Storage Program**	139.7	166.4	194.9	501.1	78.1	264.6	342.6	843.7
6	**ARO Adjustment Assignment to Station Level**	368.4	175.9	(105.1)	439.2	381.6	113.5	495.1	934.3
7	**Asset Retirement Cost Adjustment** (from line 6)	368.4	175.9	(105.1)	439.2	381.6	113.5	495.1	934.3

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Actual 2012:								
8	**Decommissioning Program**	(18.8)	(43.0)	0.0	(61.8)	(33.0)	(40.4)	(73.4)	(135.2)
9	**Low and Intermediate Level Waste Storage Program**	(14.2)	11.9	(10.0)	(12.2)	60.3	21.1	81.4	69.2
10	**Low and Intermediate Level Waste Disposal Program**	(60.1)	(8.0)	(52.4)	(120.5)	76.0	37.3	113.3	(7.2)
11	**Used Fuel Disposal Program**	(74.0)	194.6	(176.6)	(56.0)	289.3	315.9	605.1	549.1
12	**Used Fuel Storage Program**	(11.3)	(22.2)	7.1	(26.4)	(10.4)	(9.9)	(20.3)	(46.7)
15	**ARO Adjustment Assignment to Station Level**	(178.5)	133.3	(231.7)	(276.9)	382.2	323.9	706.1	429.2
16	**Asset Retirement Cost Adjustment**	(178.5)	133.3	(231.7)	(276.9)	382.2	323.9	706.1	429.2

Notes:
1 Amounts for year-end 2011 ARO and ARC adjustments are from Ex. H2-1-1 Table 3, lines 1 through 7.

Numbers may not add due to rounding.

Table 21
(Updated version of Ex. I1-1-2 Table 1)
Computation of Percent Change in Payment Amounts
EB-2010-0008 to EB-2012-0002

Line No.	Description	Notes	EB-2010-0008 Board Approved Payment Amounts	EB-2012-0002 Proposed Payment Amounts	Percent Change in Payment Amounts
			(a)	(b)	(c)
	PERCENT CHANGE IN PAYMENT AMOUNTS				
	AVERAGE RATE:				
1	**Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	34.13	38.38	12%
2	**Nuclear Rate Including Rider ($/MWh)**	2	55.85	59.86	7%
3	**Approved 2011-12 Regulated Hydroelectric Production (TWh)**	3	39.7	39.7	
4	**Approved 2011-12 Nuclear Production (TWh)**	3	101.9	101.9	
5	**Total Approved 2011-12 Production (TWh)** (line 3 + line 4)		141.6	141.6	
6	**Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 3 / line 5)		9.57	10.76	
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		40.19	43.07	
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		49.77	53.84	
9	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2010-0008 TO EB-2012-0002**				**8%**
	(((line 8 col. (b) - line 8 col. (a)) / line 8 col. (a))/100)				

Notes:
1. EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus line 5.
   EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus proposed rider from Ex. H1-1-2 Table 16, line 13.
2. EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus line 5.
   EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus proposed rider from Ex. H1-1-2 Table 17, line 13.
3. From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Table 22
Typical Consumer Bill Impact

Line No.	Description	Residential
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409
3	**Typical Bill[1] ($/Month)**	116.30
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**1.66**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**1.4%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	53.84
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	4.07
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	8%
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8
11	Forecast of Provincial Demand[3] (TWh)	285.6
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%

Notes:

1 For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills. Typical Consumption includes line losses.

2 See L-3-5 EP-02

3 Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).

`

Numbers may not add due to rounding.

Table 23
Calculation of Interim Period Shortfall Riders

Line No.	Account	March 1, 2013 Implementation		April 1, 2013 Implementation	
		Regulated Hydroelectric	Nuclear	Regulated Hydroelectric	Nuclear
		(a)	(b)	(c)	(d)
1	**Approved Rider ($/MWh)**[1]	2.60	8.34	2.60	8.34
2	**Interim Rider ($/MWh)**[2]	0.0	4.33	0.0	4.33
5	**2011/2012 Average January Production Forecast (TWh)**[3]	1.6	4.8	1.6	4.8
6	**2011/2012 Average February Production Forecast (TWh)**[3]	1.5	4.2	1.5	4.2
7	**2011/2012 Average March Production Forecast (TWh)**[3]			1.7	4.3
8	**Interim Period Production Forecast (TWh)**	3.2	9.0	4.9	13.2
	(line 5 + line 6 for March 1 implementation)				
	(line 5 + line 6 + line 7 for April 1 implementation)				
9	**Production Forecast Used to Set Proposed Rider (TWh)**[4]	39.7	101.9	39.7	101.9
10	**Interim Period Shortfall Rider ($/MWh)** (((line 1 - line 2) x line 8) / (line 9 - line 8))	0.23	0.39	0.37	0.60

Notes:

1 Rider proposed for approval by OPG in EB-2012-0002 application.
Regulated Hydroelectric from Ex. H1-1-2 Table 16, line 13. Nuclear from Ex. H1-1-2 Table 17, line 13.

2 Per EB-2012-0002 Procedural Order No. 1.

3 Based on average of 2011 and 2012 production for the given month, from monthly production figures provided in L-2-1 Staff-16, Attachment 1, Table 2 (Regulated Hydroelectric) and Table 3 (Nuclear).

4 Regulated Hydroelectric from Ex. H1-1-2 Table 16, line 12. Nuclear from Ex. H1-1-2 Table 17, line 12.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's proposed approach for clearing the deferral and variance account balances described in Ex. H1-1-1.

2.0 SUMMARY

OPG is requesting payment riders for regulated hydroelectric and nuclear production to recover audited actual deferral and variance account balances as of December 31, 2012, using separate payment riders for the nuclear and hydroelectric accounts, effective January 1, 2013. Amortization amounts and payment riders described in this exhibit are based on projected December 31, 2012 balances. Prior to payment rider finalization, OPG will file audited December 31, 2012 balances, similar to the process followed in setting riders in EB-2010-0008. Since the audited balances will not be available until early February, 2013 and the current riders expire December 31, 2012, OPG proposes that the OEB continue and declare interim the EB-2010-0008 approved nuclear rider as of January 1, 2013. OPG is proposing that the current hydroelectric rider be allowed to expire because it is negative and, thus, its continuation would only increase the shortfall to be recovered. OPG proposes to recover resulting variances in recovery amounts during the period January 1, 2013 to the implementation date of the new riders through additional Interim Period Shortfall Riders ("IPSR") for each of regulated hydroelectric and nuclear production determined in the manner described in Section 6.0.

The methodology for the proposed recovery of deferral and variance account balances is described in Section 3.0. The recovery of hydroelectric deferral and variance account balances is discussed in Section 4.0. The recovery of nuclear deferral and variance account balances is discussed in Section 5.0. Interim Period Shortfall Riders are discussed in Section 6.0.

3.0 METHODOLOGY

The use of payment riders in the form of a $/MWh rate is consistent with the OEB's Decision and Payment Amounts Order in EB-2010-0008**.**

Riders are calculated in three steps. First, a recovery period is determined for each account to be cleared. Second, based on each account's recovery period, the amount to be amortized over the period is determined. Finally, the total amount to be amortized during the period is divided by energy production to determine the payment rider.

As this is not a complete cost of service application with a future test period, OPG will not calculate riders on the basis of a future production forecast. Rather, OPG proposes to use the EB-2010-0008 OEB-approved 2011/2012 test period forecast production to calculate riders. As the payment riders are based on forecast production, any differences between forecast and actual production will cause, in any event, an over or under-recovery variance, which will be recorded in the Hydroelectric and Nuclear Over/Under Recovery Variance Accounts as consistent with the EB-2010-0008 Decision and Payment Amounts Order.

4.0 RECOVERY OF HYDROELECTRIC DEFERAL AND VARIANCE ACCOUNTS

The method of calculation for the regulated hydroelectric payment rider is as shown in Ex. H1-2-1, Table 1 using projected December 31, 2012 balances. The actual rider will be set during the finalization process for the payment rider order using audited December 31, 2012 balances.

OPG is proposing to defer clearance of the Hydroelectric Incentive Mechanism and Hydroelectric Surplus Baseload Generation Variance Accounts and the hydroelectric portion of the Capacity Refurbishment Variance Account for the reasons discussed in Ex. H1-1-1, Sections 4.4 and 5.5.

Consistent with the payment amounts orders in EB-2007-0905 and EB-2010-0008, OPG proposes a single payment rider beginning January 1, 2013 to recover all applicable regulated hydroelectric account balances. The use of one payment rider is administratively simple.

OPG proposes to clear the December 31, 2012 balances in the regulated hydroelectric deferral and variance accounts on a straight line basis using amortization periods for the various accounts as described below.

The balance in the Pension and OPEB Cost Variance Account will be amortized over a 48-month period from January 1, 2013 to December 31, 2016. This extended amortization period was chosen to lessen ratepayer impact.

All other account balances will be amortized over a 24-month period from January 1, 2013 to December 31, 2014. This recovery period is also consistent with the EB-2010-0008 approved recovery period for the Tax Loss Variance Account ending December 31, 2014.

The total amortization amount over the 24-month period January 1, 2013 to December 31, 2014 is divided by the EB-2010-0008 approved test period regulated hydroelectric production forecast to calculate the payment amount rider.

The derivation of amortization amounts and calculation of the regulated hydroelectric rider based on projected year-end 2012 balances is shown at Ex. H1-2-1, Table 1.

5.0 RECOVERY OF NUCLEAR DEFERRAL AND VARIANCE ACCOUNTS

The method of calculation of the nuclear rider is as shown in Ex. H1-2-1, Table 2 using projected December 31, 2012 balances. The actual rider will be set during the finalization process for the payment rider order using audited December 31, 2012 balances.

Consistent with the payment amounts orders in EB-2007-0905 and EB-2010-0008, OPG proposes a single rider beginning January 1, 2013 to recover nuclear account balances. The use of one payment rider is administratively simple.

OPG proposes to clear the December 31, 2012 balances in the nuclear deferral and variance accounts on a straight line basis using amortization periods for the various accounts described below.

The balances in the Bruce Lease Net Revenues Variance Account and the Pension and OPEB Cost Variance Account will be amortized on a straight line basis over the 48-month period from January 1, 2013 to December 31, 2016. These extended amortization periods were chosen to lessen ratepayer impact.

Other account balances will be amortized on a straight line basis over the 24-month period from January 1, 2013 to December 31, 2014. As noted in Section 4.0 above this recovery period is also consistent with the EB-2010-0008 approved recovery period for the Tax Loss Variance Account ending December 31, 2014.

The total amortization amount over the 24-month period January 1, 2013 to December 31, 2014 is divided by the EB-2010-0008 approved test period nuclear production forecast to calculate the payment amount rider.

The Derivation of amortization amounts and calculation of the nuclear rider based on projected year-end 2012 balances is shown at Ex. H1-2-1, Table 2.

6.0 INTERIM PERIOD SHORTFALL RIDERS

Since the new payment riders will not be implemented by January 1, 2013, OPG is requesting separate IPSR for regulated hydroelectric and nuclear production to recover the revenue shortfall resulting from the difference during the interim period between approved payment riders and the interim riders. Consistent with the proposal to use the EB-2010-0008 approved forecast production to set the new riders, the interim period production values used to calculate the differences would be equal to the average of the 2011 and 2012 forecast production for the corresponding months underpinning the EB-2010-0008 payment amounts. The IPSR would be effective until December 31, 2014.

The IPSR for each of regulated hydroelectric and nuclear would be calculated as follows:

$$\text{IPSR} = \frac{[(\text{Approved Rider} - \text{Interim Rider}) \times \text{Interim Period Production Forecast}]}{(\text{Production Forecast used to set Approved Rider} - \text{Interim Period Production Forecast})}$$

If, for example, the implementation date of the new approved rider is March 1, 2013, the interim period production forecast would be based on the January and February values in the production forecast used to calculate the new rider.

Table 1
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Projection
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	6,391.2	7,174.5	7,935.9
2	**Darlington Refurbishment Adjustment**	2	497.4	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		6,888.6	7,174.5	7,935.9
4	**Used Fuel Storage and Disposal Variable Expenses**		23.5	26.0	52.7
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.1	0.9	3.8
6	**Accretion Expense**		382.2	399.0	433.3
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(122.0)	(104.0)	(152.8)
8	**Consolidation and Other Adjustments**		1.2	0.3	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		7,174.5	7,496.7	8,273.0
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(184.0)
11	**Closing Balance** (line 9 + line 10)		7,174.5	7,935.9	8,089.0
12	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		7,031.6	7,335.6	8,104.5
	NUCLEAR SEGREGATED FUNDS BALANCE				
13	**Opening Balance**	1	5,058.7	5,564.9	5,895.3
14	**Earnings (Losses)**		417.7	220.7	316.9
15	**Contributions**		150.2	145.0	185.7
16	**Disbursements**		(61.8)	(35.3)	(63.6)
17	**Closing Balance** (line 13 + line 14 + line 15 + line 16)		5,564.9	5,895.3	6,334.4
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		5,311.8	5,730.1	6,114.8
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)				
19	**Opening Balance** (line 3 - line 13)		1,829.9	1,609.6	2,040.6
20	**Closing Balance** (line 9 - line 17)		1,609.6	1,601.4	1,938.6
21	**Average Unfunded Nuclear Liability Balance** ((line 19 + line 20)/2)		1,719.8	1,605.5	1,989.6
	ASSET RETIREMENT COSTS (ARC)				
22	**Opening Balance**	1	1,098.0	1,504.5	1,914.7
23	**Reconciliation Adjustment**	4	(42.7)	0.0	0.0
24	**Darlington Refurbishment Adjustment**	2	475.5	0.0	0.0
25	**Adjusted Opening Balance** (line 22 + line 23 + line 24)		1,530.8	1,504.5	1,914.7
26	**Depreciation Expense**		(26.3)	(29.0)	(126.6)
27	**Closing Balance Before Year-End Adjustments** (line 25 + line 26)		1,504.5	1,475.4	1,788.0
28	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(184.0)
29	**Closing Balance** (line 27 + line 28)		1,504.5	1,914.7	1,604.1
30	**Average Asset Retirement Costs** ((line 25 + line 27)/2)		1,517.6	1,490.0	1,851.3
31	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 21 or line 30)		1,517.6	1,490.0	1,851.3

Notes:
1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 1.
2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.
3 Adjustments recorded on December 31, 2011 and expected to be recorded on December 31, 2012, as per Ex. H2-1-1 Table 3, associated with the current approved ONFA Reference Plan effective January 1, 2012.
4 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E in rate base. Total rate base is not impacted.

Table 2
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Projection
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	5,315.0	5,357.0	6,107.7
2	**Darlington Refurbishment Adjustment**	2	(204.4)	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,110.7	5,357.0	6,107.7
4	**Used Fuel Storage and Disposal Variable Expenses**		17.8	27.0	43.5
5	**Low & Intermediate Level Waste Management Variable Expenses**		0.9	1.0	1.8
6	**Accretion Expense**		283.1	296.6	328.5
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(57.5)	(68.1)	(120.4)
8	**Consolidation and Other Adjustments**		1.9	(1.0)	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		5,357.0	5,612.6	6,361.1
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	563.0
11	**Closing Balance** (line 9 + line 10)		5,357.0	6,107.7	6,924.0
12	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		5,233.8	5,484.8	6,234.4
	NUCLEAR SEGREGATED FUNDS BALANCE				
13	**Opening Balance**	1	5,187.2	5,680.9	6,002.5
14	**Earnings (Losses)**		418.0	240.1	322.3
15	**Contributions**		113.9	105.5	113.5
16	**Disbursements**		(38.2)	(24.0)	(42.5)
17	**Closing Balance** (line 13 + line 14 + line 15 + line 16)		5,680.9	6,002.5	6,395.8
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		5,434.0	5,841.7	6,199.1
	ASSET RETIREMENT COSTS (ARC)				
19	**Opening Balance**	1	1,035.8	817.6	1,288.8
20	**Reconciliation Adjustment**	4	(9.6)	0.0	0.0
21	**Darlington Refurbishment Adjustment**	2	(182.4)	0.0	0.0
22	**Adjusted Opening Balance** (line 19 + line 20 + line 21)		843.7	817.6	1,288.8
23	**Depreciation Expense**		(26.1)	(23.9)	(69.1)
24	**Closing Balance Before Year-End Adjustments** (line 22 + line 23)		817.6	793.7	1,219.7
25	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	563.0
26	**Closing Balance** (line 24 + line 25)		817.6	1,288.8	1,782.7
27	**Average Asset Retirement Costs** ((line 22 + line 24)/2))		830.7	805.7	1,254.3

Notes:
1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 2.
2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.
3 Adjustments recorded on December 31, 2011 and expected to be recorded on December 31, 2012, as per Ex. H2-1-1 Table 3, associated with the current approved ONFA Reference Plan effective January 1, 2012.
4 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E. Total Bruce Lease net revenues are not impacted.

PENSION AND OPEB COST VARIANCE ACCOUNT

1.0 OVERVIEW

The OEB established the Pension and OPEB (Other Post Employment Benefits) Cost Variance Account in its EB-2011-0090 Decision and Order on Motion dated June 23, 2011. The additions to the account for 2011 consist of $4.0M for regulated hydroelectric and $91.9M for nuclear. The projected additions to the account in 2012 are $12.6M for regulated hydroelectric and $237.7M for nuclear. The calculations of the account additions are shown in Ex. H1-1-1, Table 5 and 5a. The projected 2012 year-end balances including interest total $16.7M for regulated hydroelectric and $333.1M for nuclear as shown in Ex. H1-1-1, Table 1.

OPG has complied with all of the requirements established for this account by the OEB in the above decision and order, as discussed in Section 2.0 below. Section 3.0 explains the main drivers of the variances between the actual (2011) and projected (2012) amounts and the corresponding EB-2010-0008 forecast amounts.

As noted in Ex. H1-3-1, OPG seeks the extension of the Pension and OPEB Cost Variance Account until the effective date of OPG’s next payment amounts order. Section 4.0 sets out OPG’s support for this request and presents OPG’s proposal to calculate account additions made after 2012 using the same approach that has been used for 2011 and 2012. Section 5.0 presents a forecast of 2013 pension and OPEB amounts and resulting impacts on the variance account.

2.0 REQUIREMENTS FROM EB-2011-0090

The requirements set out in the EB-2011-0090 Decision and Order on Motion (pp. 14-15) for the Pension and OPEB Cost Variance Account are cited below (in bold italicized font), followed by a discussion of how OPG has met each requirement.

- ***OPG shall record the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the Decision and the resulting payment***

amounts order, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the test period for the prescribed generation facilities.

The EB-2010-0008 Decision and Payment Amounts Order reflects forecast pension and OPEB costs, pension plan contributions and OPEB payments for OPG's regulated hydroelectric and nuclear operations as shown in Ex. H1-1-1, Tables 5 and 5a. The calculation of the forecast income tax impacts is provided in Ex. H1-1-1, Table 5a, note 2. The actual (2011) and projected (2012) costs, pension contributions/OPEB payments and tax impacts are discussed in Section 3.0 below. In deriving these amounts, OPG has followed the same accounting standards and actuarial methodologies that were used to derive the EB-2010-0008 forecasts.

- ***The Pension and OPEB Cost Variance Account [shall] be effective as of March 1, 2011.***

  Consistent with the standard approach taken with other deferral and variance accounts discussed in Ex. H1-1-1, additions to the Pension and OPEB Cost Variance Account are calculated by comparing monthly actual amounts, starting in March 2011, to reference amounts calculated as 1/12 of the average of the full year forecast amounts for 2011 and 2012. The calculation of the reference amounts is provided in Ex. H1-1-1, Table 5, note 2 for pension and OPEB costs and Ex. H1-1-1, Table 5a, note 2 for income tax impacts. No amounts have been recorded in the account for January and February 2011.

- ***The entries in the variance account for 2011 and 2012 will be determined on the same basis and under the same circumstances as the pre-filed evidence.***

  The same accounting standards and actuarial methodology were applied in determining actual (2011) and projected (2012) pension and OPEB costs as those reflected in the EB-2010-0008 payment amounts. OPG has included an unqualified audit opinion from Ernst & Young LLP as Attachment 1, which confirms that the 2011 account balance has been recorded on a CGAAP basis using the methodology reflected in EB-2010-0008 (Attachment 1, page 5).

OPG has also provided an independent actuary's report from Aon Hewitt (Attachment 2) in support of the December 31, 2011 balance in the variance account. This report states:

> "Aon Hewitt confirms that the above OPG-wide costs were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology is consistent with the methodology as outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008 and used to determine the forecast pension and OPEB costs reflected in the regulated prices established by the OEB in that proceeding." (Attachment 2, p. 4)

The accounting standards and actuarial methodology are summarized at page 4 of the Aon Hewitt report.

Prior to the finalization of the payment amounts order for this Application, OPG will file documents similar to Attachments 1 and 2 confirming 2012 amounts. OPG proposes that these documents be filed and reviewed at the same time as the proposed auditors' report on the December 31, 2012 balances of all deferral and variance accounts as discussed in Ex. H1-2-1.

- ***There will be no entries in the variance account related to changes in accounting standards, such as IFRS or USGAAP.***

OPG's current payment amounts were established in the EB-2010-0008 Payment Amounts Order on the basis of CGAAP. As noted in Ex. A3-1-1, OPG is recording amounts in all deferral and variance accounts, including the Pension and OPEB Cost Variance Account, on the same basis as was used to establish the payment amounts (i.e., CGAAP). This is confirmed in Attachment 1. OPG is recording the financial impacts on OPG's prescribed assets of the adoption of USGAAP, which relate solely to long-term disability plan costs in the Impact for USGAAP Deferral Account, as discussed in Ex. A3-1-2.

- ***There will be no principal entries posted to the variance account after December 31, 2012. However, the entries for the year 2012 may be adjusted when the year-end accounting and contribution levels are finalized in early 2013.***

OPG's request for approval to continue to record principal entries into the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order is discussed below in Section 4.0.

- ***The Board expects OPG to provide an independent actuary's report and an audit opinion which will describe the methodology followed, the assumptions made by management, and the amounts recorded in the account, and which will confirm that the evidence is consistent with the CGAAP standards and actuarial methods that were contained or reflected in the evidence for the 2011-2012 payment amounts application.***

As discussed above, OPG has provided an unqualified audit opinion from Ernst & Young LLP (Attachment 1) and an independent actuary's report from Aon Hewitt (Attachment 2) in support of the December 31, 2011 balance in the variance account as well as the 2011 actual pension and OPEB amounts and the underlying methodologies, assumptions and calculations used to derive them. OPG will file similar documents confirming 2012 information by early February 2013.

The projected minimum pension contributions required for 2011 through 2013 are established by the most recent actuarial valuation for funding purposes, which was prepared as at January 1, 2011. This Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011 for OPG ("Funding Valuation Report") is provided in Attachment 3.

3.0 VARIANCE FOR 2011 AND 2012

3.1 Calculation of Pension and OPEB Costs and Variances

Exhibit H1-1-1, Table 5 presents the calculation of additions to the Pension and OPEB Cost Variance Account for 2011 and 2012. This Table also presents the actual 2011 and projected 2012 amounts, as well as the EB-2010-0008 forecast amounts for 2011 and 2012. Differences between the actual/projected amounts and the EB-2010-0008 forecast amounts give rise to the entries in the Pension and OPEB Cost Variance Account.

The 2011 and 2012 OEB-approved costs were projected based on an estimate of the values for the benefit obligations and pension fund assets at the end of each of 2009 to 2011. The process used to develop these estimates was detailed in EB-2010-0008, Ex. F4-T3-S1, Section 6.3. The same process also was used to develop the current projection of 2013 amounts discussed below.[1]

The details of the 2011 variance in pension and OPEB costs are found in the chart on page 5 of Attachment 1 (as well as in Ex. H1-1-1, Table 5). The details of the 2011 variance in associated tax impacts are found in the chart on page 7 of Attachment 1 (as well as in Ex. H1-1-1, Table 5a). The assumptions used for the 2011 costs are provided at page 6 of Attachment 1 in the schedule accompanying the auditors' report and at page 4 of the independent actuary's report (Attachment 2).

Attachment 2 (pages 3 and 5) provides OPG's total pension and OPEB costs for all of 2011. OPG's total actual pension contributions and OPEB payments for 2011 are provided at page 5 of Attachment 2. The entries recorded in the variance account are based on the portion of these costs and contributions/payments attributable to the prescribed assets for the period March through December 2011.

The projected 2012 pension and OPEB costs have been calculated in the same manner as the 2011 costs. OPG's total costs been determined by Aon Hewitt, as outlined in their 2012 report provided in Attachment 4. At this point, these projections closely approximate the final 2012 cost. Therefore, the forecast 2012 additions to the Pension and OPEB Cost Variance Account shown in Ex. H1-1-1, Tables 5 and 5a will be very close to the final amounts at December 31, 2012, absent any significant unexpected changes to legislation or OPG's operations.

[1] The full year forecasts of each of registered pension plan contributions and OPEB payments for the prescribed facilities are also reflected in the EB-2010-0008 Payment Amounts Order at lines 17 and 18, respectively, of Table 5 for 2011 and Table 7 for 2012.

The 2012 OPG-wide projected costs were determined using the actual values of the benefit obligations and pension fund assets as at December 31, 2011 and the final assumptions made at that time. These are provided at pages 3 and 4 of the 2012 Aon Hewitt report (Attachment 4). The minimum contributions levels for 2012 have been established in the Funding Valuation Report.

3.2 Sources and Amounts of Variance

Chart 1 below presents the assumptions for discount rates and asset returns used to determine the actual (2011) and projected (2012) pension and OPEB costs as well as those used to derive the forecast amounts approved in EB-2010-0008.[2] Both sets of assumptions were derived in the same manner. Lower than forecast discount rates are the primary source of variance recorded in this account. Differences in assets values and returns also contribute to the variance.

Chart 1

Assumption	2011 Actual	2012 Projection	2011 OEB-Approved	2012 OEB-Approved
Discount rate for pension	**5.80% per annum**	**5.10% per annum**	6.80% per annum	6.80% per annum
Discount rate for other post retirement benefits	**5.80% per annum**	**5.20% per annum**	7.00% per annum	7.00% per annum
Discount rate for long-term disability	**4.70% per annum**	**4.00% per annum**	5.25% per annum	5.25% per annum
Expected long-term rate of return on pension fund assets	**6.5% per annum**	**6.5% per annum**	7.0% per annum	7.0% per annum
Rate of return used to project year-end pension fund asset values	**N/A**	**N/A**	9.0% in 2009 and 7.0% per annum in 2010	9.0% in 2009 and 7.0% per annum in each of 2010 and 2011

[2] The OEB-approved assumptions were previously presented in EB-2010-0008 Ex. F4-3-1, Section 6.3, Chart 8.

Projections of rates of return used to set year-end pension fund asset values are not required for the calculation of actual (2011) or projected (2012) pension costs because the actual prior year-end asset values are known. The actual returns on pension fund assets were 15.0 per cent in 2009, 12.2 per cent in 2010 and 6.9 per cent in 2011. Over the first six months of 2012 the return on pension fund assets has been 3.41 per cent.

As shown in Ex. H1-1-1, Table 5, the actual pension costs for the ten months ended December 31, 2011 and the projected costs for full year 2012 are higher than the corresponding reference amounts based on EB-2010-0008 approved forecasts by $2.0M and $7.9M, respectively, for regulated hydroelectric and $46.8M and $148.6M, respectively, for nuclear. The higher costs for 2011 and 2012 are primarily due to lower discount rates and expected long-term rate of return on pension fund assets than those underpinning the forecasts as shown in Chart 1. The discount rates were provided by the actuaries and the long-term return rate was developed based on their input; both rates are included in the 2012 Actuarial Report (Attachment 4). The lower-than-forecast discount rates reflect the impact of financial market conditions on long-term bond rates. The lower expected rate of return reflects lower anticipated returns due to global financial market conditions. These impacts are partially offset by higher-than-forecast pension fund asset values at the end of 2010 and 2011 due to higher than forecast fund performance in 2009 and 2010.

The actual OPEB costs for 2011 and the projected costs for 2012 are higher than the corresponding reference amounts based on EB-2010-0008 approved forecasts by $0.9M and $2.9M, respectively, for regulated hydroelectric and by $24.5M and $52.7M, respectively, for nuclear due to lower assumptions for discount rates.

3.3 Income Tax Impacts

The income tax impacts associated with pension and OPEB plans are calculated in accordance with the methodology for the calculation of regulatory income taxes approved by the OEB in EB-2010-0008 and reflected in the EB-2010-0008 Payment Amounts Order in Tables 6 and 7 for 2011 and 2012, respectively. This methodology was discussed in EB-2010-0008, Ex. F4-2-1. As noted in that exhibit, regulatory taxable income is computed by making additions and deductions to the regulatory earnings before tax for items with different accounting and tax treatment. In Section 3.3.5, that evidence also explains that pension and OPEB accounting costs are added to earnings before tax, as they are not deductible under the *Income Tax Act* (Canada), whereas as pension contributions and OPEB payments are deductible and, therefore, are deducted from earnings before tax. Therefore, the income tax impacts included in the variance account are computed based on the net amount of additions or deductions to earnings before tax based on actual and forecast pension and OPEB costs and related contributions and payments.[3]

The calculations of the tax impacts are provided in Ex. H1-1-1, Table 5a. For the ten-month period ending December 31, 2011, actual regulatory income tax impact is higher than forecast by $1.0M for regulated hydroelectric and $20.5M for nuclear. For 2012, projected regulatory income tax impact is higher than forecast by $1.9M for regulated hydroelectric and $36.4M for nuclear. These variances occur because the increase in taxes associated with the higher actual pension and OPEB costs over the forecast amounts is greater than the decrease in taxes associated with the higher cash amounts for pension contributions and OPEB payments.

4.0 CONTINUATION OF THE VARIANCE ACCOUNT

4.1 Basis for Continuing the Variance Account

OPG is requesting authority to continue recording entries in the Pension and OPEB Cost Variance Account until the effective date of OPG's next payment amounts order. OPG is requesting the extension of this account to provide a mechanism to consider the appropriate level of these costs in a future proceeding. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting such entries into this account subsequent to December 31, 2012 pending the OEB's decision.

The EB-2011-0090 Decision and Order on Motion concluded that the original 2011-2012 payment amounts decision (EB-2010-0008, Decision with Reasons, March 10, 2011) had

[3] Forecast income tax impacts for the purposes of the account are calculated using the same approach of averaging over the 2011-2012 period as the reference amounts for pension and OPEB costs (see Section 2.0).

erroneously rejected OPG's updated forecast of pension and OPEB costs in the mistaken belief that the updated forecast was less rigorously prepared than the originally filed estimate. The OEB approved the creation of the Pension and OPEB Cost Variance Account as the simplest and most expeditious method of remedying this error and established an end date of December 31, 2012 for this account.

When the Motion for Review was heard, it was expected that updated forecast pension and OPEB costs would be established when OPG applied for new payment amounts covering 2013 and 2014, and the established end-date for the account reflects that expectation.[4] However, given that the current payment amounts will continue beyond December 31, 2012, OPG is seeking to extend this variance account until the effective date of the next payment amounts order.

Extending the Pension and OPEB Variance Account will allow the OEB to consider the appropriate levels of these costs beyond 2012 and provide a mechanism for OPG to recover those costs that the OEB approves. In contrast, if the account is not extended, after 2012 OPG will be limited to recovering the pension and OPEB costs that were set by the original EB-2010-0008 decision, amounts that the OEB has already found to have been set in error.

Extending the account also would afford symmetric treatment for ratepayers in the event that pension and OPEB costs were to fall due to rising discount rates or other reasons. The OEB noted that symmetrical treatment of OPG and ratepayers was an advantage of establishing a variance account in the EB-2011-0090 Decision and Order on Motion (p. 14).

4.2 Variance Account Entries after 2012

OPG proposes that the Pension and OPEB Cost Variance Account will continue to record, on a monthly basis starting in January 2013, the difference between OPG's actual pension and OPEB costs including associated tax impacts determined on a CGAAP basis and the corresponding reference amounts used to calculate the 2011 and 2012 additions (discussed

[4] Discussion of the fact that OPG's next payment amount application was expected to cover 2013-2014 is found in the EB-2010-0008, Decision with Reasons at pages 66, 72, and 135.

in Section 2.0). This is the same methodology used to calculate the 2011 and 2012 account additions. This approach also is consistent with the standard methodology that OPG intends to use in calculating additions to other deferral and variance accounts after December 31, 2012, as discussed in Ex. H1-3-1.

On that basis, the monthly reference pension and OPEB cost amounts will be 1/12 of $15.1M ($7.0M for pension and $8.2M for OPEB) for regulated hydroelectric and 1/12 of $301.4M ($138.4M for pension and $163.0M for OPEB) for nuclear.[5] The monthly reference tax impact amounts for regulated hydroelectric and nuclear will be 1/12 of $0.5M and $10.3M, respectively.[6]

Consistent with the OEB-approved approach for OPG's other deferral and variance accounts, OPG proposes that the variance account would continue to record simple interest as applied to the opening monthly balance of the account using the interest rates set by the OEB from time to time pursuant to the OEB's interest rate policy.

Based on the above-described methodology, OPG's current projection of the total 2013 addition to the Pension and OPEB Cost Variance Account is $367.2M. The details of the projected 2013 additions are provided in Chart 2 below. These projections were developed using current estimates of the 2013 CGAAP pension and OPEB amounts for OPG's regulated hydroelectric and nuclear operations, and the corresponding reference amounts developed above.

---

[5] The calculation of the regulated hydroelectric reference amounts is based on Ex. H1-1-1, Table 5, note 2, line 5a, columns. (a) and (c) for pension and OPEB costs, respectively with slight differences due to rounding in Table 5. The calculation of the nuclear reference amounts is based on Ex. H1-1-1 Table 5, note 2, line 5a, columns. (b) and (d) for pension and OPEB costs, respectively.

[6] The calculation of the regulated hydroelectric and nuclear reference tax impact amounts is based on Ex. H1-1-1 Table 5a, note 2, line 9a and 10a, respectively.

Chart 2

	2013 Projection		
$M	**Regulated Hydro**	**Nuclear**	**Total**
Pension Costs	10.9	213.6	224.5
OPEB Costs	3.4	63.6	67.0
Tax Impact	3.7	72.2	75.8
Total	17.9	349.4	367.2

The projected increases in 2013 pension and OPEB costs are primarily due to lower discount rates. For 2013 the lower projected discount rates are: 4.70 per cent for pension, 4.80 per cent for other post retirement benefits and 3.70 per cent for long-term disability benefits. These rates reflect the continuing downward trend in long-term bond rates attributable to current financial market conditions.

LIST OF ATTACHMENTS

Attachment 1:	Independent Auditors' Report on the Pension and OPEB Cost Variance Account as at December 31, 2011
Attachment 2:	"Report on the CICA 3461 (CGAAP) Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations" for Ontario Power Generation Inc.
Attachment 3:	"Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011" for Ontario Power Generation Inc.
Attachment 4:	"Report on the Estimated Accounting Cost for Fiscal Year 2012" for Ontario Power Generation Inc.

Board Staff Interrogatory #03

Ref: Exh H1-1-1 Table 9
Exh H2-1-1 Tables 1 and 3

Issue Number: 1
Issue: Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Interrogatory

Table 9 provides a summary of the 2012 transactions that give rise to the $180M addition to the Nuclear Liability Deferral Account in 2012, as projected by OPG as at December 31, 2012. Several key calculations are based on "2011" data shown in Table 3 (Exh H2-1-1) regarding impacts arising from changes to the ONFA Reference Plan effective January 1, 2012. Table 3 also provides data for the impacts in 2012.

a) Please explain whether the 2011 data, as at December 31, 2011, listed in Table 3 of Exh H2-1-1 were used to derive incremental amounts for depreciation expense and return on rate base, etc. recorded in the Nuclear Liability Deferral Account for 2012 in Table 9 of Exh H1-1-1. If yes, please confirm that December 31, 2011 is the measurement date for the ONFA Reference Plan effective January 1, 2012.

b) Please provide the revenue requirement impacts including depreciation expense, return on rate base, variable expenses and income tax, that will be recorded as 2013 additions in the Nuclear Liability Deferral Account associated with the impact of changes to the ONFA Reference Plan for 2011 and 2012 shown in Exh H1-1-1 Table 9 and Exh H2-1-1 Tables 1 and 3.

c) Please confirm that the revenue requirements impacts arising from changes in the ONFA Reference Plan effective January 1, 2012 will be proposed for inclusion in the base payment amounts in OPG's next cost service application.

Response

a) Yes, the 2011 data provided in the top portion of Ex. H2-1-1, Table 3 is used to derive the amounts of depreciation expense, return on rate base and associated income tax impacts recorded in the Nuclear Liability Deferral Account for 2012. That data is the source of the asset retirement cost adjustment discussed in Ex H1-1-1, Table 9, Note 2, line 1a.

The measurement date for the ONFA Reference Plan, which OPG understands to mean the date as of which the present value of the liability reflected in the Reference Plan is calculated, is January 1, 2012. However, as noted in response to L-1-1 Staff-02, the 2012 additions to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account would be the same using either December 31, 2011 or January 1, 2012 as the starting point for the underlying calculations.

b) An estimate of the revenue requirement impact to be recorded into the Nuclear Liability Deferral Account in 2013 is as follows:

Line no.	**Particulars**	**$M**
1	Depreciation Expense	52
2	Return on Rate Base	2
3	Variable Expenses – Used Fuel Management	26
4	Variable Expenses – Low & Intermediate Level Waste Management	1
5	Income Tax Impact	29
6	**Addition to Deferral Account**	**110**

The above estimate reflects the actual adjustments to the asset retirement obligation and asset retirements costs at the end of 2012, as provided in the bottom portion of Ex. H1-1-2 Table 20, and related inputs and assumptions. The estimate also reflects the impact of contributions to the nuclear segregated funds as per the segregated fund contribution schedule approved by the Province in December 2012 based on the approved 2012 ONFA Reference Plan.

c) OPG intends to include the revenue requirement impacts from changes in the ONFA reference plan effective January 1, 2012 in its next application to set nuclear base payment amounts.

Board Staff Interrogatory #14

Ref: OPG Motion Proceeding EB-2011-0090
Exh H1-1-1 Table 5

Issue Number: 1
Issue: Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Interrogatory

In the decision in proceeding EB-2011-0090, issued on June 23, 2011, the Board approved the establishment of the Pension and OPEB Cost Variance Account. At page 14 of the decision, it states that, "The clearance of this account will be reviewed in OPG's **next payment amounts application hearing**." [emphasis added]

a) Please explain why OPG is seeking clearance of this account in the current application and not in a future payment amounts proceeding.

b) OPG filed an application for 2011-2012 payment amounts on May 26, 2010, (EB-2010-0008). On September 30, 2010, OPG filed an impact statement that forecast that pension and OPEB expenses would increase significantly. The pension and OPEB cost forecast for 2011 in EB-2010-0008 was $287.1M. The impact statement showed a forecast cost of $427.2M. Please confirm that the actual pension and OPEB incurred cost for 2011 was lower than the impact statement forecast cost of $427.2M, and explain why the costs were lower.

c) Please provide references to previous proceedings and any further information to support the allocation of amounts between regulated hydroelectric and nuclear in the Pension and OPEB Cost Variance Account.

Response

a) OPG is applying to recover the variance between pension/OPEB costs reflected in EB-2010-0008 approved rates and actual pension and OPEB costs incurred for the March 1, 2011 to December 31, 2012 period. OPG will provide audited December 31, 2012 deferral and variance account balances. There is no additional information that would be available as a result of delaying the clearance of these accounts to a subsequent proceeding - OPG would rely on the same evidence now as it would in the future. With the expectation of a growing balance over time there is no reason to delay recovery of the requested amounts, and such recovery is necessary to ensure OPG has adequate cash resources for financial sustainability.

b) Confirmed. However, although the actual costs for OPG's regulated business for full year 2011 of $405.7M, calculated as the sum of pension and OPEB costs for both regulated hydroelectric and nuclear shown in Ex. H1-1-1, Table 5, note 3, were 5 per cent lower than the total updated amount of $427.2M shown in the Impact Statement (Ex. N1-1-1) in EB-2010-0008, they are 41 per cent above the original forecast of $287.1M for 2011 costs provided in the EB-2010-0008 pre-filed evidence shown in Ex. N1-1-1.

The actual costs for 2011 are lower than the projected amount presented in the Impact Statement mainly due to a higher-than-projected pension fund asset value and slightly higher-than-projected discount rates at the end of 2010, partially offset by a reduction in the expected long-term rate of return on pension fund assets for 2011.

Specifically, the actual return on pension fund assets was 12.2 per cent for 2010 (EB-2012-0002, Ex. H2-1-3, p. 7), whereas the Impact Statement reflected an actual return of 2.5 per cent as of the end of August 2010 (EB-2010-0008, Ex. N1-1-1, p. 2) and a projected return at nil for the remainder of the year (EB-2010-0008, Ex. H1-3-1, Attachment 1, Appendix B).

The actual discount rates for 2011 were 5.8 per cent for pension and other post retirement benefit costs and 4.7 per cent for long-term disability benefit plan costs (EB-2012-0002, Ex. H2-1-3, p. 6). The Impact Statement was based on projected discount rates of 5.7 per cent and 4.4 per cent, respectively (EB-2010-0008, Ex. N1-1-1, p. 2).

The expected long-term rate of return on pension fund assets of 6.5 per cent used to determined the actual costs for 2011 (EB-2012-0002, Ex. H2-1-3, p. 6) was lower than the rate of 7.0 per cent assumed for the purposes of the Impact Statement (EB-2010-0008, Ex. H1-3-1, Attachment 1, Appendix B).

c) The assignment of forecast and actual/projected pension and OPEB costs to each of regulated hydroelectric and nuclear for the purposes of the Pension and OPEB Cost Variance Account uses the same methodology as that described in the EB-2010-0008 pre-filed evidence at Ex. F4-3-1, section 6.3.3. This methodology was reflected in the EB-2010-0008 payment amounts. It was also referenced at p. 12 of the Affidavit of N. Reeve (Exhibit B) filed with OPG's Notice of Motion in EB-2011-0090, and outlined in the first paragraph on page 5 of Attachment 1 to Ex. H2-1-3.

The assignment of forecast and actual/projected pension contributions and OPEB payments to each of regulated hydroelectric and nuclear also uses the same methodology as that reflected in the EB-2010-0008 payment amounts and as outlined on p. 7 of Attachment 1 to Ex. H2-1-3.

SEC Interrogatory #04

Ref: H2/1/2, p. 2-3

Issue Number: 1
Issue: Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Interrogatory

Please provide a table showing, for each past year since the commencement of the Bruce Lease for which the Applicant has actual data, and for each future year for which the Applicant has a forecast, a) the total base rent revenue, b) the total supplemental rent revenue net of any rebates, and c) the total costs of the Applicant related to the Bruce facilities. Please use the format and categories used in Ex. H1/1/1, Table 14a.

Response

The requested information for periods prior to 2011 is not relevant to OPG's application to clear balances accumulated in the deferral and variances accounts in 2011 and 2012. Nevertheless, OPG provides historical information for the period during which OPG has been regulated by the OEB in attached Table 1, which includes replicated information for 2011 presented in Ex. H1-1-1, Table 14a and for 2012 presented in Ex. H1-1-2, Table 14a. Table 1 also includes forecast information under CGAAP for 2013, which reflects the actual financial results for 2012, including the asset retirement obligation and asset retirement cost adjustments at the end of 2012 as provided in the bottom portion of Ex. H1-1-2, Table 20, and the impact of contributions to the nuclear segregated funds as per the segregated fund contribution schedule approved by the Province in December 2012 based on the approved 2012 ONFA Reference Plan.

OPG declines to provide projected estimates for years beyond 2013 as the information is not relevant to the clearance of the 2012 audited actual account balances.

Table 1
CGAAP Bruce Lease Net Revenues - 2008 to 2013 ($M)

Line No.	Particulars	2008 Actual[1]	2009 Actual[1]	2010 Actual[2]	2011 Actual[3]	2012 Actual[4]	2013 Projected
		(a)	(b)	(c)	(d)	(e)	(f)
	Revenues:						
1	**Site Services (OPG to Bruce Power)**	0.7	0.7	2.0	1.1	0.7	0.7
2	**Low & Intermediate Level Waste Services**	9.1	6.3	6.3	14.6	5.8	17.0
3	**Cobalt-60**	0.6	0.3	0.5	0.5	0.4	0.5
4	**Total Services**	10.4	7.3	8.8	16.2	6.8	18.2
5	**Fixed (Base) Rent**	72.7	40.9	40.9	40.9	40.9	40.9
6	**Supplemental Rent**	173.7	(11.3)	134.4	161.0	(92.1)	206.7
7	**Amortization of Initial Deferred Rent**	11.7	11.8	12.1	12.1	12.1	12.1
8	**Total Rent**	258.1	41.4	187.4	214.0	(39.1)	259.7
9	**Total Revenue**	268.5	48.7	196.2	230.2	(32.3)	277.9
	Costs:						
10	**Depreciation**	61.0	60.4	35.8	33.2	78.9	103.2
11	**Property Tax**	(1.0)	12.9	12.6	12.2	11.4	13.3
12	**Capital Tax**	3.6	3.4	1.0	0.0	0.0	0.0
13	**Accretion**	267.4	279.3	283.1	296.6	327.8	367.8
14	**(Earnings) Losses on Segregated Funds**	183.9	(386.2)	(418.0)	(240.1)	(350.9)	(330.5)
15	**Used Fuel Storage and Disposal**	14.0	14.4	17.8	27.0	44.5	51.6
16	**Waste Management Variable Expenses and Facilities Removal Costs**	3.6	3.1	12.5	1.0	2.9	2.8
17	**Interest**	19.3	18.7	14.7	11.6	14.7	12.8
18	**Total Costs Before Income Tax**	551.8	6.0	(40.4)	141.6	129.4	221.0
19	**Income Tax - Current**	0.0	0.0	0.0	0.0	0.0	4.7
20	**Income Tax - Future**	(70.1)	5.3	59.1	20.3	(44.0)	6.0
21	**Total Costs**	481.7	11.3	18.6	161.9	85.5	231.7
22	**Bruce Lease Net Revenues** (line 9 - line 21)	(213.2)	37.4	177.6	68.2	(117.7)	46.2

Notes:

1. All revenue amounts for 2008 and 2009 are from EB-2010-0008 Ex. G2-2-1, Table 2, cols. (b) and (c), respectively.
   All cost amounts for 2008 and 2009 are from EB-2010-0008 Ex. G2-2-1, Table 5, cols. (b) and (c), respectively.
   All 2008 amounts are for the full year with the exception of income taxes, which, as explained in EB-2010-0008, Ex. G2-2-1 at pages 14-15 and note 3 to accompanying Table 5, are for the period April 1 to December 31, 2008. OPG did not separately compute income taxes on a stand-alone, GAAP basis for Bruce revenues and costs prior to April 1, 2008.
2. All amounts for 2010 are those underpinning the December 31, 2010 audited balance of the Bruce Lease Net Revenues Variance Account approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.
3. All amounts for 2011 are from EB-2012-0002 Ex. H1-1-1 Table 14a and Ex. H1-1-2 Table 14a.
4. All amounts for 2012 are from EB-2012-0002 Ex. H1-1-2, Table 14a.

SEC Interrogatory #17

Ref: H2/2/1, p. 1

Issue Number: 1
Issue: Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Interrogatory

Please provide a detailed breakdown of the $49.4 million of costs claimed, with supporting material to allow a full prudence review. Please provide all approved internal budgets relating to this spending, and internal reports of variances to budget. Please provide details of all additional personnel hired as a result of this spending, and all third party expenses such as contractor costs incurred.

Response

Table 1 below provides a breakdown by each of the key elements of actual 2011 and 2012 planning and preparation work for New Nuclear at Darlington ("NND"). Actual 2011 and 2012 costs have declined to $42.5M from the projection of $49.4M referenced in the question.

Table 1

2011 + 2012 combined - $M	Labour	Overtime	Augmented Staff	Materials	Other Contracted services	Licensing fees	Other	Total
Regulatory Hearings	1.6	0.1	-	0.0	1.0	-	-	2.7
Regulatory Compliance	3.1	0.0	-	-	4.5	6.4	0.2	14.1
Site Readiness	1.9	-	-	0.0	2.4	-	0.2	4.4
Vendor Selection/Project Planning	3.5	-	0.4	-	13.1	-	0.4	17.4
Stakeholder Consultation	0.8	-	-	0.0	3.0	-	0.0	3.8
Total	10.9	0.1	0.4	0.0	24.0	6.4	0.8	42.5

The activities that underpin the key elements and support the prudence of the expenditures made are described at H2-2-1, pp. 2-3. The $2.7M of regulatory hearing costs are for OPG regular staff and external legal for preparation and participation in the Joint Review Panel public hearing in March 2011. The regulatory compliance costs of $14.1M are primarily for ongoing work to address compliance and monitoring of the EA commitments made by OPG and the License to Prepare the Site recommendations as set out in the Joint Review Panel report (e.g.. the other contracted services includes external engineering company performing a cost-benefit analysis for condenser cooling water options) plus CNSC fees. The $4.4 M of site readiness activities undertaken to ensure readiness to construct are detailed in L-1-2-AMPCO-1. In addition to OPG regular labour costs associated with vendor selection and project planning, the $17.4M for Vendor Selection/Project Planning includes $13.1M of Other Contracted Services. This includes engaging external legal and contract specialist support for the procurement process along with payments to Westinghouse and SNC Lavalin/Candu Energy Inc. to prepare detailed construction plans schedules and cost estimates for two potential nuclear reactors at Darlington. These expenditures are appropriate to help inform the government's decision on whether to move forward with new nuclear at the Darlington site. The $3.8M of the stakeholder consultation actual and projected expenditure includes $3.0M payments in total for the Clarington Host Agreement.

The 2011 internal approved budget was $58.1M and assumed the resumption of the procurement process and selection of preferred vendor in 2011, allowing a quick ramp up for proceeding with the project in 2012. However, it became apparent to OPG that the procurement would not proceed in 2011 and as a result OPG focused on the other NND work activities as described in Ex. H2-2-1, pp. 2-3 enabling NND expenditures to be limited to $17.3M. The expenditures that were made in 2011 were those that were appropriate and useful in underpinning the work done in 2012, all with the purpose of ensuring site readiness to construct new units following selection of a preferred vendor consistent with the Minister's Letter to OPG dated March 8, 2011 (Attachment 1 to Ex. H2-2-1).

The 2012 internal approved budget was $54.4M and assumed the resumption of the procurement process in early 2012. However, while the Ontario government resumed the procurement process, it was delayed until mid-2012. As a result, 2012 actual expenditures are reduced to $25.2M.

Table 2 below summarizes the variances described above.

Table 2
New Build at Darlington -Variance Summary

	2011 Actual $M	2011 OPG Budget $M	Variance $M	2012 Actual $M	2012 OPG Budget $M	Variance $M
Expenditures	**17.3**	**58.1**	**-40.8**	**25.2**	**54.4**	**-29.2**

As shown in Table 3 below, OPG has been actively undertaking planning and preparation for NND since 2009 and no increases in overall staff FTEs occurred in 2011 or 2012.

Table 3
New Build at Darlington -Variance Summary

	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Expenditures- $M	57.8	23.2	17.3	25.2
Staffing (FTEs)	64	40	40	23

SEC Interrogatory #23

Ref: H2/1/3, p. 11,and L/2/1, Staff 24

Issue Number: 1
Issue: Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Interrogatory

Please provide the calculations behind the figures in Chart 2.

Response

The calculations of projected 2013 additions to the Pension and OPEB Cost Variance Account shown in Ex. H1-1-2, Chart 4 are provided in Attachment 1 to this response as Tables 1 and 1a, in the format of Ex. H1-1-1, Tables 5 and 5a, respectively.

Table 1
Pension and OPEB Cost Variance Account[1]
Summary of Projected Account Transactions - 2013 ($M)

Line No.	Particulars	Projected 2013		
		Hydroelectric	Nuclear	Total
		(a)	(b)	(c)
1	**Forecast Pension Costs - EB-2010-0008**[2]	7.0	138.4	145.4
2	**Forecast OPEB Costs - EB-2010-0008**[2]	8.2	163.0	171.2
3	**Total Forecast Pension and OPEB Costs**	15.1	301.4	316.5
4	**Projected Pension Costs**[3]	19.7	362.2	381.9
5	**Projected OPEB Costs**[3]	13.5	247.0	260.5
6	**Total Projected Pension and OPEB Costs**	33.2	609.2	642.4
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)	12.8	223.8	236.6
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)	5.3	84.0	89.3
9	**Addition to Variance Account - Regulatory Tax Impact**[4]	3.8	69.2	73.0
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)	21.9	377.0	399.0

Notes:

1 Excludes Pension and OPEB amounts related to the Nuclear Waste Management Organization ("NWMO") consolidated into OPG's financial statements. OPG Supplementary Pension Plan amounts are included with OPEB amounts. All cost amounts are presented on a CGAAP basis.

2 As discussed in Ex. H2-1-3, section 4.2, the forecast amounts for 2013 have been determined using the same methodology used to calculate the 2011 and 2012 additions to the Pension and OPEB Cost Variance Account account at Ex. H1-1-1 Table 5 and Ex. H1-1-2 Table 5. Specifically, amounts at line 1, cols. (a) and (b) and at line 2, cols. (a) and (b) are from Ex. H1-1-1 Table 5, line 1, cols. (d) and (e) and line 2, cols. (d) and (e), respectively (and similarly for Ex. H1-1-2 Table 5).

3 Projected amounts are discussed in Ex. H1-1-2, section 4.0.

4 From Ex. L-1-7 SEC-23 Table 1a, line 8.

Table 1a

Pension and OPEB Cost Variance Account[1]

Calculation of Projected Tax Impact - 2013 ($M)

Line No.	Particulars	Projected 2013 Hydroelectric	Projected 2013 Nuclear	Projected 2013 Total
		(a)	(b)	(c)
1	**Forecast Regulatory Income Tax Impact[2]**	0.5	10.3	10.8
	Projected Additions / Deductions to Regulatory Earnings Before Tax			
2	**Pension Costs[3]** (from Ex. L-1-7 SEC-23 Table 1, line 4)	19.7	362.2	381.9
3	**OPEB Costs[3]** (from Ex. L-1-7 SEC-23 Table 1, line 5)	13.5	247.0	260.5
4	**Less: Pension Plan Contributions[3]**	15.8	289.8	305.6
5	**Less: OPEB Payments[3]**	4.4	80.9	85.3
6	**Net Additions to Regulatory Earnings Before Tax**	13.0	238.6	251.6
7	**Projected Regulatory Income Tax Impact[4]** (line 6 x tax rate / (1 - tax rate))	4.3	79.5	83.9
8	**Addition to Variance Account - Regulatory Tax Impact** (line 7 - line 1)	3.8	69.2	73.0

Notes:

1 Excludes Pension and OPEB amounts related to the Nuclear Waste Management Organization ("NWMO") consolidated into OPG's financial statements. OPG Supplementary Pension Plan amounts are included with OPEB amounts. All cost amounts are presented on a CGAAP basis.

2 As discussed in Ex. H2-1-3, section 4.2, the forecast amounts for 2013 have been determined using the same methodology used to calculate the 2011 and 2012 additions to the Pension and OPEB Cost Variance Account account at Ex. H1-1-1, Table 5a and Ex. H1-1-2 Table 5a. Specifically, amounts at line 1, cols. (a) and (b) are from Ex. H1-1-1, Table 5a, line 1, cols. (d) and (e), respectively (and similarly for Ex. H1-1-2 Table 5).

3 Projected amounts are based on assumptions reflected in the pension and OPEB cost amounts discussed in Ex. H1-1-2, section 4.0.

4 Tax rate for 2013 is 25.00%.

AMPCO Interrogatory #04

Ref: Exhibit H2-1-1 Page 2 Line 18 to Page 3 Line

Issue Number: 2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Preamble: OPG indicates that the current approved OFNA Reference Plan is projected to result in higher accounting nuclear liabilities due to:

- Higher construction costs for both DGR, which reflect more detailed engineering and advanced design concepts;
- Higher Used Fuel and L&ILW Storage program costs that reflect current operational experience and assumptions about station end-of-life dates.

a) Please explain the above two bullets more fully, including by explaining why the OFNA Reference Plan resulted in higher liabilities and the amount of the increase of such liabilities arising from same.

Response

As more fully explained in L-1-1 Staff-04 a) and b), OPG's accounting liabilities for nuclear decommissioning and nuclear waste management ("Nuclear Liabilities") are based on baseline cost estimates from the ONFA Reference Plan in effect. The two bullets cited in the preamble to this question, including the interrelated impacts of the increase in fixed costs arising from a higher number of used fuel bundles and the increased amount of low and intermediate level waste ("L&ILW") to be managed (noted in the third bullet at Ex. H2-1-1, p. 2, lines 26 to p. 3, line 4), are major contributing factors to the higher baseline cost estimates in the 2012 ONFA Reference Plan. As such, these factors also result in higher nuclear liabilities. The higher nuclear liabilities discussed below includes the impact of higher fixed costs.

Specifically, Ex. H2-1-1, Table 3 sets out, by program, the actual year-end 2011 and projected 2012 year-end increases in the Nuclear Liabilities, the calculation of which is detailed in Ex. L-1-7 SEC-15.

The higher construction cost impacts from the first cited bullet, including the above-noted interrelated fixed cost impacts, apply to both the deep geologic repository ("DGR") for L&ILW and for used fuel and, as such, contribute to increases in nuclear liabilities for both the L&ILW Disposal Program and the Used Fuel Disposal Program shown in the above referenced Table 3 at lines 3, 4, 10 and 11. The impact of these higher costs on the nuclear liabilities across the two programs is estimated at approximately $300M, and reflects the following:

<u>Low and Intermediate Level Waste DGR</u>

- The previous cost estimate for the DGR was based on a high level conceptual design, while the current cost estimate was developed based on completing 7-10% of preliminary engineering.
- Increased size of the DGR to accommodate higher forecast L&ILW volume to be managed.

<u>Used Fuel DGR</u>

- The constant dollar increase in the estimated construction costs is primarily due to the update of the repository design and the adoption of the “in-floor” borehole placement method for used fuel containers. The previous cost estimate assumed the “in-room” placement method. A higher number of used fuel bundles to be managed also contributed to the increase in the estimated construction costs.

The higher costs for the Used Fuel Storage Program referenced in the second bullet cited in the question, including the interrelated fixed cost impacts, translate into an increase in the nuclear liabilities of approximately $820M, as shown in the above referenced Table 3 at lines 5 and 12. The following factors contribute to this increase:

- Security costs have increased as a result of enhanced requirements. These security requirements reflect the enhancement of standards, as defined by the Canadian Nuclear Safety Commission (“CNSC”), for protection of used fuel in both dry storage facilities during and after station shut down and wet bays after station shut down.
- The cost estimate reflects cost increases for accelerating the emptying of wet fuel bays into dry storage containers resulting from a strategic decision to empty aging wet bays as soon as possible rather than to leave used fuel in the bays for extended periods, particularly after station shut down. This strategy was endorsed by the CNSC as part of OPG’s recently completed CNSC Financial Guarantee hearing process.
- Extended nuclear station end-of-life dates resulted in higher sustaining capital requirements and additional committed operating costs. These costs will be incurred over the longer station lives.

The higher costs for the L&ILW Storage Program referenced in the second cited bullet, including the above-noted interrelated fixed cost impacts, translate into an increase in the nuclear liabilities of approximately $485M, as shown in the above referenced Table 3 at lines 2 and 9. The following factors contribute to the increase:

- A comprehensive re-estimation of costs related to the procurement of re-tube waste containers, transportation packages and construction of the Darlington Re-tube Waste Storage Building to support the additional operating life of the Darlington station was incorporated into the current reference plan.
- The updated estimate included the relocation and repackaging of the dry storage modules from the Pickering Re-tube Component Storage Facility.
- Extended nuclear station end-of-life dates resulted in higher facility sustaining capital requirements and additional committed operating costs. These costs will be incurred over the longer station lives.

- The estimate includes increased costs for operational support and infrastructure costs to maintain waste operations, consistent with current operational needs.

Board Staff Interrogatory #27

Ref: Exh I1-1-2 page 1

Issue Number: 3
Issue: Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Interrogatory

OPG states that the residential customer bill impact of the current application is estimated to be $1.70 per month. Please provide the supporting calculations. Please present the calculations in the format used in Exh I1-1-2 Table 1 (EB-2010-0008).

Response

See Table 1, following page.

Numbers may not add due to rounding.

Table 1
Annualized Residential Consumer Impact Assessment
Test Period January 1, 2013 to December 31, 2014

Line No.	Description	Notes	Test Period Regulated Hydroelectric	 Nuclear	 Total
			(a)	(b)	(c)
1	**Typical Residential Consumer Usage (kWh/Month)**	1	800.0	800.0	800.0
2	**Gross-up for Line Losses**	2	1.0528	1.0528	1.0528
3	**OPG Portion**	3	13.6%	35.0%	48.6%
4	**Residential Consumer Usage of OPG Generation (kWh/Month)**		114.7	294.5	409.2
	(line 1 x line 2 x line 3)				
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY:				
5	**Revenue Requirement Deficiency Requested for Recovery ($M)**		N/A	N/A	N/A
6	**Variance and Deferral Account Amounts Deficiency ($M)**	4	168.9	408.2	577.0
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		168.9	408.2	577.0
8	**Total Approved 2011-12 Production (TWh)**	5	39.7	101.9	141.6
9	**Required Recovery ($/MWh)** (line 7 / line 8)		4.25	4.01	4.08
10	**Typical Monthly Consumer Bill Impact ($)** (line 4 x line 9)		0.49	1.18	1.67
11	**Typical Monthly Residential Consumer Bill ($)**	6	116.30	116.30	116.30
12	**Percentage Increase in Consumer Bills** (line 10 / line 11)		0.42%	1.01%	1.43%

Notes:

1 OPG has used the average monthly consumption for residential consumers used in the OEB "Bill Calculator" for estimating monthly electricity bills. This information can be accessed at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility

2 OPG has used line losses data from Total Loss Factor - Secondary Metered Customers < 5,000 KW reflected in the OEB 2011 Rates Database. This information can be accessed at: http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/2011_RATES_DATABASE_FROM%20TARIFFS.XLS

3 Total based on OPG's forecast production divided by normal weather energy demand forecast for 2013 and 2014. Energy demand forecast is from IESO 18-Month Outlook Update issued June 22, 2012, Table 3.1, which can be accessed at: http://www.ieso.ca/imoweb/monthsyears/monthsahead.asp
Energy demand forecasts for 2013 and 2014 are assumed equal to 2013 forecast, as IESO 18-Month Outlook does not provide 2014 forecast.
Reg. Hydro. and Nuclear portions determined based on energy production.

4 Variance and Deferral Account Amounts Deficiency is computed as follows:

Table to Note 4 - Variance and Deferral Account Amounts Deficiency

Line No.	Item	Reg. Hydro	Nuclear
		(a)	(b)
1a	Amount to be Recovered in EB-2012-0002 ($M) (H1-1-2 Table 16, col. (f), line 11 (Reg. Hydro), H1-1-2 Table 17, col. (f), line 11 (Nuclear))	103.3	849.4
2a	EB 2010-0008 Payment Riders ($/MWh) (EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 5 (Reg. Hydro), EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 5 (Nuclear))	(1.65)	4.33
3a	Total Approved 2011-12 Production (TWh) (line 8)	39.7	101.9
4a	Indicated Production Revenue from EB-2010-0008 Riders ($M) (line 2a x line 3a)	(65.5)	441.2
5a	Variance and Deferral Account Amounts Deficiency ($M) (line 1a - line 4a)	168.9	408.2

5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

6 OPG has developed an average monthly electricity bill for residential consumers based on the monthly bill calculation methodology used in the OEB "Bill Calculator" for estimating monthly electricity bills (using tiered pricing). Delivery costs are computed from information reflected in the OEB 2011 Rates Database. This information can be accessed at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility and http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/2011_RATES_DATABASE_FROM%20TARIFFS.XLS

AMPCO Interrogatory #13

Ref: Exhibit H1-2-1 Page 4 Lines 1-9

Issue Number: 3
Issue: Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Interrogatory

Preamble: OPG intends to amortize the balance of the Bruce Lease Net Revenues Variance and Pension and OPEB Cost Variance Accounts over a 48-month period in order to lessen ratepayer impact, but will be amortizing other accounts on a straight line basis over 2 years.

d) Why is OPG not proposing a similar amortization period (48 months) for all other accounts?

e) Why is OPG not proposing a similar amortization period for the Nuclear Liability Deferral Account and the Tax Loss Variance - Nuclear Account, both of which also have balances in excess of $100 million?

f) Please recast Table 2 (Exhibit H1-2-1) with an amortization period of 48 months for all accounts with a balance greater than $100 million and provide the rate impacts by customer class.

g) Please recast Table 1 and Table 2 (Exhibit H1-2-1) with a recovery period of 24 months for all accounts and provide the rate impacts by customer class.

Response

a) & b) Please see response to L-3-4 CCC-08.

c) Attached Table 1 is a recast of Ex H1-2-1 Table 2 with amortization period of 48 months for all accounts with a projected 2012 balance greater than $100M. On the same basis as described in L-3-2 AMPCO-16, the typical customer monthly bill impacts are $1.00 or 0.9% for residential, $184 or 0.9% for medium/large business, and $5,427 or 1.0% for large industrial customers.

d) Table 2 (attached) is a recast of Ex H1-2-1 Table 1, and Table 3 (attached) is a recast of Ex H1-2-1 Table 2, both with a 24-month recovery period for all accounts. On the same basis as described in L-3-2 AMPCO-16, the typical customer monthly bill impacts are $2.58 or 2.2% for residential, $477 or 2.4% for medium/large business, and $14,048 or 2.5% for large industrial customers.

Numbers may not add due to rounding.

Updated: 2013-02-08
EB-2012-0002
Exhibit L
Tab 3
Schedule 2 AMPCO-13
Attachment 1 - Table 1

Table 1
(Re-cast of Ex. H1-2-1 Table 2, with amortization period of 48 months for all accounts with balances greater than $100M)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	208.0	208.0	48	52.0	52.0	104.0	104.0
2	**Nuclear Development Variance**	30.2	30.2	24	15.1	15.1	30.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.7	24	0.8	0.8	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear[4]**	13.1	11.8	24	5.9	5.9	11.8	1.3
5	**Bruce Lease Net Revenues Variance**	310.5	310.5	48	77.6	77.6	155.2	155.2
6	**Income and Other Taxes Variance - Nuclear**	(32.5)	(32.5)	24	(16.3)	(16.3)	(32.5)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	253.3	48	63.3	63.3	126.7	126.7
8	**Pension and OPEB Cost Variance - Nuclear**	309.1	309.1	48	77.3	77.3	154.6	154.6
9	**Impact for USGAAP Deferral - Nuclear**	60.3	60.3	24	30.1	30.1	60.3	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	6.9	24	3.5	3.5	6.9	0.0
11	**Total** (lines 1 through 10)	1,160.6	1,160.6		309.4	309.4	618.8	541.8
12	**Total Approved 2011-2012 Production[5] (TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						6.07	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for line 4. See Note 4.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 Col. (b) amount excludes other additions to account in 2012 of $0.2M relating to a Darlington refurbisment capital cost variance to be cleared at a later date.
5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Updated: 2013-02-08
EB-2012-0002
Exhibit L
Tab 3
Schedule 2 AMPCO-13
Attachment 1 - Table 2

Table 2
(Re-cast of Ex. H1-2-1 Table 1, with amortization period of 24 months for all accounts)
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	17.1	17.1	24	8.6	8.6	17.1	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	34.0	24	17.0	17.0	34.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	N/A	0.0	0.0	0.0	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	N/A	0.0	0.0	0.0	4.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(2.5)	24	(1.3)	(1.3)	(2.5)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	N/A	0.0	0.0	0.0	1.1
8	**Pension and OPEB Cost Variance - Hydroelectric**	15.1	15.1	24	7.6	7.6	15.1	0.0
9	**Impact for USGAAP Deferral - Hydroelectric**	2.8	2.8	24	1.4	1.4	2.8	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	(3.9)	24	(1.9)	(1.9)	(3.9)	0.0
11	**Total** (lines 1 though 10)	113.8	110.9		55.5	55.5	110.9	2.9
12	**Total Approved 2011-2012 Production[4] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.79	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for lines 3, 4 and 7. See Ex. H1-1-1 Sections 4.4 and 5.5.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Table 3
(Re-cast of Ex. H1-2-1 Table 2, with amortization period of 24 months for all accounts)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	208.0	208.0	24	104.0	104.0	208.0	0.0
2	**Nuclear Development Variance**	30.2	30.2	24	15.1	15.1	30.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.7	24	0.8	0.8	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear**[4]	13.1	11.8	24	5.9	5.9	11.8	1.3
5	**Bruce Lease Net Revenues Variance**	310.5	310.5	24	155.2	155.2	310.5	0.0
6	**Income and Other Taxes Variance - Nuclear**	(32.5)	(32.5)	24	(16.3)	(16.3)	(32.5)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	253.3	24	126.7	126.7	253.3	0.0
8	**Pension and OPEB Cost Variance - Nuclear**	309.1	309.1	24	154.6	154.6	309.1	0.0
9	**Impact for USGAAP Deferral - Nuclear**	60.3	60.3	24	30.1	30.1	60.3	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	6.9	24	3.5	3.5	6.9	0.0
11	**Total** (lines 1 through 10)	1,160.6	1,159.2		579.6	579.6	1,159.2	1.3
12	**Total Approved 2011-2012 Production**[5] **(TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						11.38	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for line 4. See Note 4.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 Col. (b) amount excludes other additions to account in 2012 of $0.2M relating to a Darlington refurbisment capital cost variance to be cleared at a later date.
5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

AMPCO Interrogatory #14

Ref: Exhibit H1-2-1 Page 2 Lines 22-25

Issue Number: 3
Issue: Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Interrogatory

a) Please recast Table 1 assuming OPG does not defer clearance of the Hydroelectric Incentive Mechanism and Hydroelectric Surplus Baseload Generation variance accounts and the hydroelectric portion of the Capacity Refurbishment Variance Account and provide the rate impacts by customer class.

Response

a) The requested table, recast assuming a 24-month recovery period for the December 31, 2012 forecast balances provided in the pre-filed evidence for the Hydroelectric Incentive Mechanism Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account and the regulated hydroelectric portion of the Capacity Refurbishment Variance Account, is attached as Table 1. As can be seen in the table this change would increase the Hydroelectric Payment Rider from 2.60 $/MWh (Ex. H1-1-2, Table 16) to 2.68 $/MWh. The effects of this change on typical customer bill impacts are very small as shown in Table 2.

Numbers may not add due to rounding.

Table 1 (Re-cast of H1-2-1 Table 1)

Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	17.1	17.1	24	8.6	8.6	17.1	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	34.0	24	17.0	17.0	34.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	(2.4)	24	(1.2)	(1.2)	(2.4)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	4.1	24	2.1	2.1	4.1	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(2.5)	24	(1.3)	(1.3)	(2.5)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	1.1	24	0.6	0.6	1.1	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	15.1	15.1	48	3.8	3.8	7.6	7.6
9	**Impact for USGAAP Deferral - Hydroelectric**	2.8	2.8	24	1.4	1.4	2.8	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	(3.9)	24	(1.9)	(1.9)	(3.9)	0.0
11	**Total** (lines 1 though 10)	113.8	113.8		53.1	53.1	106.3	7.6
12	**Total Approved 2011-2012 Production[4] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.68	

Notes:

1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for lines 3, 4 and 7. See Ex. H1-1-1 Sections 4.4 and 5.5.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Table 2
Typical Consumer Bill Impact

Line No.	Description	Residential	Medium / Large Business	Large Industrial
1	**Typical Consumption[1] (kWh/Month)**	842	155,640	4,584,150
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409	75,623	2,227,363
3	**Typical Bill[1] ($/Month)**	116.30	19,740	558,968
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**1.67**	**309**	**9,101**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**1.4%**	**1.6%**	**1.6%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77		
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	53.86		
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	4.09		
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	8%		
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8		
11	Forecast of Provincial Demand[3] (TWh)	285.6		
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%		

Notes:

1 For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills.
For Medium/Large Business consumers, OPG has used average monthly consumption of 150,000 kWh and an average bill of $19,740 as used in Toronto Hydro's 2012 IRM application (EB-2012-0064) bill impact tables (Tab 3, Schedule C2.2, General Service > 50 kW < 1000 kW).
For Large Industrial consumers, OPG has used average monthly consumption of 4,500,000 kWh and an average bill of $558,968 as used in Toronto Hydro's 2012 IRM application (EB-2012-0064) bill impact tables (Tab 3, Schedule C2.2, Large User).
Typical Consumption for each customer class includes line losses.

2 See L-3-5 EP-02

3 Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).

AMPCO Interrogatory #16

Ref: Exhibit I1-1-2 Page 1 Lines 1-167

Issue Number: 3
Issue: Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Interrogatory

a) Please provide bill impact analysis for all customer classes, with supporting calculations.

Response

Please see Attachment 1, Table 1.

OPG as a wholesale generator does not have customer classes and thus does not have customer class data. In addition to the residential consumer analysis previously provided, the attached Table 1 shows calculations for “Medium/Large Business” and “Large Industrial” consumers using information from Toronto Hydro’s recent application (EB-2012-0064) for monthly consumption and bill data for these two customer groups as noted in Footnote 1 to Table 1. To calculate bill impacts for these customer groups, OPG applied the same methodology used for residential consumers.

Numbers may not add due to rounding.

Table 1
Typical Consumer Bill Impact

Line No.	Description	Residential	Medium / Large Business	Large Industrial
1	**Typical Consumption[1] (kWh/Month)**	842	155,640	4,584,150
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409	75,623	2,227,363
3	**Typical Bill[1] ($/Month)**	116.30	19,740	558,968
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**1.66**	**307**	**9,055**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**1.4%**	**1.6%**	**1.6%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77		
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	53.84		
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	4.07		
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	8%		
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8		
11	Forecast of Provincial Demand[3] (TWh)	285.6		
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%		

Notes:

1. For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills.
   For Medium/Large Business consumers, OPG has used average monthly consumption of 150,000 kWh and an average bill of $19,740 as used in Toronto Hydro's 2012 IRM application (EB-2012-0064) bill impact tables (Tab 3, Schedule C2.2, General Service > 50 kW < 1000 kW).
   For Large Industrial consumers, OPG has used average monthly consumption of 4,500,000 kWh and an average bill of $558,968 as used in Toronto Hydro's 2012 IRM application (EB-2012-0064) bill impact tables (Tab 3, Schedule C2.2, Large User).
   Typical Consumption for each customer class includes line losses.
2. See L-3-5 EP-02
3. Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).

CME Interrogatory #01

Ref: Exhibit I, Tab 1, Schedule 2, page 1, Rate & Consumer Impact
Exhibit I, Tabs 1, 2 and 3

Issue Number: 3
Issue: Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Interrogatory

1**.** In order to help stakeholders gain a high level appreciation of the full potential rate and consumer impacts of all unrecovered accumulations in all of OPG's Deferral and Variance Accounts at December 31, 2012, CME seeks the following information:

(a) Do the amounts of $104.5M for Regulated Hydroelectric and $1,218.1M for Nuclear represent all unrecovered balances in all of OPG's Deferral and Variance Accounts at December 31, 2012?

(b) If not, then what are the amounts for Regulated Hydroelectric and Nuclear that represent all unrecovered balances in all of OPG's Deferral and Variance Accounts at December 31, 2012?

(c) Assume that all of the unrecovered balances in all of OPG's Deferral and Variance Accounts at December 31, 2012, are cleared to customers by way of a one-time charge, with an effective payment date in either the first quarter or second quarter of 2013. Under that assumption, please provide the following information:

- (i) What would the one-time charge be, expressed in $ per MWh, for the clearance of all balances in all of OPG's Regulated Hydroelectric, Deferral and Variance Accounts at December 31, 2012, compared to the amount of $2.42/MWh that OPG is proposing?
- (ii) What would the one-time charge be expressed in dollars per mWh to clear all balances at December 31, 2012, in all of OPG's Nuclear Deferral and Variance Accounts compared to the amount of $8.51/MWh that OPG is proposing?
- (iii) What would each of the charges expressed in $ per MWh be for Regulated Hydroelectric and Nuclear if the recovery was spread out over twelve (12) months from January 1 to December 31, 2013?
- (iv) Please express the combination of the one-time charges for Regulated Hydroelectric and Nuclear to be provided in response to questions (i) and (ii) above as a percentage of the annual bill of the typical residential consumer described at Exhibit I, Tab 1, Schedule 2.
- (v) Please express the combined Regulated Hydroelectric and Nuclear charges to be provided in response to question (iii) above as a percentage increase in the monthly bill of the typical residential consumer described at Exhibit I, Tab 1, Schedule 2.

(d) What are the approximate levels of incremental accumulations that OPG anticipates will occur in its Regulated Hydroelectric and Nuclear Deferral and Variance Accounts in 2013 and beyond? Are annual incremental debit accumulations in 2013 and beyond likely to be in the hundreds of millions of dollars as they have been in prior years?

Response

a) No. As noted at Ex. A2-1-1, p. 1, lines 20-30 and further discussed in Ex. H1-1-1, sections 4.4 and 5.5, OPG's Application proposes to defer the clearance of balances in the Hydroelectric Incentive Mechanism Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account and the hydroelectric portion of the Capacity Refurbishment Variance Account.

b) As provided in the updated evidence at Ex. H1-1-2, Table 1, col. (d), line 12 and Ex. H1-1-2, Table 16, col. (a), line 11 for regulated hydroelectric and Ex. H1-1-2 Table 1, col. (d), line 27 and Ex. H1-1-2, Table 17, col. (a), line 11 for nuclear, the total unrecovered forecast balances in OPG's deferral and variance accounts as at December 31, 2012 are $113.8M and $1,160.5M, respectively.

c) (i) In preparing this response, OPG understands "one-time charge ... expressed in $ per MWh" to mean a charge applied to a single month's settlement. Based on this understanding, and using the same production forecast underpinning proposed calculation of riders, the one-time charge required to clear total projected December 31, 2012 balances in the Hydroelectric deferral and variance accounts would be $68.81/MWh, calculated as follows:

$113.8 M / (39.7 TWh / 24 months) = $68.81 / MWh

(ii) Based on the same understanding as described in response c) (i), above, the one-time charge required to clear total projected December 31, 2012 balances in the Nuclear deferral and variance accounts would be $273.34/MWh, calculated as follows:

$1,160.5 M / (101.9 TWh / 24 months) = $273.34 / MWh

(iii) The regulated hydroelectric and nuclear rate riders calculated using forecast balances in all of OPG's deferral and variance accounts as at December 31, 2012, as provided in col. (a) of Ex. H1-2-1, Tables 1 and 2, respectively, would be $5.73/MWh and $22.78/MWh, respectively, assuming a 12-month recovery period of January 1 to December 31, 2013 for all balances.

(iv) As estimated in the same manner as described in Ex. I1-1-2, the resulting increase would be approximately $88.40 for a single month, which is 6.3 per cent of the annual bill of a typical residential consumer with a monthly bill of $116.30.

(v) As estimated in the same manner as described in Ex. I1-1-2, the resulting increase would be approximately $6.28 per month, or 5.4 per cent, on a typical monthly residential consumer bill of $116.30. At the January 23, 2013 Technical Conference, an undertaking (JT1.2) was given providing the calculations of the figures in this portion of the response. As such, Attachment 1 has been added to this updated response showing updated calculations in the same form as Attachment 1 to JT1.2.

d) OPG estimates projected incremental debit accumulations for the regulated hydroelectric and nuclear deferral and variance accounts for 2013 at levels of approximately $100M and $700M, respectively. OPG declines to provide any such projected estimates for years beyond 2013 as the information is not relevant to the clearance of the 2012 audited actual account balances.

Numbers may not add due to rounding.

Table 1
Computation of Percent Change in Payment Amounts Resulting from L-3-3 CME-01, 1, (c), (iii)
EB-2010-0008 to EB-2012-0002

Line No.	Description	Notes	EB-2010-0008 Board Approved Payment Amounts	EB-2012-0002 Payment Amounts Resulting from L-3-3 CME-01, 1, (c), (iii)	Percent Change in Payment Amounts
			(a)	(b)	(c)
	PERCENT CHANGE IN PAYMENT AMOUNTS				
	AVERAGE RATE:				
1	**Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	34.13	41.51	22%
2	**Nuclear Rate Including Rider ($/MWh)**	2	55.85	74.30	33%
3	**Approved 2011-12 Regulated Hydroelectric Production (TWh)**	3	39.7	39.7	
4	**Approved 2011-12 Nuclear Production (TWh)**	3	101.9	101.9	
5	**Total Approved 2011-12 Production (TWh)** (line 3 + line 4)		141.6	141.6	
6	**Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 3 / line 5)		9.57	11.64	
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		40.19	53.47	
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		49.77	65.11	
9	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2010-0008 TO EB-2012-0002**				**31%**
	(((line 8 col. (b) - line 8 col. (a)) / line 8 col. (a))/100)				

Notes:

1 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus proposed Regulated Hydroelectric rider of 5.73 $/MWh from updated response to L-3-3 CME-01, 1.(c)(iii).

2 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus proposed nuclear rider of 22.78 $/MWh from updated response to L-3-3 CME-01, 1.(c)(iii).

3 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Table 2

Typical Consumer Bill Impact Resulting from L-3-3 CME-01, 1, (c), (iii)

Line No.	Description	Residential
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409
3	**Typical Bill[1] ($/Month)**	116.30
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**6.28**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**5.4%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	65.11
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	15.34
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	31%
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8
11	Forecast of Provincial Demand[3] (TWh)	285.6
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%

Notes:

1 For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills. Typical Consumption includes line losses.

2 See L-3-5 EP-02

3 Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).

`

Board Staff Interrogatory #32

Ref: OPG Application for USGAAP Deferral Account (EB-2011-0432), page 5
Exh A3-1-2 page 8

Issue Number: 6
Issue: Is the request to adopt USGAAP for regulatory accounting, reporting and rate-making purposes appropriate?

Interrogatory

At page 5 of OPG's application for a USGAAP deferral account, it states that, "OPG would have been required to seek OEB approval of regulatory assets in excess of $2 billion in order to address the financial impacts from the adoption of IFRS." In the current application at page 8, it states that the cumulative impact of IFRS would be $3.9 billion. Please explain the reasons for the difference in the estimated impact filed on December 29, 2011 and that filed on September 24, 2012.

Response

The difference is explained at Ex. A3-1-2, page 8, footnote 3.

The amount in excess of $2 billion cited in EB-2011-0432 reflected an estimate of the regulated portion of the actual previously unamortized amounts as at January 1, 2011. The projected increase in the previously unamortized amounts is due to additional net actuarial losses actually incurred during 2011 and expected to be incurred during 2012.