Board Staff Interrogatory #01

Ref: Exh H1-1-1 page 4

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

Interrogatory

The pre-filed evidence states that one of the contributing factors to the variance in the Ancillary Services Net Revenue Variance Account – Hydroelectric is the "…lower than expected automatic generation control revenues due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck Pump Generating Station ("PGS") under O. Reg. 429/04 as amended…"

a) With respect to the Global Adjustment charge associated with the use of the PGS, please provide reference to the specific sections of O. Reg. 429/04 that were amended and when the amendment was effective.

b) Please provide the calculation of the impact in 2011 and 2012 due to the elimination of the Global Adjustment charge.

Response

a) The Global Adjustment charge associated with the use of the Sir Adam Beck Pump Generating Station ("PGS") is described in O. Reg. 429/04, Part III (Adjustments) Section 5, Subsection (2)(a) and Section 11, Subsection (3)(a). The amendment was effective January 1, 2011.

b) For 2012, OPG forecasts automatic generation control ("AGC") revenues to be lower by approximately $5.4M due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck PGS. For 2011, OPG calculates AGC revenues to be lower by approximately $3.6M due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck PGS.

Board Staff Interrogatory #02

Ref: Exh A3-1-1 Attachment 1
Exh H2-1-1 Table 1

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

Interrogatory

OPG's 2011 Annual Report (page 75) states, "The most recent update of the estimate for the Nuclear Liabilities was performed as at December 31, 2011 and resulted in a $934 million increase to OPG's liabilities, and a corresponding increase in the carrying value of the nuclear generating stations to which the liabilities relate."

The current approved ONFA Reference Plan covers the period from 2012 to 2016 and was approved by the Province effective on January 1, 2012.

a) Please explain the relationship between the ONFA Reference Plan created funds for OPG's nuclear programs and OPG's nuclear liabilities, and how the changes to the funds/funding as required by the reference plan create impacts on the nuclear liabilities (or vice versa).

b) Please explain the accounting basis upon which changes arising from the ONFA Reference Plan effective January 1, 2012 were recognized and recorded in the 2011 financial statements (e.g., "Property, plant and equipment" and "Fixed asset removal and nuclear waste management" line items in the consolidated balance sheets, etc.) given that the effective date of the current ONFA Reference Plan is January 1, 2012.

c) Board staff notes that the Darlington ARO refurbishment adjustment amount of $497M (Exh. H2-1-1, Table 1) which was effective January 1, 2010 was added to the adjusted opening balance in 2010. Please explain why accounting changes related to the ONFA Reference Plan effective January 1, 2012 are not reflected as adjustments to the 2012 opening balance sheets and therefore the starting point of the 2012 calculations applicable to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

Response

a) The ONFA Reference Plan contains all the relevant information, including major planning assumptions and associated cost estimates, necessary to derive ONFA lifecycle liabilities for managing nuclear waste and decommissioning for each of OPG's stations and waste management facilities. "Lifecycle" means that the ONFA liabilities are calculated to take into account all future waste (used fuel and low and intermediate level waste) to be produced by OPG-owned nuclear generating stations to the end of their assumed lives. The funding requirements (contributions into the segregated funds) under the ONFA are developed based on these lifecycle liabilities using an approved discount rate as per the ONFA.

OPG's nuclear liabilities (asset retirement obligation) as reported in OPG's consolidated financial statements are determined in accordance with generally accepted accounting principles ("GAAP"). These liabilities are measured at a point in time and do not take into account applicable waste that has not been generated to date. Specifically, the liabilities represent the present value of the escalated cash flows from cost estimates, taking into account only applicable waste produced by OPG-owned nuclear generating stations to the end of the current financial reporting year rather than over their entire lifecycle. The discount rate used to determine the accounting liabilities is determined in accordance with GAAP, rather than the ONFA, as discussed in response to interrogatory L-2-1 Staff 20 (a).

Under the ONFA, cost estimates and planning assumptions are required to be updated typically on a five-year cycle. Contributions to the ONFA funds are required to be amended based on the updated cost estimates and planning assumptions. OPG's nuclear liabilities for accounting purposes are to be revised when a change in management's best estimate occurs, based on having sufficient confidence around the updated estimate. Changes in cost estimates as part of the ONFA Reference Plan update process have formed the basis of a change in management's best estimate which, when sufficient confidence is achieved, results in updates to the accounting liabilities.

In summary, changes to the ONFA cost estimates and planning assumptions impact both ONFA funding requirements and OPG's nuclear liabilities for financial reporting purposes.

b) and c) The timing of recognition of adjustments to the ARO is a result of the timing of OPG achieving sufficient confidence, in the context of specific events and circumstances surrounding the adjustment, that results in a change in management's best estimate of the liabilities. CICA Handbook Section 3110, *Asset Retirement Obligations,* within paragraph .07, states specifically that all ARO must be recognized when a reasonable estimate of their fair value can be made.

In the case of the ARO adjustment arising from the 2012 ONFA Reference Plan update, the requisite confidence was obtained by OPG in late 2011, not 2012. This confidence was obtained through receiving indication from the Ontario Financing Authority ("OFA"), in late 2011, that OPG had appropriately supported the planning assumptions and other aspects of its final 2012 ONFA Reference Plan submission and had satisfactorily addressed the OFA's inquiries. Based on this indication, OPG concluded that the cost estimates reflected in the final 2012 ONFA Reference Plan submission were unlikely to change and, therefore, represented management's best estimate underlying the nuclear liabilities as at December 31, 2011.

In the case of the ARO adjustment as a result of the decision to proceed with the definition phase of the Darlington refurbishment, OPG obtained the requisite confidence, for accounting purposes, in early 2010 that the definition phase of the project would proceed and, therefore, extended the estimated average service life, for depreciation purposes, of the Darlington station and recognized the related ARO adjustment in 2010. As noted in EB-2010-0008, Ex. F4-1-1, section 3.1, this confidence resulted in the extension of the service life being effective January 1, 2010, based on three considerations, one of which was "the approval of management's recommendation to proceed with the definition phase of the refurbishment project for Darlington by OPG Board in November 2009 and the concurrence by the Province <u>during January 2010</u> and publicly announced <u>in February 2010</u>." [emphasis added]

It should be noted that, even if the ARO/ARC adjustment related to the 2012 ONFA Reference Plan was recognized in the 2012 opening balance sheet rather than at December 31, 2011, the 2012 additions to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account would be the same. This would be the case because there were no immediate impacts on expense / revenue requirement items recorded in these accounts (e.g., depreciation expense, variable used fuel and waste management expenses, return on rate base, accretion expense, income taxes) on the date of recognition of the ARO adjustment. On the date of recognition, the only impact of the ARO adjustment was the corresponding change in the ARC. In contrast, the impacts on the items recorded in the two accounts arise with the passage of time (i.e., during 2012) as they represent income statement items / period revenue requirement impacts.

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 #04

Ref: Exh H2-1-1 Table 3

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

Interrogatory

Table 3 lists amounts associated with each of the five nuclear programs (under Description line items row #'s 1 to 12) in relation to each nuclear station (under Prescribed Facilities columns a to c and Bruce Facilities columns e and f).

a) Please provide detailed calculations, including all inputs and assumptions, showing and explaining how these amounts were derived.

b) What methodology was used to attribute and allocate these costs to each station unit and how was it applied?

c) What is the probability of significant differences (or range of probability outcomes) in estimating these amounts based on the inputs and assumptions in the ONFA Reference Plan effective January 1, 2012?

d) Was any sensitivity analysis performed to determine whether the results and impacts were reasonable and acceptable, and if so, what was the methodology used and the results of this analysis?

Response

a) The actual asset retirement obligation ("ARO") adjustment at the end of 2011 and that projected at the end of 2012 associated with each of the five nuclear programs (under Description line items rows 1 to 5 and 8 to 12 in Ex. H2-1-1, Table 3) in relation to each nuclear station were derived as described below.

Actual 2011 ARO Adjustment

Assumptions:

1) Base line cost estimates are from the approved 2012 ONFA Reference Plan.
2) Estimated assumed station end-of-life dates are based on the approved 2011 Depreciation Review Recommendations (L-2-1 Staff-19 Attachment 2).
3) Nuclear waste volume forecast consistent with assumed station end-of-life dates.

The calculation starts with the unadjusted value of the nuclear liabilities as at December 31, 2011, which is based on undiscounted estimated cash flows and assumptions per the approved 2006 ONFA Reference Plan incorporating the 2010 Darlington Refurbishment adjustment (discussed in EB-2010-0008 Ex. C2-1-2, section 4.1) taking into account only applicable waste produced to date, by program. Using the updated assumptions above, the applicable undiscounted estimated cash flows are recalculated, by program. The present value of the net change in the undiscounted estimated cash flows, as shown by program in Ex. H2-1-1, Table 3, represents the $934.3M net increase in the total ARO recognized at December 31, 2011, as shown by station at line 6 of that table. In accordance with CGAAP, the net increase of $934.3M was calculated using a credit-adjusted risk-free rate of 3.43 per cent.

As described in EB-2010-0008 Ex. C2-1-2, section 3.1, the change in the ARO is accompanied by a corresponding change in the net book value of the assets to which the ARO relates, which is the asset retirement cost (“ARC”). The corresponding changes in the ARC, by station, resulting from the $934.3M ARO increase is shown at line 7 of Ex. H2-1-1, Table 3.

<u>Projected 2012 ARO Adjustment</u>

Assumptions:

1) Base line cost estimates are from the approved 2012 ONFA Reference Plan.
2) Estimated assumed station end-of-life dates, reflecting service life extensions for Pickering Units 5-8 and Bruce units at the end of 2012, are as per the approved 2012 ONFA Reference Plan and as shown in the chart in L-2-1 Staff-19 b).
3) Nuclear waste volume forecast consistent with assumed station end-of-life dates.

The calculation starts with the projected unadjusted value of the nuclear liabilities as at December 31, 2012, which is based on undiscounted estimated cash flows and assumptions listed under the Actual 2011 ARO Adjustment, by program. Using the updated assumptions at the end of 2012 above, the applicable undiscounted estimated cash flows are recalculated, by program. The present value of the net change in the undiscounted estimated cash flows, as shown by program in Ex. H2-1-1, Table 3, represents the projected $379.0M net increase in the total ARO projected to be recognized at December 31, 2012, as shown by station at line 13 of that table. In accordance with CGAAP/USGAAP, the projected net increase of $379.0M is calculated using an assumed credit-adjusted risk-free rate of 3.43 per cent. The projected corresponding changes in the ARC, by station, resulting from the $379.0M ARO increase are shown at line 14 of Ex. H1-1-1, Table 3.

b) The same methodology as that reflected in the approved EB-2010-0008 payment amounts is followed to attribute nuclear liability costs for the five decommissioning and waste management programs to the station level:

- Decommissioning and Used Fuel Storage programs: The cost estimates for these two programs are prepared at the station level with individual estimates prepared for each station; therefore no allocation is required.
- Used Fuel Disposal, L&ILW Storage and L&ILW Disposal programs: As these three programs involve central facilities, the cost estimates are prepared at the program level. The costs are allocated to stations based on the lifecycle waste volume forecast underlying the calculation of the liabilities.

ARC is recorded at the station level based on the ARO amounts attributed to each station.

c) and d) During the development of the 2012 ONFA Reference Plan in 2011, OPG prepared an analysis to test the sensitivity of the overall estimated lifecycle liability for each of the decommissioning and waste management programs, to changes in input assumptions. This sensitivity analysis conducted for these programs was not conducted at the station level. This sensitivity analysis was completed in two phases. In the first phase, OPG focused on the three longer-term programs, i.e., Decommissioning, Used Fuel Disposal and L&ILW Disposal, which together make up over 80 per cent of the total estimated ONFA lifecycle liability, and tested the estimates of the liability to changes in specific inputs, such as assumed escalation and discount rates, timing of decommissioning, timing of in-service of the used fuel repository, and costs of the programs. The result of this work provided OPG with an indication of the range of possible values for each of the three major programs' liability estimates.

In the second phase, confidence ranges were developed around the liabilities for each of all five individual programs (i.e., including Used Fuel Storage and L&ILW Storage) as well as the total nuclear waste and decommissioning ONFA lifecycle liability estimate. This was accomplished by developing probability distributions around the key input assumptions for the liability estimates for each program, then applying Monte Carlo simulation techniques to sample the distributions of each of these input variables in order to develop overall probability distributions of the liability estimates for each of the five programs as well as the total nuclear waste and decommissioning liability estimate. The results of this second phase of work showed that there is an 80 per cent confidence that the total nuclear waste and decommissioning lifecycle liability lies between $13.1B (2012$PV) and $20.8B (2012$PV) OPG's point estimate of the total ONFA lifecycle liability is $15.7B (2012$PV).

Board Staff Interrogatory #05

Ref: Exh H2-1-1 Attachment 1

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

Interrogatory

The letter dated June 14, 2012 from the Ontario Financing Authority indicates that the Province in approving the ONFA Reference Plan effective January 1, 2012 is prepared to work with OPG and provide OPG with feedback on its proposed implementation of calculations mandated by ONFA sections 3.6, 3.7, 3.8 and 4.6.

a) Please provide sections 3.6, 3.7, 3.8 and 4.6 and related sections from the ONFA.

b) Please provide a summary of the calculations mandated by ONFA for sections 3.6, 3.7, 3.8 and 4.6 and how they relate and are used in the derivation of the asset retirement obligation and the segregated fund contribution schedule.

c) Please indicate whether OPG received any feedback from the Province regarding these mandated calculations and their implementation.

d) Have all calculations for the ONFA Reference Plan effective January 1, 2012 and their implementation been finalized and approved by the Province?

Response

a) Please refer to Attachment 1.

b) The calculations mandated by sections 3.6, 3.7, 3.8 and 4.6 of ONFA in respect of the approved 2012 ONFA Reference Plan are summarized as follows:
   - Section 3.6 requires OPG to calculate the Used Fuel Fund Amended Payment Schedule based on the approved 2012 ONFA Reference Plan.
   - Section 3.7.1(a) requires OPG to provide the balance of the Used Fuel Fund for the initial 2.23M used fuel bundles based on the market value of the fund assets and a real return of 3.25 per cent plus actual Ontario Consumer Price Index.
   - Section 3.8.2 requires OPG to provide the Approved Cost Estimate based on the approved 2012 ONFA Reference Plan and compare the Adjusted Cost Estimate (April 1, 1999 onwards) attributable to the first 2.23M used fuel bundles based on the 1999 ONFA Reference Plan with the one based on the approved 2012 ONFA Reference Plan.
   - Section 4.6 requires OPG to calculate the Decommissioning Fund Original Payment Schedule based on the approved 2012 ONFA Reference Plan.

OPG will make contributions to the ONFA funds based on the Used Fuel Fund Amended Payment Schedule and the Decommissioning Fund Original Payment Schedule once they are approved. The derivation of OPG's asset retirement obligation is not in any way impacted by the implementation of these calculations, as these sections are used exclusively in the calculation of the Used Fuel Fund Amended Payment Schedule and the Decommissioning Fund Original Payment Schedule and related information.

c) and d)
Discussions with the Province were held as part of developing the mandated calculations and implementation. All calculations mandated by sections 3.6, 3.7, 3.8 and 4.6 of the ONFA have been finalized and submitted by OPG to the Province. The Province has been reviewing these calculations and, to date, has not expressed any concern with their accuracy. OPG is awaiting the approval of these calculations and their implementation.

Attachment 1

3.6 Review of Used Fuel Segregated Fund Payment Obligations

In addition to any other circumstances specifically provided in this Agreement, Original Payment Schedule 3.3, any subsequent Amended Payment Schedule 3.6, and the quarterly Payment obligations thereunder, shall be amended from time to time during the term of this Agreement and replaced with an Amended Payment Schedule 3.6 in accordance with the following:

3.6.1 Requirement to Amend. The amount of the quarterly Payments to the Used Fuel Segregated Fund (as reflected in Original Payment Schedule 3.3 or the then current Amended Payment Schedule 3.6 if Original Payment Schedule 3.3 has been replaced) shall be revised in accordance with the following provisions of this section 3.6 and the procedures in Schedule 3.6.1 each time that (a) a new or amended Reference Plan becomes an Approved Reference Plan, (b) a Decommissioning Segregated Fund Matching Payment is made by the Province to the Used Fuel Segregated Fund, (c) a transfer of assets from the Decommissioning Segregated Fund is made to the Used Fuel Segregated Fund under subsection 4.7.3, (d) a Bruce Extraordinary Payment is paid in full to the Used Fuel Segregated Fund, (e) either OPG or the Province, acting reasonably, makes a determination that the Used Fuel Segregated Fund is subject to tax of any nature whatsoever or, having become subject to such tax, is no longer subject to such tax, whether in whole or in part, (f) the Province approves or is deemed to have approved a CNSC Reconciliation Statement under subsection 7.3.4, or (g) any other payment or contribution is made to the Used Fuel Segregated Fund other than a Payment pursuant to section 3.5 subsections 7.3.5, 9.2.5 or 9.3.4 or a Provincial Payment (each of the events in paragraphs (a) through (g) of this subsection 3.6.1 being a "**Triggering Event**".

3.6.2 Determination of Payments. The nominal quarterly Payments to the Used Fuel Segregated Fund shall be calculated as of the date of a Triggering Event as follows:

(a) Determine Station Amount. The Station Amount to be paid for each Station for each quarter during that Station's Remaining Operating Period shall be determined. Subject to the other paragraphs of this subsection 3.6.2, the "**Station Amount**" for a Station as of the date of a Triggering Event shall be the equal nominal amount for each quarter during the Station's then Remaining Operating Period determined so that the aggregate Present Value of each of those equal quarterly nominal amounts plus the Fair Market Value of the assets of the Used Fuel Segregated Fund notionally allocated to that Station equals the Used Fuel Balance to Complete Cost Estimate notionally allocated to that Station in each case as of the date of the Triggering Event. For greater certainty, a Station Amount can be either a positive or negative amount.

(b) Station Amount Where Limitation Applies. Notwithstanding paragraph 3.6.2(a), if the limitation in paragraph 3.6.2(e) applies, then for the purposes only of determining the amount by which the nominal quarterly Payments shall be less than the nominal quarterly Payments set out in the Original Payment Schedule 3.3, the Station Amount for each Station shall be recalculated: (i) insofar as it relates to the Fair Market Value of assets of the Used Fuel Segregated Fund notionally allocated to Incremental Costs and the portion of the Balance to Complete Cost Estimate notionally allocated to Incremental Costs (in each case in accordance with subsection 9.2.3), in the manner otherwise described in this subsection 3.6.2; and (ii) insofar as it relates to the remaining Fair Market Value of assets of the Used Fuel Segregated Fund and the remaining portion of the Used Fuel Balance to Complete Cost Estimate, as the equal nominal amount for each quarter during the Remaining Operating Period for the Station under the 1999 Reference Plan, determined so that the Present Value of each of those quarterly nominal amounts plus the Fair Market Value of the remaining assets notionally allocated to that Station equals the remaining portion of the Used Fuel Balance to Complete Cost Estimate notionally allocated to that Station. If the application of this paragraph 3.6.2(b) would result in an obligation to make any Payments on any date prior to January 1, 2020 which exceed the nominal quarterly Payments set out in Original Payment Schedule 3.3, then notwithstanding this subsection 3.6.2, the nominal quarterly Payments payable on any such date shall be as set out in Original Payment Schedule 3.3. This paragraph 3.6.2(b) shall not apply in respect of Payments calculated for any period on or after January 1, 2020.

(c) Aggregate Quarterly Payments and Right to Net. The nominal quarterly Payment to the Used Fuel Segregated Fund shall equal the aggregate of the Station Amounts for each Station. For greater certainty, if the Station Amount for any Station is a negative amount because the Fair Market Value of the assets of the Used Fuel Segregated Fund notionally allocated to that Station exceeds the portion of the Used Fuel Balance to Complete Cost Estimate notionally allocated to that Station, the Station Amount for that Station shall be calculated as a negative amount which may be deducted or netted against other amounts in determining the aggregate quarterly Payment to the Used Fuel Segregated Fund. The resultant nominal quarterly Payments shall be set out in a new or revised Amended Payment Schedule 3.6 which, subject to paragraph 3.6.2(e), shall replace the then current Original Payment Schedule 3.3 or Amended Payment Schedule 3.6 as the case may be. Notwithstanding the above, the aggregate nominal quarterly Payment cannot be less than nil.

(d) Tax Over-Contribution. Notwithstanding paragraph 3.6.2(e), to the extent that:

(i) OPG or any OPG Nuclear Subsidiary has at any time made any over-contribution to the Used Fuel Segregated Fund by virtue of Payments being previously determined on the basis that the Used Fuel Segregated Fund is subject to tax of any nature or of any amount; or

(ii) a Tax Payment is transferred or paid to the Used Fuel Segregated Fund in accordance with paragraph 4.7.3(c), then the amount of such over-contribution or Tax Payment plus interest on the balance thereof (after giving effect to the following provisions of this paragraph 3.6.2(d)) at a rate equal to the Used Fuel Segregated Fund Rate of Return (for the period of time commencing on the date of each over-contribution or the date on which the Tax Payment is paid or transferred into the Used Fuel Segregated Fund, as applicable, and ending on the date that such over-contribution or Tax Payment to which such interest relates has been applied to reduce the nominal quarterly Payments) shall be applied to reduce the nominal quarterly Payments to the Used Fuel Segregated Fund next falling due until such time as the amount of such over-contribution or Tax Payment, as applicable, and interest, have been exhausted.

(e) Limitation. Notwithstanding paragraphs 3.6.2(a) and 3.6.2(c), but subject to paragraph 3.6.2(d), the nominal quarterly Payments to the Used Fuel Segregated Fund may not be less than (but may be equal to) the nominal quarterly amounts set out in Original Payment Schedule 3.3, except in accordance with the following:

(i) if (and for so long as) the Present Value Threshold Percentage is less than 60%, then the quarterly Payments to the Used Fuel Segregated Fund shall never be less than the nominal quarterly Payments set out in Original Payment Schedule 3.3;

(ii) if (and for so long as) the Present Value Threshold Percentage is equal to or greater than 60%, but less than 70% and the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c) would be less than the nominal quarterly Payments set out in Original Payment Schedule 3.3, then the nominal quarterly Payments to the Used Fuel Segregated Fund shall be those nominal quarterly Payments set out in Original Payment Schedule 3.3 less 25% of the amount, if any, by which the nominal quarterly Payments set out in Original Payment Schedule 3.3 exceeds the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c);

(iii) if (and for so long as) the Present Value Threshold Percentage is equal to or greater than 70%, but less than 80% and the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c) would be less than the nominal quarterly Payments set out in Original Payment Schedule 3.3, then the nominal quarterly Payments to the Used Fuel Segregated Fund shall be those nominal quarterly Payments set out in Original Payment Schedule 3.3 less 50% of the amount, if any, by which the nominal quarterly Payments set out in Original Payment Schedule 3.3 exceeds the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c);

(iv) if (and for so long as) the Present Value Threshold Percentage is equal to or greater than 80%, but less than 90% and the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c) would be less than the nominal quarterly Payments set out in Original Payment Schedule 3.3, then the nominal quarterly Payments to the Used Fuel Segregated Fund shall be those nominal quarterly Payments set out in Original Payment Schedule 3.3 less 75% of the amount, if any, by which those nominal quarterly Payments set out in Original Payment Schedule 3.3 exceeds the nominal quarterly Payments calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c); and

(v) if (and for so long as) the Present Value Threshold Percentage is equal to or greater than 90%, then the nominal quarterly Payments shall be those calculated pursuant to paragraphs 3.6.2(a) and 3.6.2(c).

(f) Assets to be Taken into Account. For purpose of determining a Station Amount, the assets of the Used Fuel Segregated Fund as of the date of a Triggering Event shall first be adjusted to give effect to: (i) any Provincial Payment required to be made under paragraphs 3.8.3(a), (b) or (c) or 3.10.3(b) as of the date of that Triggering Event whether or not such payment has been made; (ii) any reimbursement to the Province of any payment required pursuant to subsection 7.4.1 in respect of an activity required or permitted to be funded from the Used Fuel Segregated Fund and of any over-contribution required pursuant to paragraph 3.8.3(g) as at that Triggering Event, in each case whether or not such reimbursement has actually been made; (iii) any Payments deemed to be made to the Used Fuel Segregated Fund pursuant to paragraphs 3.7.1(d) or 3.8.3(g) or subsection 7.4.1 as of that Triggering Event notwithstanding that OPG may have paid the amount to the Province; and (iv) any payment to or from the Used Fuel Segregated Fund which will be required pursuant to paragraph 3.7.1(b) as of that Triggering Event even if such payment has not been made.

(g) Allocation of Value of Assets. For purposes of the determination of Payments pursuant to this Agreement only, the Fair Market Value of the assets of the Used Fuel Segregated Fund shall be notionally allocated among the Stations at any time in accordance with the following:

(i) The initial Payment made by OPG pursuant to subsection 3.4.1 shall be notionally allocated among the Stations as set out in Original Payment Schedule 3.3.

(ii) Each Payment pursuant to Original Payment Schedule 3.3 or an Amended Payment Schedule 3.6 shall be notionally allocated to each Station *pro rata* to the Station Amounts for each Station included in such Payment. For this purpose and for greater certainty, any payments made by OPG and the OPG Nuclear Subsidiaries to the Province pursuant to paragraphs 3.7.1(d), 3.8.3(g) or subsection 7.4.1 shall be notionally allocated to each Station as if the payments had been made to the Used Fuel Segregated Fund.

(iii) Provincial Payments, Decommissioning Segregated Fund Matching Payments, assets transferred from the Decommissioning Segregated Fund, Bruce Extraordinary Payments and any other payment or contribution made to the Used Fuel Segregated Fund other than a Payment pursuant to Original Payment Schedule 3.3 or an Amended Payment Schedule 3.6 shall be notionally allocated among the Stations *pro rata* to the amount, if any, by which the Used Fuel Balance to Complete Cost Estimate notionally allocated to each Station exceeds the Fair Market Value of the assets of the Used Fuel Segregated Fund notionally allocated to such Station, in each case as of the time of the payment or contribution and in accordance with the then current Approved Reference Plan.

(iv) It shall be assumed that all assets of the Used Fuel Segregated Fund earn a rate of return equal to the Discount Rate regardless of the actual rate of return earned on those assets and that such earning will be allocated to each Station in the same manner as the related assets are allocated pursuant to this section 3.6.

(h) Allocation of Used Fuel Balance to Complete Cost Estimate and Used Fuel Cost Estimate. For purposes of the determination of Payments pursuant to this Agreement only, the Used Fuel Balance to Complete Cost Estimate and the Used Fuel Cost Estimate shall be notionally allocated among the Stations at any time in accordance with the then current Approved Reference Plan.

(i) Allocation of Disbursements. For purposes of the determination of Payments pursuant to the Agreement only, Disbursements from the Used Fuel Segregated Fund in any calendar year shall, notwithstanding how the Disbursement may have actually been expended, be notionally allocated among the Stations *pro rata* to that calendar year's portion of the Used Fuel Cost Estimate notionally allocated to each Station for such calendar year, in accordance with the then current Approved Reference Plan.

3.6.3 Remaining Operating Period.

(a) If a new or amended Reference Plan becomes an Approved Reference Plan more than five (5) years prior to the Operating Period End Date for a Station as contained in the previous Approved Reference Plan and such Station has Permanently Shutdown or the Operating Period End Date in the new Approved Reference Plan is earlier than the Operating Period End Date contained in the previous Approved Reference Plan, then the Remaining Operating Period for that Station shall be the greater of (i) five (5) years from the date of the new Approved Reference Plan and (ii) Remaining Operating Period for such Station in the new Approved Reference Plan.

(b) If a new or amended Reference Plan becomes an Approved Reference Plan fewer than five (5) years prior to the Operating Period End Date for a Station as contained in the previous Approved Reference Plan, then the Remaining Operating Period for such Station shall be the Remaining Operating Period for such Station under the immediately preceding Approved Reference Plan.

(c) If a Triggering Event occurs after a Station has Permanently Shutdown and the Fair Market Value of the assets notionally allocated to that Station is not equal to the portion of the Used Fuel Balance to Complete Cost Estimate then notionally allocated to that Station, the Remaining Operating Period for that Station shall be deemed to be five (5) years from the date of the Triggering Event.

(d) If (i) the amount, if any, as at the date of a Triggering Event, by which the Used Fuel Balance to Complete Cost Estimate notionally allocated to Incremental Costs exceeds the Fair Market Value of the assets notionally allocated to Incremental Costs (in each case in accordance with subsection 9.2.3) under the then current Approved Reference Plan, is greater than such excess amount as at the date of a Triggering Event under the immediately preceding Approved Reference Plan or (ii) the

Adjusted Cost Estimate under the then current Approved Reference Plan is greater than the Adjusted Cost Estimate under the immediately preceding Approved Reference Plan, then, in either such case, the Remaining Operating Period for each Station shall be the greater of (A) the Remaining Operating Period for that Station under the then current Approved Reference Plan and (B) five (5) years from the date of the Triggering Event.

3.7 Adjustment for Used Fuel Segregated Fund Rate of Return

3.7.1 Provincial Adjustment for Non-Incremental Used Fuel Segregated Fund Rate of Return.

(a) Concurrent with the preparation of an Amended Payment Schedule 3.6, OPG shall prepare and submit a written report to the Province setting out OPG's estimate of the amount of the Actual Used Fuel Fund Value and the Fixed Used Fuel Fund Value, as of the day immediately before the most recent Triggering Event (the "**Valuation Date**"). The "**Actual Used Fuel Fund Value**" for any Valuation Date means the Fair Market Value of the assets in the Used Fuel Segregated Fund as of that date. The **"Fixed Used Fuel Fund Value"** for any Valuation Date means the aggregate of (i) the value the Used Fuel Segregated Fund would have had had the assets in the Used Fuel Segregated Fund earned a rate of return equal to the Discount Rate during the period commencing on the date on which the conditions precedent set out in subsection 8.1.2 are satisfied or waived and ending on the Valuation Date, plus (ii) the aggregate Present Value of (A) all brokerage fees paid in respect of the Used Fuel Segregated Fund, (B) fees paid or then payable to the Used Fuel Segregated Fund Managers or Used Fuel Segregated Fund Custodian, provided they are, where relating to a service shared among the Segregated Funds, reasonably allocated among the Segregated Funds, and (C) fees paid or then payable to any other Person which are Used Fuel Eligible Costs pursuant to paragraph 3.1.1(f). For greater certainty, services relating to custodianship of a Segregated Fund include fees for transaction processing, income processing, administration, performance measurement and accounting services for the Segregated Fund but exclude any Disbursement costs (other than the costs of paying the Disbursements as such) charged by any Person other than the Segregated Fund Custodian or its agent or agents. For purposes of determining the Actual Used Fuel Fund Value and the Fixed Used Fuel Fund Value, all assets transferred to the Used Fuel Segregated Fund from the Decommissioning Segregated Fund and any Decommissioning Segregated Fund Matching Payment made by the Province at that time shall for greater certainty be included as assets of the Used Fuel Segregated Fund, but all amounts allocated to Incremental Costs in accordance with subsection 9.2.3 and all assets transferred to the Decommissioning Segregated Fund from the Used Fuel Segregated Fund shall be excluded from the assets of the Used Fuel Segregated Fund. Notwithstanding the foregoing, all Provincial Payments previously made by the Province under subparagraph 3.7.1(b)(ii) shall be included in the assets of the Used Fuel Segregated Fund for the purposes of determining the Actual Used Fuel Fund Value and excluded from the assets of the Used Fuel Segregated Fund for the purposes of determining the Fixed Used Fuel Fund Value. In addition, the determination of the Fixed Used Fuel Fund Value shall take into account each of the timing and amount of the Disbursements out of the

Used Fuel Segregated Fund, other than Disbursements to pay Incremental Costs.

(b) After receipt by the Province of the report referred to in paragraph 3.7.1(a) and all supporting documentation in respect thereof reasonably requested by it from OPG, and after the Actual Used Fuel Fund Value and the Fixed Used Fuel Fund Value in question have either been agreed to by OPG and the Province or any Dispute or Financial Issue in respect thereof has been determined under the provisions of Article 11 or Schedule 11.2:

(i) the Province may direct the Used Fuel Segregated Fund Custodian to make a Disbursement to the Province in any amount up to the amount, if any, by which the Actual Used Fuel Fund Value exceeds the Fixed Used Fuel Fund Value; and

(ii) the Province shall deliver a notice in writing in respect thereof to the Used Fuel Segregated Fund Custodian and immediately make a Provincial Payment to the Used Fuel Segregated Fund equal to the amount, if any, by which the Fixed Used Fuel Fund Value exceeds the Actual Used Fuel Fund Value,

together with interest thereon at the Discount Rate during the period from the applicable Valuation Date to the date of payment. The Province may set off against any Provincial Payment required pursuant to subparagraph 3.7.1(b)(ii), the amount of any Disbursement required to be made to the Province pursuant to any of paragraph 3.7.1(d), paragraph 3.8.3(g) or subsection 7.4.1, in each case to the extent not yet made, without duplication and net of any payments by OPG and the OPG Nuclear Subsidiaries to the Province under any of paragraph 3.7.1(d), paragraph 3.8.3(g) or subsection 7.4.1 which have been applied to reduce the amount of any such required Disbursement.

(c) Subject to any Applicable Law to the contrary, payments required by the Used Fuel Segregated Fund or the Province pursuant to this subsection 3.7.1 may be satisfied by increasing or reducing, as applicable, the undrawn balance on a Provincial Commitment in Lieu.

(d) To the extent that the Disbursements referred to in subparagraph 3.7.1 (b)(i) are prohibited by Applicable Law or the Used Fuel Segregated Fund Custodian otherwise fails for any reason to make such Disbursements to the Province, OPG and the OPG Nuclear Subsidiaries agree to pay the amount of such Disbursement (including for greater certainty applicable interest under paragraph 3.7.1(b) but only up to the amount of Payments next falling due until the amount of such Disbursement is paid to the Province. The Province shall bear the risk that OPG and the OPG Nuclear Subsidiaries are not obligated to make Payments equal to the amount of the Disbursement. The Parties shall require the Used Fuel Segregated Fund Custodian to credit the amount of such payments by OPG to the Province as if such payments had been made as Payments to the Used Fuel Segregated Fund and OPG and the OPG Nuclear Subsidiaries shall be deemed to have discharged their obligations to make such Payments to the extent so paid. However, to the extent Applicable Law does not permit such amounts to be credited against Payments to the Used Fuel Segregated Fund or to the extent compliance with this paragraph 3.7.1(d) does not fully discharge any obligation of OPG and the OPG Nuclear Subsidiaries to make such payments under Applicable Law, OPG and the OPG Nuclear Subsidiaries shall not be obligated to pay such amounts to the Province.

(e) If the Province has, before the 30th day after delivery of the said report and all supporting documentation in respect thereof reasonably requested (and received) by it from OPG, filed a Dispute under Schedule 11.2 or disputes a Financial Issue under subsection 11.1.3 with respect to the report and supporting documentation in respect thereof reasonably requested by the Province under this subsection 3.7.1, any Provincial Payment to the Used Fuel Segregated Fund required under this subsection 3.7.1 shall not be made until a final determination of any such Dispute or Financial Issue has been made. If no such Dispute or Financial Issue has arisen within that period, the Province shall be deemed to have accepted the report.

3.8 Allocation of Liability

The Province agrees to make Provincial Payments, and OPG and the OPG Nuclear Subsidiaries agree to make Payments to the Used Fuel Segregated Fund in accordance with the following provisions of this section 3.8.

3.8.1 Used Fuel Bundle Threshold Limitation on Provincial Payments. The liability of the Province for Provincial Payments under this section 3.8 is based on the assumption that the total number of Used Fuel Bundles discharged and projected to be discharged from all Stations will be 2,230,000 (the Used Fuel Bundle Threshold). OPG and the OPG Nuclear Subsidiaries shall make Payments in accordance with the terms and conditions of this Agreement sufficient to fund the payment of all Incremental Costs.

3.8.2 Calculation of Approved Cost Estimate and Adjusted Cost Estimate. At each time that a new or amended Reference Plan becomes an Approved Reference Plan, OPG shall calculate each of the Approved Cost Estimate and the Adjusted Cost Estimate subject in each case to the approval thereof in writing by the Province, acting reasonably.

3.8.3 Payments and Provincial Payments. The Adjusted Cost Estimate shall be compared to the liability thresholds set out below and the Parties shall comply with the following provisions:

(a) If the Adjusted Cost Estimate exceeds $4.6 billion but is less than or equal to $6.6 billion (each Present Value as of January 1, 1999), the Province shall make Provincial Payments to the Used Fuel Segregated Fund equal to 50% of the amount by which the lesser of:

(i) $6.6 billion; and

(ii) the amount of the Adjusted Cost Estimate;

exceeds $4.6 billion (all amounts, including for greater certainty, the amount of such Provincial Payments, Present Value as of January 1, 1999).

(b) If the Adjusted Cost Estimate exceeds $6.6 billion but is less than or equal to $10.0 billion (each, Present Value as of January 1, 1999), the Province agrees to make Provincial Payments to the Used Fuel Segregated Fund equal to:

(i) the Provincial Payments which would have been required under paragraph 3.8.3(a), being $1.0 billion, and

(ii) 90% of the amount by which the lesser of:

(A) $10.0 billion; and

(B) the amount of the Adjusted Cost Estimate;

exceeds $6.6 billion (all amounts, including for greater certainty, the amount of such Provincial Payments, Present Value as of January 1, 1999).

(c) If the Adjusted Cost Estimate exceeds $10.0 billion (Present Value as of January 1, 1999), the Province agrees to make Provincial Payments to the Used Fuel Segregated Fund equal to the sum of (i) the Provincial Payments which would have been required under paragraph 3.8.3(b), being $4.06 billion and (ii) 100% of the difference between the amount of the Adjusted Cost Estimate and $10.0 billion (all amounts,including for greater certainty, the amount of such Provincial Payments, Present Value as of January 1, 1999).

(d) OPG and the OPG Nuclear Subsidiaries agree to make Payments to the Used Fuel Segregated Fund in accordance with the terms and conditions of this Agreement sufficient to fund the payment of all Used Fuel Eligible Costs in the Adjusted Cost Estimate at the times and in the amounts set out in Original Payment Schedule 3.3 or the then current Amended Payment Schedule 3.6 if Original Payment Schedule 3.3 has been replaced, in all cases after taking into account the Provincial Payments required by this subsection 3.8.3.

(e) The determination from time to time of Amended Payment Schedule 3.6 shall reflect the foregoing provisions of this subsection 3.8.3, without duplication of a Payment already required to be made under Original Payment Schedule 3.3 or an Amended Payment Schedule 3.6.

(f) The Parties acknowledge that to the extent that the Used Fuel Segregated Fund is used to permit OPG and/or the OPG Nuclear Subsidiaries to honour their obligations under any Nuclear Legislation as contemplated by section 3.2, all Incremental Costs resulting from the application of section 3.2 shall be excluded from the operation of the foregoing provisions of this subsection 3.8.3. OPG and the OPG Nuclear Subsidiaries agree to make Payments sufficient to fund in whole all such Incremental Costs at the times and in the amounts provided for in this Agreement, and they acknowledge that neither the Province nor OEFC shall in any circumstances be obligated to fund any portion of such Incremental Costs or to assume any risk of increases in such costs as a result of any change in the provisions (or the enactment of) any Nuclear Legislation or otherwise, save only any payment obligation of the Province as may arise under any Provincial Guarantee.

(g) The Parties acknowledge that circumstances may arise where the Province will have made Provincial Payments to the Used Fuel Segregated Fund in excess of its obligation to do so under the terms of this Agreement. The Province shall have the right as at December 31 in any year during the term of this Agreement to cause OPG to prepare a calculation of any such over-contribution to the Used Fuel Segregated Fund by the Province and to submit such estimate to the Province for its approval. The Province shall review the report and all supporting documentation in respect thereof reasonably requested (and received) by it from OPG and, acting reasonably, approve OPG's calculation, failing which the resulting Financial Issue shall be settled in accordance with subsection 11.1.3. If at any time it is determined that the Province has over-contributed to the Used Fuel Segregated Fund, to the extent that Applicable Law permits such over-contribution (together with interest thereon at the Discount Rate for the period from the date of the over-contribution to the date of repayment to the Province) to be re-paid to the Province out of the Used Fuel Segregated Fund, OPG and the Province agree to cause the Used Fuel Segregated Fund Custodian to make a Disbursement to the Province equal to the amount of the over-contribution (plus interest as aforesaid) within 10 Business Days of the Province making a request therefor in writing, provided that the repayment to the Province may be made in Cash only to the extent of the then Present Value of Cash contributed to the Used Fuel Segregated Fund up to that time by the Province, net of the then Present Value of any repayment to the Province in Cash previously made pursuant to this subsection 3.8.3. Any repayment to the Province not permitted to be made in Cash because of the previous sentence shall be made by reducing the amount of any outstanding Provincial Commitment in Lieu previously contributed to the Used Fuel Segregated Fund. To the extent that such reimbursement is prohibited by Applicable Law or the Used Fuel Segregated Fund Custodian otherwise fails for any reason to reimburse the Province, OPG and the OPG Nuclear Subsidiaries agree to pay the amount of such over-contribution (plus interest as aforesaid) to the Province in Cash, but only up to the amount of Payments next falling due until the amount of such over-contribution (plus interest as aforesaid) is paid to the Province. The Province shall bear the risk that OPG and the OPG Nuclear Subsidiaries are not obligated to make Payments equal to the amount of the over-contribution (plus interest as aforesaid). The Parties shall require the Used Fuel Segregated Fund Custodian to credit the amount of such payments by OPG to the Province as if such payments had been made as Payments to the Used Fuel Segregated Fund and OPG and the OPG Nuclear Subsidiaries shall be deemed to have discharged their obligations to make such Payments to the extent so paid. However, to the extent Applicable Law does not permit such amounts to be credited against Payments to the Used Fuel Segregated Fund or to the extent compliance with this paragraph 3.8.3(g) does not fully discharge any obligation of OPG and the OPG Nuclear Subsidiaries to make such payments under Applicable Law, OPG and the OPG Nuclear Subsidiaries shall not be obligated to pay such amounts to the Province.

(h) The Province may set off against any Provincial Payment required pursuant to subsection 3.8.3 the amount of any Disbursement required to be made to the Province pursuant to any of paragraph 3.7.1(d), paragraph 3.8.3(g) or subsection 7.4.1, in each case to the extent not yet made, without duplication and net of any payments by OPG and the OPG Nuclear Subsidiaries to the Province under any of paragraph 3.7.1(d), paragraph 3.8.3(g) or subsection 7.4.1 which have been applied to reduce the amount of any such required Disbursement.

4.6 Review Decommissioning Segregated Fund Payment Obligations

In addition to any other circumstances specifically provided in this Agreement, Original Payment Schedule 4.6, if and when established, and any subsequent Amended Payment Schedule 4.6 and the quarterly Payment obligations of OPG and the OPG Nuclear Subsidiaries thereunder, shall be established or amended from time to time during the term of this Agreement in accordance with the following:

4.6.1 Requirement to Establish or Amend. The amount of the quarterly Payments to the Decommissioning Segregated Fund (as reflected in Original Payment Schedule 4.6, if and when established, or the then current Amended Payment Schedule 4.6 if Original Payment Schedule 4.6 has been replaced) shall be established or revised in accordance with the following provisions of this section 4.6 and the procedures in Schedule 4.6.1 each time that (a) a new or amended Reference Plan becomes an Approved Reference Plan, (b) either OPG or the Province, acting reasonably, makes a determination that the Decommissioning Segregated Fund is subject to tax of any nature whatsoever or, having become subject to such tax, is no longer subject to such tax, whether in whole or in part, (c) it is determined by OPG, acting reasonably, that during any consecutive 12-month period (with duplication of any such period), the Decommissioning Segregated Fund Rate of Return has been greater than the Discount Rate, (d) the Province approves or is deemed to have approved a CNSC Reconciliation Statement under subsection 7.3.4, or (e) any other payment or contribution is made to the Decommissioning Segregated Fund other than a Payment pursuant to Original Payment Schedule 4.6 or an Amended Payment Schedule 4.6, subsections 7.3.5, 9.2.5 or 9.3.4, a Provincial Payment or the OEFC Payment (each of the events in paragraphs (a) through (e) of this subsection 4.6.1 being a "**Triggering Event**"). The Original Payment Schedule 4.6 shall be established in accordance with the procedures of this section 4.6 and Schedule 4.6.1 at the time that the first Triggering Event occurs.

4.6.2 Determination of Payments. The nominal quarterly Payments to the Decommissioning Segregated Fund shall be calculated as of the date of a Triggering Event as follows:

(a) Determine Station Amount. The Station Amount to be paid for each Station for each quarter during that Station's Remaining Operating Period shall be determined. The "**Station Amount**" for a Station as of the date of a Triggering Event shall be the equal nominal amount for each quarter during the Station's then Remaining Operating Period determined so that the aggregate Present Value of each of those equal quarterly nominal amounts plus the Fair Market Value of the assets of the Decommissioning Segregated Fund notionally allocated to that Station equals the Decommissioning Balance to Complete Cost Estimate notionally allocated to that Station, in each case, as of the date of the Triggering Event. For greater certainty, a Station Amount can be either a positive or negative amount.

(b) Aggregate Quarterly Payments and Right to Net. The nominal quarterly Payment to the Decommissioning Segregated Fund shall equal the aggregate of the Station Amounts for each Station. For greater certainty, if the Station Amount for any Station is a negative amount because the Fair Market Value of the assets of the Decommissioning Segregated Fund notionally allocated to that Station exceeds the portion of the Decommissioning Balance to Complete Cost Estimate notionally allocated to that Station, the Station Amount for that Station shall be calculated as a negative amount which may be deducted or netted against other amounts in determining the aggregate quarterly Payment to the Decommissioning Segregated Fund. The resultant nominal quarterly Payments shall be set out in the Original Payment Schedule 4.6 or a new or revised Amended Payment Schedule 4.6, as applicable, which shall, if such schedule is not the Original Payment Schedule, replace the then current Amended Payment Schedule 4.6 or Original Payment Schedule 4.6, as the case may be. Notwithstanding the above, the aggregate nominal quarterly Payment cannot be less than nil.

(c) Tax Over-Contribution. To the extent OPG or the Nuclear Subsidiaries has at any time made any over-contribution to the Decommissioning Segregated Fund by virtue of Payments being previously determined on the basis that the Decommissioning Segregated Fund is subject to tax of any nature or of any amount, the amount of such over-contribution plus interest on the balance thereof (after giving effect to the following provisions of this paragraph 4.6.2(c)) at a rate equal to the Decommissioning Segregated Fund Rate of Return (for the period of time commencing on the date of each over-contribution and ending on the date that such over-contribution to which such interest relates has been applied to reduce the nominal quarterly Payments) shall be applied to reduce the nominal quarterly Payments to the Decommissioning Segregated Fund next falling due until such time as the amount of such over-contribution and interest has been exhausted.

(d) Assets to be Taken into Account. For the purposes of determining a Station Amount, the assets of the Decommissioning Segregated Fund as of the date of a Triggering Event shall first be adjusted to give effect to: (i) any reimbursement of the Province required pursuant to subsection 7.4.1 in respect of an activity required or permitted to be funded from the Decommissioning Segregated Fund as of that Triggering Event whether or not such reimbursement has actually been made; (ii) any Payments deemed to be made to the Decommissioning Segregated Fund pursuant to subsection 7.4.1 as of that Triggering Event notwithstanding that OPG may have paid the amount to the Province; and (iii) Provincial Payments or OEFC Payments to the Decommissioning Segregated Fund under subsection 4.7.3 required as of that Triggering Event whether or not such payment has actually been made.

(e) Allocation of Value of Assets. For purposes of the determination of Payments pursuant to this Agreement only, the Fair Market Value of the assets of the Decommissioning Segregated Fund shall be notionally allocated among the Stations at any time in accordance with the following:

(i) Each Payment pursuant to Original Payment Schedule 4.6 or an Amended Payment Schedule 4.6 made from time to time shall be notionally allocated to each Station *pro rata* to the Station Amounts for each Station included in such Payment. For greater certainty, any payments by OPG or the OPG Nuclear Subsidiaries to the Province pursuant to subsection 7.4.1 shall be notionally allocated to each Station as if the payments had been made to the Decommissioning Segregated Fund.

(ii) The OEFC Payment, any Provincial Payments, the initial Payment made by OPG pursuant to section 4.5 and any other payment or contribution made to the Decommissioning Segregated Fund other than a Payment pursuant to Original Payment Schedule 4.6 or an Amended Payment Schedule 4.6 shall be notionally allocated among the Stations *pro rata* to the amount if any, by which, the Decommissioning Balance to Complete Cost Estimate notionally allocated to each Station exceeds the Fair Market Value of the assets of the Decommissioning Segregated Fund notionally allocated to such Station, in each case as of the time of the payment or contribution, in accordance with the then current Approved Reference Plan.

(iii) It shall be assumed that all assets of the Decommissioning Segregated Fund earn a rate of return equal to the Discount Rate regardless of the actual rate of return earned on those assets and that such earnings will be allocated to each Station in the same manner as the related assets are allocated pursuant to this section 4.6.

(f) Allocation of Decommissioning Balance to Complete Cost Estimate and Decommissioning Cost Estimate. For purposes of the determination of Payments pursuant to this Agreement only, the Decommissioning Balance to Complete Cost Estimate and the Decommissioning Cost Estimate shall be notionally allocated among the Stations at any time in accordance with the then current Approved Reference Plan.

(g) Allocation of Disbursements. For purposes of the determination of Payments pursuant to this Agreement, Disbursements in any calendar year from the Decommissioning Segregated Fund shall, notwithstanding how the Disbursement may actually have been expended, be notionally allocated among the Stations *pro rata* to that year's portion of the Decommissioning Cost Estimate notionally allocated to the Station for such calendar year, in accordance with the then current Approved Reference Plan.

4.6.3 Remaining Operating Period.

(a) If a new or amended Reference Plan becomes an Approved Reference Plan more than five (5) years prior to the Operating Period End Date for a Station as contained in the previous Approved Reference Plan and such Station has Permanently Shutdown or the Operating Period End Date in the new Approved Reference Plan is earlier than the Operating Period End Date contained in the previous Approved Reference Plan, then the Remaining Operating Period for that Station shall be the greater of (i) five (5) years from the date of the new Approved Reference Plan and (ii) the Remaining Operating Period for such Station in the new Approved Reference Plan.

(b) If a new or amended Reference Plan becomes an Approved Reference Plan fewer than five (5) years prior to the Operating Period End Date for a Station as contained in the previous Approved Reference Plan, then the Remaining Operating Period for such Station shall, notwithstanding the foregoing, be the Remaining Operating Period for such Station under the immediately preceding Approved Reference Plan.

(c) If a Triggering Event occurs after a Station has Permanently Shutdown, and the Fair Market Value of the assets notionally allocated to that Station is not equal to the portion of the Decommissioning Balance to Complete Cost Estimate then notionally allocated to that Station, the Remaining Operating Period for that Station shall be deemed to be five (5) years from the date of the Triggering Event.

(d) If the amount, if any, as at the date of the Triggering Event, by which the Decommissioning Balance to Complete Cost Estimate exceeds the Fair Market Value of the assets of the Decommissioning Segregated Fund under the then current Approved Reference Plan is greater than such excess amount as at the date of the Triggering Event under the immediately preceding Approved Reference Plan, then the Remaining Operating Period for each Station shall be the greater of the (i) Remaining Operating Period for that Station under the then current Approved Reference Plan and (ii) five (5) years from the date of the Triggering Event.

Board Staff Interrogatory #06

Ref: Exh H2-1-2 pages 2 to 3

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

Interrogatory

The pre-filed evidence states that, "… OPG and Bruce Power reached an agreement that effectively binds Bruce Power to the renewal of the Bruce Lease beyond the initial expiry date." The pre-filed evidence also states that "… the expected lease term for accounting purposes was extended to December 2036."

a) Please provide the date to which the Bruce Lease agreement between OPG and Bruce Power was extended.

b) Please explain the statement that "the expected lease term for accounting purposes was extended to December 2036" with respect to the actual terms and conditions in the Bruce Lease agreement between OPG and Bruce Power.

Response

a) As noted in Ex. H2-1-2, page 1, the Bruce Lease agreement between OPG and Bruce Power has an initial term ending in December 2018 with Bruce Power having an option to extend the lease term for up to an additional 25 years. Bruce Power has not exercised its renewal option at this time.

b) The requested explanation was first provided in EB-2010-0008, Ex. G2-2-1, p. 3. This explanation was referenced in Ex. H2-1-2, p. 2, Note 2 and is provided below.

> *In late 2008, OPG and Bruce Power reached an agreement that effectively binds Bruce Power to the renewal of the Bruce Lease beyond the initial expiry date of December 31, 2018. If Bruce Power fails to renew and extend the Bruce Lease to at least June 2027 or if Bruce Power terminates the lease prior to the expiration of the initial term, it will make a one time payment to OPG in accordance with a time-based schedule set out in the agreement. By entering into this agreement, OPG gained greater certainty of lease revenues beyond the initial term. For its part, OPG agreed not to seek a base rent increase resulting from the increase in the estimated cost of decommissioning the Bruce A and B stations in the 2006 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan. As a result of this significant change in the lease, GAAP required the accounting for the lease to be reassessed. The reassessment determined the most likely outcome to be a continuation of the lease to December 2036. OPG is*

> *continuing to record the lease revenues on a straight-line basis but over the period to December 2036.*

There have been no changes with respect to the events and impacts discussed above. The revenue requirement consequences of these events and impacts are reflected in the EB-2010-0008 approved payment amounts.

Board Staff Interrogatory #07

Ref: Exh H2-1-2 pages 4 to 6

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

Interrogatory

The Bruce Lease revenues consist of base rent and supplemental rent.

a) Please clarify whether the Bruce Supplemental Rent Revenues are accounted as a derivative (i.e. standalone) or as an embedded derivative (i.e., hybrid as part of the Bruce Lease host contract) in relation to the terms and conditions in the Bruce Lease agreement.

b) What is the accounting basis upon which the Bruce Lease can be accounted for as a derivative? Please include in the response references to the specific accounting standard(s) in Section 3855 of the CICA Handbook that qualifies the conditional reduction to Bruce Supplemental Rent Revenues in the future accounting periods, embedded in the terms of the Bruce Lease, for derivative accounting treatment.

c) Is derivative accounting treatment under Canadian GAAP prescriptive for leases in the situation where there are conditions attached to a lease, or are there other accounting treatments available under Canadian or USGAAP for rentals contingent on factors related to future use or price indexes? If so, please identify the other accounting treatments in the applicable standard.

Response

a) The rights and obligations under the Bruce Lease agreement, including revenue from supplemental rent payments, are not in and of themselves derivatives and are not accounted for as such. In accordance with CGAAP, these rights and obligations, including supplemental rent, are accounted for under CICA Handbook Section 3065, *Leases*. Supplemental rent meets the definition of and is accounted for as contingent rent under Section 3065, whereby it is accrued when it becomes payable based on the terms of the lease (i.e., recognized on a “cash basis”) because, as stated in Ex. H2-1-2, p.3, lines 30-31, the rent “is not a fixed amount and is contingent on the number and operational state of the Bruce units.”

Separately, what OPG is required to account for as an embedded derivative is the specific provision in the agreement that results in a conditional obligation for OPG to transfer resources (i.e., cash outflow in the form of a partial rebate of the supplemental rent) depending on the level of electricity prices (i.e., if Average HOEP falls below $30/MWh).

b) The accounting basis is found in Section 3855 and reads as follows:
"*An entity, [...] applies this Section to all types of financial instruments except the following:*

(b) Rights and obligations under leases, to which LEASES, Section 3065, applies. However:

[...]

(iii) this Section applies to derivatives that are embedded in leases."

c) The embedded derivative accounting treatment is prescriptive under both Canadian GAAP and USGAAP. The same accounting treatment discussed above with respect to CGAAP also is required by USGAAP. Specifically, Accounting Standards Codification Topic 815, *Derivatives and Hedging*, states in paragraph 815-10-15-79:

"Leases that are within the scope of [Accounting Standards Codification] Topic 840 [Leases] are not derivative instruments subject to this Subtopic, although a derivative instrument embedded in a lease may be subject to the requirements of paragraph 815-15-25-1 [embedded derivatives – recognition]."

Under USGAAP, the conditional provision in the Bruce Lease to rebate a portion of supplemental rent based on electricity prices meets the recognition criteria for an embedded derivative, and must therefore continue to be accounted for as such in accordance with paragraph 815-15-25-1.

The accounting treatment for rent that is contingent on future use is similarly prescriptive under CGAAP (as discussed in response to part a above) and USGAAP. In accordance with Topic 840, OPG must therefore also continue to account for the Bruce Lease using lease accounting requirements, including recognition of revenue from supplemental rent payments on a "cash basis."

Board Staff Interrogatory #08

Ref: Exh H2-1-2 pages 3 to 4

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

Interrogatory

OPG states that,

> Supplemental rent revenue is generally recognized on a cash basis for [CGAAP] financial accounting purposes because it is not a fixed amount and is contingent on the number and operational state of Bruce units. Supplemental rent is also dependent on the Hourly Ontario Energy Price ("HOEP"). A provision in the Bruce Lease requires a partial rebate by OPG to Bruce Power of the supplemental rent payments for the Bruce B units in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") falls below $30/MWh, and certain other conditions are met.
>
> As discussed in the EB-2010-0008 evidence, this conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, must be accounted for as a derivative.

a) Please explain why the supplemental rent revenue is generally recognized on a cash basis for CGAAP financial accounting purposes when OPG has accounted for it as a derivative?
b) Please identify the "certain other conditions" that must be met for the partial rebate of supplemental rent, in addition to the condition of the annual arithmetic average of the HOEP ("Average HOEP") falling below $30/MWh.

Response

a) See L-1-1 Staff-07.

b) "Certain other conditions" refers to the Bruce units being operational at any time during the calendar year and not being subject to the Bruce Power Refurbishment Implementation Agreement ("BPRIA") between Bruce Power and the Ontario Power Authority. As the BPRIA currently applies to all Bruce A units, the rebate provision currently applies only to the Bruce B units. For clarity, the rebate provision could apply to Bruce A units in the future, if they are no longer subject to the BPRIA.

Board Staff Interrogatory #09

Ref: Exh H2-1-2 page 4

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

Interrogatory

OPG states, "In a year where Average HOEP falls below $30/MWh, the reduction in the supplemental rent payments to OPG determined at the end of that year typically would be offset by a reduction in the derivative liability. The resulting net effect is that the amount of supplemental rent revenue recognized for accounting purposes in that year would be unchanged [scenario 1]. However, any change to the present value of the expected reductions in payments over the derivative's remaining life (i.e., in subsequent years) must be recognized as an adjustment to the fair value of the derivative liability and revenue in the current year [scenario 2]."

a) For the first scenario above, please confirm that this was the case in 2011, where a reduction in the supplemental rent payments at the end of the year typically would be offset by a reduction in the derivative liability but the resulting net effect in that year would be unchanged. In addition, please provide the journal entries for 2011.

b) For the second scenario above, please confirm that this will be the case in 2012 resulting in an adjustment to the fair value of the derivative liability and revenue in the current year. In addition, please provide the journal entries for 2012 that relate to the projected amounts.

c) Please provide and illustrate the financial impacts for the derivative accounting related to supplemental rent under the applicable line items and associated amounts in the 2011 audited financial statements and the same on a pro forma basis in the 2012 financial statements.

Response

The statements cited in the question do not constitute mutually exclusive scenarios. The description was included to clarify that, in a year where the Average HOEP falls below $30/MWh, the actual reduction in the supplemental rent cash payment through a partial rebate does not typically impact the amount of revenue recognized for accounting purposes. Rather, it is accounted for as a reduction in the derivative liability which would have been established in prior periods. This is expected to be the case for 2012, as shown in projected journal entry #4-2012 in part b) below.

a) As stated at Ex. H2-1-2, p. 5, lines 3-5, "Since the Average HOEP was above $30/MWh in 2011, there was no reduction in the supplemental rent payments received by OPG for that year." Under these circumstances, any amounts previously recognized as adjustments to the fair value of the liability and accumulated reductions to revenue in relation to expectations of the reduction in the cash payment for that year are fully reversed, as an increase to revenue, by the end of that year. This was the case for 2011, as shown in journal entry #1-2011 below.

The entries recorded during 2011 are summarized as follows:

Entry #1-2011 *– Reversal of amounts recognized in the derivative liability prior to 2011 in relation to expectations of the reduction in the supplemental rent payment for 2011, as the Average HOEP for 2011 did not fall beyond $30/MWh.*

DR	Derivative Liability	$42M	
CR	Supplemental Rent Revenue		$42M

Additionally, in accordance with generally accepted accounting principles, the changes in fair value of the derivative liability must also reflect changes in the present value of the probability-weighted expectations of rent rebates for the remaining accounting service life (beyond the current year) of the applicable Bruce units (i.e., journal entry #2-2011 and projected journal entry #3-2012 below).

Entry #2-2011 *– Net amounts recognized in the derivative liability during 2011 for changes in the present value of probability-weighted expectations of reductions in supplemental rent payments for the remaining accounting service life (beyond 2011) of the Bruce station, i.e., for 2012 to 2014.*

DR	Supplemental Rent Revenue	$65M	
CR	Derivative Liability		$65M

The net effect of the two entries is a reduction to supplemental rent revenue of $23M recognized in 2011, as noted at Ex. H2-1-2, p. 4, line 27 to p. 5, line 2.

b) In respect of 2012, footnote 6 at p. 5 in Ex. H2-1-2 states: "In contrast, the Average HOEP for the first six months of 2012 was $19.62/MWh." At the end of the first six months of 2012, as shown in response to interrogatory L-1-1 Staff-10 (c), OPG projected that the supplemental rent cash payment for 2012 would be reduced, and therefore projected journal entry #4-2012 as described in the preamble to this response above.

The entries recorded during the first six months of 2012 are summarized as follows:

Entry #1-2012 *– Net amounts recognized in the derivative liability during the first six months of 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 estimated 2012 rent rebate.*

DR	Supplemental Rent Revenue	$10M	
CR	Derivative Liability		$10M

***Entry #2-2012** – Net amounts recognized in the derivative liability during the first six months of 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 station, i.e., for 2013-2014.*

DR	Supplemental Rent Revenue	$33M	
CR	Derivative Liability		$33M

The net effect of these two entries is a reduction to supplemental rent revenue of $43M recognized during the first six months of 2012, as noted at Ex. H2-1-2, p. 6, lines 1-4.

The entries for the remaining six months of 2012 underlying the forecast supplemental rent revenue provided in the pre-filed evidence are summarized as follows:

***Entry #3-2012** – Amount projected to be 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 - 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	$306M	
CR	Derivative Liability		$306M

The projected amount of $306M is as indicated at Ex. H2-1-2, p. 5, lines 21-24.

***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	$75M	
CR	Cash		$75M

The estimated amount of the rent rebate of $75M is as indicated at Ex. H1-1-1, Table 14b, line 15, col. (b).[1]

c) The following tables present the above journal entries in the form of increases and decreases to the line items on OPG's actual 2011 and pro-forma 2012 balance sheet and income statement in accordance with both CGAAP and USGAAP.

[1] The estimate of $75M as the amount of the 2012 rent rebate reflects a rounded approximation for forecasting purposes at the time of the preparation of the pre-filed evidence. The actual amount of the rent rebate will be calculated pursuant to the terms of the Bruce Lease Agreement.

d) Balance Sheet

$	**Actual 2011**	**Pro-Forma 2012**
Cash	–	-75M
Derivative Liability	+23M	+274M[1]
Retained Earnings	-23M	-349M

Income Statement

$	**Actual 2011**	**Pro-Forma 2012**
Revenue	-23M	-349M[2]

Note 1: Sum of $10M (entry #1-2012), $33M (entry #2-2012) and $306M (entry #3-2012), less $75M (entry #4-2012)

Note 2: Sum of $10M (entry #1-2012), $33M (entry #2-2012) and $306M (entry #3-2012)

Board Staff Interrogatory #10

Ref: H2-1-2 page 4 to 6

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

Interrogatory

OPG states at Exh H2-1-2 page 4 that,

> "The derivative is measured at fair value for financial accounting purposes and changes in its fair value are recognized as adjustments to revenue. The fair value is derived based on the present value of the probability-weighted expectations of reductions in supplemental rent payments in the future as a result of **Average HOEP falling below $30/MWh** calculated over the remaining accounting service life of the applicable Bruce units…any change to the present value of the expected reductions in payments over the derivative's remaining life (i.e., in subsequent years) must be **recognized as an adjustment to the fair value of the derivative liability and revenue in the current year**...OPG calculates the fair value of the derivative using a valuation model." [Emphasis added]

a) Has this condition in the Bruce Lease (or as amended thereafter) of an "Average HOEP falling below $30/MWh" (or other threshold conditions) been triggered in the past which gave rise to a recognition of an adjustment to the fair value of the derivative liability and revenue in the current year? If so, please provide the details.

b) Are there other terms and conditions in the Bruce Lease (or as amended thereafter) which may have financial and revenue requirement consequences that have not been made available to the Board in previous proceedings? If so, please provide the details including the estimated impacts to the revenue requirement/payment amounts.

c) Please provide the detailed calculation results of the valuation model including provision of all key significant inputs, assumptions - including financial amendments to the Bruce Lease agreement, and data used including HOEP forecasts - showing and explaining the derivation of supplemental rent revenues.

d) Please provide the HOEP forecast used each year in the derivation of supplemental rent revenues and the methodology used to determine the forecast values.

Response

a) The impacts of the referenced condition for 2011 and 2012 are described in response to interrogatory Ex. L1-1-1 Staff-09. Prior to 2011, the partial rent rebate as a result of Average HOEP falling below $30/MWh was triggered only once, in 2009. The related mechanics, calculation details and the impact of the referenced condition on Bruce Lease supplemental rent revenue recognized for accounting purposes for the period from April 1, 2008 to December 31, 2010 can be found in EB-2010-0008, Ex G2-2-1 page 4, where they were reflected in the December 31, 2010 balance of the Bruce Lease Net Revenues Variance Account approved in the EB-2010-0008 Payment Amounts Order.

b) As noted above, evidence regarding the conditional partial rent rebate and its impact was previously provided to the OEB. This condition has been in effect since prior to regulation of OPG. OPG's evidence filed in previous proceedings has reflected all known information related to the Bruce Lease Agreement that had revenue requirement consequences for the respective applications.

c) The calculation results of the derivative valuation model and related inputs underpinning the projection of 2012 supplemental rent revenue provided in the pre-filed evidence are provided as Attachment 1. The projection of the impact of adjustments to the fair value of the derivative on 2012 supplemental rent revenue reflects:
   (i) the upward change in the actual value of the derivative between year-end 2011 (Attachment 1, page 1 of 3) and the end of the second quarter of 2012 (Attachment 1, page 2 of 3); and
   (ii) the projected upward adjustment in the derivative liability as a result of the expected extension of the accounting service life of the Bruce B units for an additional five years to 2019 (Attachment 1, page 3 of 3).

   A consistent valuation model and approach were used to derive these values.

   The valuation model calculates the value of the derivative liability based on the expected annual Average HOEP for each of the remaining years of the accounting life of the Bruce B units.[1] The expected annual Average HOEP is determined by removing a risk premium from OPG's proprietary forward price curve as of the date of the valuation. The expected annual Average HOEP value for the current year is a weighted combination of the actual Average HOEP value from the beginning of the year to the valuation date (sourced from publicly-available information from the IESO) and the expected Average HOEP for the remainder of the year determined in the manner described above. The expected annual Average HOEP for each year, together with the estimated volatility based on historical forward price curve data, is then used to determine the probability for each year that the actual Average HOEP will be below $30/MWh.

[1] As noted in response to interrogatory Ex. L-1-1 Staff-08(b), Bruce A units are not subject to the partial rent rebate provision as long as they remain subject to the Bruce Power Refurbishment Implementation Agreement between Bruce Power and the Ontario Power Authority.

Pursuant to the Bruce Lease, the amount of the partial rent rebate is the difference between the full CPI-adjusted supplemental rent otherwise payable for the operational Bruce B units minus $12 million per unit. The valuation model calculates the derivative liability by multiplying the present value, as of the valuation date, of the projected rebate amount for each of the remaining years (including the current year) of the accounting life of the Bruce B units, determined using an estimated CPI for each year, by that year's probability factor, determined as described above.

There were no amendments to the Bruce Lease in 2011 or 2012 in relation to the partial supplemental rent rebate provision. This provision has been in existence since before OPG become subject to regulation.

d) See part (c)

Year End 2011 Valuation

Valuation Date	**Sat 31-Dec-2011**			**Bruce Embedded Derivative Valuation**		
Discount Rate	2.60%					
		2011	**2012**	**2013**	**2014**	**Total**
Estimated CPI		2.95%	2.10%	2.00%	2.00%	
Full Supplemental Rent		122,995,447	125,578,351	128,089,918	130,651,716	507,315,432
Reduced Supplemental Rent		48,000,000	48,000,000	48,000,000	48,000,000	192,000,000
Full Rent Rebate		74,995,447	77,578,351	80,089,918	82,651,716	315,315,432
PV of Full Rent Rebate		74,995,447	75,612,428	76,082,212	76,526,138	303,216,224
Exercise Probability		0.00%	88.93%	82.10%	74.26%	
PV of Expected Rebate		**-**	**67,243,883**	**62,465,778**	**56,824,731**	**186,534,392**
Average HOEP to Date		**30.15**				
Daily Volatility			1.38%	1.38%	1.38%	
Expected Annual Average HOEP			**23.53**	**23.69**	**25.74**	

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

Q2 2012 Valuation

Valuation Date	**Fri 29-Jun-2012**	**Bruce Embedded Derivative Valuation**			
Discount Rate	2.46%				
		2012	**2013**	**2014**	**Total**
Estimated CPI		2.18%	2.50%	2.10%	
Full Supplemental Rent		125,609,563	128,749,802	131,453,548	385,812,913
Reduced Supplemental Rent		48,000,000	48,000,000	48,000,000	144,000,000
Full Rent Rebate		77,609,563	80,749,802	83,453,548	241,812,913
PV of Full Rent Rebate		76,662,043	77,848,861	78,523,790	233,034,694
Exercise Probability		100.00%	98.92%	95.69%	
PV of Expected Rebate		**76,662,040**	**77,006,033**	**75,142,961**	**228,811,034**
Average HOEP to Date		**19.62**			
Daily Volatility		1.17%	1.09%	1.09%	
Expected Annual Average HOEP		**20.05**	**18.84**	**20.31**	

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

Valuation of Life Extension

Valuation Date	**Fri 29-Jun-2012**			**Bruce Embedded Derivative Valuation**		
Discount Rate	2.46%			**— Life Extension —**		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Estimated CPI	2.10%	2.10%	2.10%	2.10%	2.10%	
Full Supplemental Rent	134,214,072	137,032,568	139,910,252	142,848,367	145,848,183	699,853,442
Reduced Supplemental Rent	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	240,000,000
Full Rent Rebate	86,214,072	89,032,568	91,910,252	94,848,367	97,848,183	459,853,442
PV of Full Rent Rebate	79,173,575	79,798,852	80,400,241	80,978,346	81,533,757	401,884,770
Exercise Probability	89.24%	81.71%	77.42%	71.32%	61.64%	
PV of Expected Rebate	**70,657,804**	**65,205,030**	**62,244,969**	**57,751,797**	**50,253,712**	**306,113,311**
Average HOEP to Date						
Daily Volatility	1.09%	1.09%	1.09%	1.09%	1.09%	
Expected Annual Average HOEP	**22.82**	**24.77**	**25.71**	**26.94**	**28.75**	

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

Board Staff Interrogatory #11

Ref: Exh H2-1-2 page 4 to 6

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

Interrogatory

a) Please provide the annual supplemental rent revenues, including breakdown by reductions due to unit refurbishments and HOEP rebates, recognized and reported for financial accounting purposes since the inception of the Bruce Lease and a summary of the key significant inputs and assumptions used to derive each amount.

b) Please provide the annual supplemental rent payments received from Bruce Power L.P., including the gross amounts and any supplemental rent reduction due to refurbished Bruce units and rebates due to HOEP, since the inception of the Bruce Lease.

c) Please revise Table 14 and 14a of Exh H1-1-1 to reflect the projected 2012 supplemental rent payments to be received on an actual basis from Bruce Power comprising the gross supplemental rent amounts less any reductions due to refurbished Bruce units and rebates due to HOEP less than $30/MWh in the year (i.e., no derivative accounting to be reflected in supplemental rent payments).

Response

The reference to “rent reductions due to refurbished units” in the question is not accurate. OPG did not collect any supplemental rent for the Bruce A, Units 1 and 2 since Bruce Power assumed the operations of the Bruce Nuclear Generating Stations in 2001. Supplemental rent is collected once the units enter commercial operation (Q4, 2012) subsequent to having been refurbished by Bruce Power.

OPG has provided information in both EB-2010-0008 and EB-2007-0905 regarding supplemental rent; however that information is not relevant to OPG’s application to clear balances accumulated in the deferral and variance accounts in 2011 and 2012.

a) The supplemental rent revenues under the Bruce Lease reported for financial accounting purposes are provided below for 2011 (actual) and for 2012 (projection as presented in the pre-filed evidence):

Chart 1

	2011 Actual - $M	**2012 Projected $M**
Supplemental Rent Revenue – Un-refurbished Units	184.5	188.4
Supplemental Rent Revenue – Refurbished Units	–	8.0
Adjustment for changes in the fair value of the derivative embedded in the Bruce Lease	(23.5)	(348.3)
Net Supplemental Rent Revenue	**161.0**	**(151.9)**

The key significant inputs and assumptions are:

- Revenue is recognized for financial accounting purposes as described in Ex. L-1-1 Staff-07.
- The annual supplemental rent rates for Bruce units are escalated annually by the Consumer Price Index (Ontario) ("CPI") for each unit that is operational at any time during the year. This is subject to refurbished units being declared in commercial operation, in which case the annual rent is prorated.
- The actual CPI values used in determining the 2011 and 2012 supplemental rent rates are 117.8 and 120.6, respectively, resulting in escalation rates of approximately 2.88 per cent and 2.38 per cent, respectively.
- Bruce A Units 1 and 2 are declared in commercial operation in 2012. Supplemental rent determined using the actual commercial in-service of Q4, 2012 is approximately $2.5M. The $8.0M above assumed an earlier in service date.
- The key significant inputs and assumptions used in the determination of the fair value of the derivative are provided and explained in Ex. L-1-1 Staff-10 (c).

b) The supplemental rent payments from Bruce Power, less the rebate, if any, due to Average HOEP falling below $30/MWh are provided below for 2011 (actual) and for 2012 (projection as presented in the pre-filed evidence):

Chart 2

	2011 Actual $M	**2012 Projected $M**
Supplemental Rent Payment – Un-refurbished Units	184.5	188.4
Supplemental Rent Payment – Refurbished Units[1]	–	8.0
Partial Rent Rebate Based on Average HOEP[2]	–	(75.0)
Net Supplemental Rent	**184.5**	**121.4**

Ex. L1-1-Staff 12 (b) supports the disposition of the Bruce Lease Net Revenue Variance Account on an accounting basis, rather than a cash basis. The requested tables derive the actual and forecast cash payments and therefore are not consistent with the accounting basis that the OEB has directed OPG to use for Bruce Lease revenues and costs (EB-2007-0905, Decision with Reasons, pp. 109-112).

Nevertheless, Attachment 1, Tables 1-3 reflect revised Tables 14, 14a and 14b on the requested basis. Table 3 is included because the changes in the fair value of the embedded derivative impact future taxes. Future income taxes are lower when upward adjustments to the fair value of the derivative are recognized. Therefore, in the absence of derivative accounting for 2012, a future income tax expense of $5.7M (Table 3, line 32, col. (b)), as compared to a credit of $62.6M (Ex. H1-1-1 Table 14b, line 32, col. (b)), must be reflected.

[1]As noted in response to Part a) above, the actual supplemental rent payment for refurbished units will be approximately $2.5M, not the forecast $8.0M at the time OPG filed evidence for this application.
[2] The estimate of $75M as the amount of the 2012 rent rebate reflects a rounded approximation for forecasting purposes at the time of the preparation of the pre-filed evidence. The actual amount of the rent rebate will be calculated pursuant to the terms of the Bruce Lease.

Table 1

Bruce Lease Net Revenues Variance Account Without Derivative Accounting for 2012[1]

Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
1	**Actual Bruce Lease Net Revenues[2] ($M)**	32.7	35.5	31.3
2	**Forecast Bruce Lease Net Revenues - EB-2009-0174 / EB-2010-0008[3] ($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 ($/MWh)** (line 2 / line 3)	2.18	2.66	2.66
5	**Actual Nuclear Production[4] (TWh)**	8.8	39.8	49.5
6	**Amount Credited to Customers ($M)** (line 4 x line 5)	19.1	105.9	131.5
7	**Addition to Variance Account ($M)** (line 6 - line 1)	(13.6)	70.4	100.2

Notes:

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

2 From Ex. L-1-1 Staff-11 Table 2, 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.

Table 2
Bruce Lease Net Revenues Variance Account Without Derivative Accounting for 2012
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 Projected	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	14.8	12.4	2.4
3	**Cobalt-60**	0.0	0.5	0.5	0.5	(0.0)	0.5	0.5	0.0
4	**Total Services**	3.0	13.2	16.2	14.7	1.5	16.0	13.4	2.5
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)	121.4	202.3	(80.9)
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)	174.4	255.3	(81.0)
9	**Total Revenues**	38.3	191.9	230.2	254.4	(24.2)	190.3	268.7	(78.4)
	Costs:								
10	**Depreciation**	6.0	27.2	33.2	34.5	(1.3)	77.7	34.5	43.2
11	**Property Tax**	2.1	10.1	12.2	13.6	(1.4)	12.4	14.1	(1.7)
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	328.5	307.2	21.3
14	**(Earnings) Losses on Segregated Funds**[1]	(68.0)	(172.1)	(240.1)	(286.2)	46.1	(322.3)	(304.6)	(17.7)
15	**Used Fuel Storage and Disposal**[1]	3.0	24.0	27.0	17.0	10.1	43.5	24.0	19.5
16	**Waste Management Variable Expenses**[1]	0.2	0.8	1.0	0.8	0.1	1.8	0.7	1.1
17	**Interest**	2.2	9.4	11.6	11.9	(0.3)	11.7	6.9	4.9
18	**Total Costs Before Income Tax**	(4.9)	146.5	141.6	86.1	55.5	153.3	82.8	70.5
19	**Income Tax - Current**[2]	0.0	0.0	0.0	0.0	0.0	0.0	8.6	(8.6)
20	**Income Tax - Future**[3]	10.5	9.8	20.3	40.2	(19.9)	5.7	34.3	(28.6)
21	**Total Costs**	5.6	156.4	161.9	126.3	35.6	159.0	125.7	33.3
22	**Bruce Lease Net Revenues** (line 9 - line 21)	32.7	35.5	68.2	128.1	(59.8)	31.3	143.0	(111.7)

Notes:
1 Amounts in cols. (c) and (f) are from Ex. H2-1-1 Table 2, cols. (b) and (c) respectively.
2 Amounts in cols. (c) and (f) are from Ex. L1-1-1 Staff-11 Table 3, line 22, cols. (a) and (b) respectively.
3 Amounts in cols. (c) and (f) are from Ex. L1-1-1 Staff-11 Table 3, line 32, cols. (a) and (b) respectively.

Table 3
Calculation of Bruce Income Taxes - Without Derivative Accounting for 2012 ($M)
Years Ending December 31, 2011 and 2012

Line No.	Particulars	2011 Actual	2012 Projected
		(a)	(b)
	Determination of Taxable Income		
1	**Earnings (Loss) Before Tax**[1]	88.6	37.0
	Additions for Tax Purposes - Temporary Differences:		
2	**Base Rent Accrual**	37.1	39.1
3	**Depreciation**	33.2	77.7
4	**Accretion**	296.6	328.5
5	**Used Fuel and Waste Management Expenses**	28.0	45.3
6	**Receipts from Nuclear Segregated Funds**	24.0	42.5
7	**Adjustment Related to Embedded Derivative**	23.5	0.0
8	**Other**	2.1	4.1
9	**Total Additions - Temporary Differences**	444.6	537.2
	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	120.4
13	**Contributions to Nuclear Segregated Funds**	105.5	113.5
14	**Earnings (Losses) on Nuclear Segregated Funds**	240.1	322.3
15	**Supplemental Rent Payment Reduction**	0.0	0.0
16	**Total Deductions - Temporary Differences**	420.7	562.2
17	**Taxable Income/(Loss) Before Loss Carry-Over**	98.3	(2.3)
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	(98.3)	2.3
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)	(6.3)
24	**Income Tax Rate - Current**	26.50%	25.00%
25	**Future Income Taxes - Short-Term**	4.7	1.6
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)	41.7	(18.8)
27	**Income Tax Rate - Long-Term**	25.00%	25.00%
28	**Future Income Taxes - Long-Term**	(10.4)	4.7
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)	(98.3)	2.3
30	**Income Tax Rate - Current**	26.50%	25.00%
31	**Future Income Taxes - Tax Loss / Tax Loss Carry-Over**	26.0	(0.6)
32	**Future Income Tax - Total** (line 25 + line 28 + line 31)	20.3	5.7
	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. L1-1-1 Staff-11 Table 2, Line 9 and Total Costs Before Income Tax in Ex. L1-1-1 Staff-11, Table 2, Line 18 for the corresponding years.

Board Staff Interrogatory #12

Ref: Exh H2-1-2 page 5
Exh H1-1-1 Table 14 and 14a

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

Interrogatory

Effective December 31, 2012, OPG expects to extend the estimated average service life of the Bruce B station from 2014 to 2019. OPG states that (Exh H2-1-2 page 5), "…the 2012 supplemental rent revenue forecast is $354.2M less than the EB-2010-0008 approved forecast, as shown in Exh H1-1-1 Table 14a. The extended average service life is projected to increase the fair value of the derivative liability at December 31, 2012 by approximately $306M based on current probability-weighted expectations of future Average HOEP over the additional life of the applicable Bruce units."

According to Table 14a, the 2012 approved forecast for supplemental rent revenue was $202.3M as compared to the 2012 projected amount of -$151.9M, which results in an extraordinary shortfall of $354.2M. In addition, as shown in Tables 14 and 14a, this change to supplemental rent revenues is the key reason (aside from an increase in total costs before income tax of $70.5M) for the $305M addition to the variance account in 2012.

a) Please confirm whether the 2012 projected supplemental rent revenue amount of -$151.9M includes and factors in all supplemental rent revenues in relation to all future years of the Bruce Lease, which for accounting purposes were recognized and accounted for on December 31, 2012.

b) Board staff notes that this extraordinary financial accounting change in the supplemental rent revenue of –$354.2M appears to have not occurred before and was caused by the probability of receiving lower supplemental rent revenues tied to the forecast of lower HOEP in the future. Please explain why ratepayers should be held responsible for these amounts in their current electricity payments?

c) Please explain whether or not OPG considered other ratemaking mechanisms by which this extraordinary supplemental rent revenue shortfall amount of $354.2M could be mitigated or smoothed (other than the proposed recovery period of 4 years).

d) Are there any regulatory accounting mechanisms by which the financial accounting impacts of the rebates attributable to supplemental rent revenue (due to HOEP less than $30/MWh) could be mitigated or smoothed? For example, if changes to the fair value of the derivative liability are triggered in a particular period, this change could be deferred and recorded in a "tracking account" and the accumulated balance could then be amortized annually over the average remaining accounting service life of the Bruce units. As such, the current period amortized amount would be "added" annually to the supplemental rent revenue. In this fashion, the accounting impacts of the rebates are smoothed for inclusion in the determination of the Bruce Lease net revenues.

Response

The projected 2012 supplemental revenue amount of -$151.9M and resulting difference as compared to the 2012 forecast reflected in the EB-2010-0008 payment amounts result from the required application of generally accepted accounting principles, which OPG has consistently applied in respect of all aspects of the Bruce Lease since April 1, 2008, as directed by the OEB, and which are followed for the purposes of OPG's consolidated financial statements. Thus, they are not "extraordinary."

Part a)
OPG confirms that -$151.9M is OPG's forecast of 2012 supplemental rent revenue amount as of June 30, 2012 determined in accordance with CGAAP and USGAAP. This forecast amount includes a projected present value of all probability-weighted expectations, as of December 31, 2012, of reductions in Bruce B supplemental rent payments to December 31, 2019. These reductions occur as a result of Average HOEP falling below $30/MWh.

Part b)
Sections 6(2) 9 and 6(2) 10 of O. Reg 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts.

The basis on which Bruce lease costs and revenues are to be determined was an issue in EB-2007-0905. In that proceeding, Board staff proposed, and the OEB required, that Bruce lease costs and revenues be calculated in accordance with GAAP for non-regulated businesses. This accounting treatment was reaffirmed in EB-2010-0008.

As noted in L-1-1 Staff-07, CGAAP and USGAAP both require embedded derivative accounting treatment for the conditional partial rebate of the supplemental rent revenues under the Bruce lease. This treatment requires that any change in the present value of the expected value of the reductions in payments over the derivative's remaining life must be recognized as an adjustment to the fair market value of the derivative liability and revenue in the current year.

OPG's proposed treatment of the $354.2M forecast shortfall in supplemental rent relative to the EB-2010-008 forecast is the only allowable treatment for accounting purposes under CGAAP and USGAAP.

Finally, OEB Staff's question states that the lower HOEP "appears to have not occurred before," which is not correct. In EB-2010-0008 (Ex.G2-2-1, p. 4) OPG explained both the existence and mechanics of the Bruce Lease supplemental rent and the impact of this accounting treatment in 2009. This subject was further probed in the EB-2010-0008 Technical Conference through Board staff question 34, addressed starting at page 118 of the transcript. Proposed 2009 amounts recorded in the Bruce Lease Net Revenue Variance Account were included in the December 31, 2010 account balance approved for recovery by the OEB in the EB-2010-0008 Decision with Reasons.

Part c) No. As discussed in Ex H1-2-1, pages 3 and 4, OPG has proposed to amortize the balances in the Pension/OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account over a 48 month period in order to lessen ratepayer impact.

Part d) OPG is of the view that the simplest and most effective method of customer impact mitigation considers the total effect of all matters in an application. OPG's application reflects this mitigation approach as discussed in part c) above. OPG is of the view that its proposed mitigation is reasonable.

While various instruments could be used to smooth the impact of GAAP, OPG believes that simplicity should be encouraged, a position that was supported by Board staff in EB-2010-0008.

Board Staff Interrogatory #13

Ref: Exh H1-1-1
Exh H2-1-2

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

Interrogatory

Should the clearance of the 2012 balance in the Bruce Lease Net Revenues Variance Account included in this non-cost of service application be set aside for review in a future cost of service payment application proceeding? If not, please provide reasons.

Response

No, it should not be set aside. OPG filed an application to clear various deferral accounts, including the Bruce Lease Net Revenues Variance Account. The OEB has accepted this application and scheduled a proceeding to decide, among other things: "Are the balances for recovery in each of the deferral and variance accounts appropriate"? Given these actions, there is no basis for deferring the clearance of this account to a future proceeding.

Moreover, there would be no advantage to deferral. OPG has proposed to recover the audited balances at December 31, 2012 in the deferral and variance accounts submitted for clearance. No additional information will be available on these account balances in any future forecast test period cost of service application.

Further, as many of the costs recorded in the account reflect the Bruce lease portion of the updated ONFA reference plan discussed in evidence in the current application in Ex H2-1-1, it is efficient to consider the clearance of the Bruce Lease Net Revenues Variance Account in the current application.

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.

AMPCO Interrogatory #01

Ref: Exhibit H2-2-1 Page 3 Lines 6-14

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

Interrogatory

AMPCO Interrogatory #1

a) Please provide additional detail about the site readiness activities described in the referenced section, including the "relocation of certain Darlington facilities", including specific explanation as to why these are "non-capital costs."

Response

Site investigation/readiness activities which total \$5.1M out of the total \$49.4M expenditures in 2011 - 2012 are to ensure the New Nuclear at Darlington ("NND") initiative is well positioned to support site turnover to the vendor of choice. The site investigation/readiness activities are described at H2-2-1 page 3, and the following list provides some additional detail regarding work performed:

- Archeological investigation at the site as part of the commitments made by OPG as part of the application for the Licence to Prepare the Site.
- Relocation of Thermo Luminescent Devices ("TLDs") monitoring equipment (TLDs are dosimeters that measure exposure to radiation). Relocation of this equipment is designed to minimize future OPG intrusion to the vendor-controlled site.
- Construction of vehicle access roadway (to gain access to relocated TLDs on the east side of new build site).
- Fencing to enclose the new build site area (realignment of the fence separating DNGS and NND portion of the site to restrict access by vendor personnel to the DNGS site and vice versa).
- Relocation of Radiological and Environmental Monitoring Program ("REMP") equipment stations. Relocation of this equipment is designed to minimize future OPG intrusion to the vendor-controlled site.
- Relocation of 44kV line.
- Relocation of seismic monitoring station. OPG requires access to this equipment for maintenance and relocation will minimize future OPG intrusion to the vendor-controlled site.
- Termination of site services (including telephone, power and water to buildings located in the NND site that are to be abandoned or turned over to vendor. Costs relate to planning and co-ordination of system outages.)
- Site cleanup.

Classification of these costs as capital costs would be inconsistent with how OPG capitalizes expenditures. Consistent with USGAAP, OPG charges all costs incurred prior to the approval date of the decision to proceed with a project to OM&A.

AMPCO Interrogatory #02

Ref: Exhibit H1-1-1 Page 4 Lines 1-7
EB-2010-0008 Exhibit H1-1-1 Page 3 Lines 23-31

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

Interrogatory

Preamble: Ancillary services include operating reserve, reactive support/voltage control service, automatic generation control and black start capability. OPG filed these sub-account balances in EB-2010-0008.

a) Please provide these sub-account balances for 2009 to 2012 for hydro-electric and nuclear.

Response

As authorized by the OEB in the EB-2007-0905 and EB-2010-0008 Payment Amounts Orders, OPG maintains two separate sub-accounts for the Ancillary Services Net Revenue Variance Account – the Nuclear sub-account and the Hydroelectric sub-account. Separate sub-accounts are not maintained for each type of ancillary services revenue. Therefore, account transactions for additions, amortization and interests are not calculated or recorded by types of revenue.

In EB-2010-0008, specifically in response to Board Staff interrogatory L-1-138, OPG calculated and provided by types of revenue:

- forecast amounts underpinning OPG's regulated hydroelectric payment amounts approved in EB-2007-0905 for 2009 and the amounts used as the basis of entries into the Hydroelectric sub-account for periods after December 31, 2009 computed in accordance with EB-2009-0174.
- actual regulated hydroelectric ancillary services revenues for 2009 and such budgeted revenues for 2010.

The information requested in this question 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, using an approach similar to that used in the above-noted interrogatory response, OPG provides in Charts 1 and 2 below differences between ancillary services revenues amounts for 2009 to 2012 as described below. The sum of these differences for each period is equal to the addition to each of the Nuclear and Hydroelectric sub-accounts for that period.

2009: Differences between the forecast and actual amounts as determined for 2009 in response to EB-2010-0008 L-1-138.

2010: Differences between the amounts used as the basis of entries into the sub-accounts in accordance with EB-2009-0174 (as in EB-2010-0008 L-1-138) and the actual ancillary services revenues.

January 2011 to February 2011: Differences between amounts used as the basis for entries into the sub-accounts in accordance with EB-2009-0174 (same as 2010, pro-rated by 2/12) and the actual ancillary services revenues.

March 2011 to December 2012: Differences between reference amounts underpinning the two-year 2011 - 2012 revenue requirement approved in EB-2010-0008 and as described at Ex. H1-1-1, p. 3, lines 18-22, and actual (2011) or projected (2012) ancillary services revenues as provided in the pre-filed evidence for this Application.

Chart 1
Ancillary Services Net Revenue Variance - Hydroelectric Sub Account[1]

Ancillary Service ($M)	2009 Actual	2010 Actual	Jan to Feb 2011 Actual	Mar to Dec 2011 Actual	Total 2011 Actual	2012 Projected
Operating Reserve	(6.3)	(1.6)	(0.3)	2.0	1.7	2.4
Reactive Power/ Voltage Control Service	1.8	1.8	0.3	0.1	0.4	0.1
Automatic Generation Control	(4.9)	6.5	1.6	12.0	13.6	14.1
Black Start Capability	0.0	0.0	0.0	0.0	0.0	0.0
Total Addition to Sub Acct	(9.4)	6.7	1.6	14.1	15.7	16.6

[1] Amounts may not add due to rounding. Amounts presented as rounded to $0.0M are not necessarily equal to nil.

Chart 2
Ancillary Services Net Revenue Variance - Nuclear Sub Account[1]

Ancillary Service ($M)	2009 Actual	2010 Actual	Jan to Feb 2011 Actual	Mar to Dec 2011 Actual	Total 2011 Actual	2012 Projected
Operating Reserve	(0.3)	-	0.0	0.2	0.2	0.2
Reactive Power/ Voltage Control Service	1.0	0.6	0.1	0.3	0.4	0.7
Automatic Generation Control	0.0	0.0	0.0	0.0	0.0	0.0
Black Start Capability	0.0	0.0	0.0	0.0	0.0	0.0
Total Addition to Sub Acct	0.7	0.5	0.1	0.5	0.5	0.9

CCC Interrogatory #01

Ref:

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

Interrogatory

What is the proposed timing of the evidence update?

Response

OPG plans to file an update to its evidence in February 2013.

CCC Interrogatory #02

Ref: Ex. A2/T1/S1

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

Interrogatory

Please explain in the context of this application, if OPG is changing the way it records amounts in any of the accounts relative to the approaches approved by the Board in previous applications. If, so please explain the nature of the change(s) and the rationale(s).

Response

OPG continues to calculate and record amounts in its deferral and variance accounts in accordance with the applicable OEB Decisions and Orders and, as applicable, *O. Reg. 53/05*.

CCC Interrogatory #03

Ref: Ex.A2/T1/S1

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

Interrogatory

Please set out OPG's current proposals to seek approval of new payment amounts. As discussed at the Stakeholder session on August 28, 2012, does OPG still intend to file separate and staged applications for nuclear and hydroelectric? If so, what is the proposed timing for those applications?

Response

Please see L-4-1 Staff-29.

CCC Interrogatory #04

Ref: Ex. H1/T1/S1/p. 6

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

Interrogatory

Does the Income and Other Taxes Variance Account record impacts associated will all changes to the tax rates or rules, assessments or re-assessments, new tax policies and court decisions? If not, why not? If not, what has been excluded?

Response

The Income and Other Taxes Variance Account has an effective date of April 1, 2008 and, therefore, records all impacts of the items cited in the question on post-March 31, 2008 regulatory income and capital taxes for the prescribed assets as per the OEB-approved definition of the account at pages 3-4 of Appendix F of the EB-2010-0008 Payment Amounts Order.

With respect to property taxes, this account definition requires OPG to record any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*, as well as any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*.

Impacts on taxes for the Bruce assets are captured in the Bruce Lease Net Revenues Variance Account.

PWU Interrogatory #01

Ref: (1) Exhibit H2/Tab 1/Schedule 1/Pages 2-3 of 8 (Nuclear Liability Deferral Account)
(2): Exhibit L/Tab 2/Schedule 1 Staff-19 b)/Page 3 of 4
(3): Exhibit H2/Tab 1/Schedule 1/Table 3

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

Interrogatory

The current approved ONFA Reference Plan is projected to result in higher accounting nuclear liabilities costs 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.
- Increase in the fixed costs arising from a higher number of used fuel bundles and amount of L&ILW to be managed. This increase results from the projected accounting implementation at the end of 2012 of the changes in estimated service lives of Pickering A and B and Bruce A and B units as contained in the current approved ONFA Reference Plan. The changes in the average service lives, for accounting purposes, of the Bruce A and B stations are discussed in Ex. H2-1-2. Similar changes for Pickering A and B are expected based on OPG's high confidence with respect to the extended service lives of their pressure tubes, as discussed in Ex. H2-2-1.
- The above increases are partially offset by a reduction in decommissioning costs due to several factors including longer station operating lives that reduce the present value of the decommissioning liability, the assumed co-location of decommissioning L&ILW waste with operational waste in the Kincardine DGR, and a more defined characterization of waste in the nuclear facilities that reduces the amount of expensive, higher dose dismantlement work.

a. Did the ONFA Reference Plan approved by the Government of Ontario, effective January 1, 2012, meet the timing requirements as specified by the Ontario Nuclear Funds Agreement (ONFA)?

b. Please describe the process pertaining to the preparation, review and the approval of the update of the ONFA Reference Plan. What are the resources that OPG and the Government are required to make available for the preparation, the review and approval of ONFA reference plans and the underlying data, technical material, financial information and analyses relied upon?

c. Please confirm that the 2012 ONFA Reference Plan cost estimates related to the cost items listed in Ref (1) were based on the assumption that OPG would achieve, by the end of 2012, high confidence in the extended service lives of the Pickering Units 5-8 pressure tubes.

d. Please confirm that end-of-service lives recommended by the Depreciation Review Committee (DRC) are only used for depreciation accounting purposes; and, specifically are not the basis for the ONFA Reference Plan to be approved by the Government.

e. Has OPG made changes to the schedule on its ability, i.e. by late 2012, to demonstrate high confidence in the extended services lives of the Pickering Units 5-8 pressure tubes since the approval of the 2010-2014 Business Plan by the OPG Board of Directors on November 19, 2009?

Response

a) The Reference Plan approved by the Province met the requirements as specified in ONFA.

b) The main steps in the process related to the update of the ONFA Reference Plan are discussed in Ex. H2-1-1, section 2.0. Information related to the resources that OPG and the Government are required to make available for the preparation, the review and approval of ONFA reference plans and the underlying data, technical material, financial information and analyses relied upon, is not relevant to the clearance of OPG's deferral and variance account balances.

c) The introduction to this interrogatory specifically cites the four bullet points that are included in Reference (1). OPG confirms that the 2012 ONFA Reference Plan cost estimates related to all four of these bullets are affected by a change in operating lives of nuclear stations. OPG has assumed that it would achieve high confidence with respect to extended service lives of the Pickering Unit 5-8 pressure tubes by the end of 2012 and reflected that assumption in the four bullet points identified in Reference (1).

d) OPG confirms that the Depreciation Review Committee ("DRC") recommends dates that are used for depreciation purposes and, by extension, to account for applicable items that are impacted by the estimated service lives (e.g., the derivative embedded in the terms of the Bruce Lease agreement). While OPG also confirms that the DRC does not set or recommend dates to be used for the purposes of the ONFA Reference Plan, both estimated station lives as reflected in the approved 2012 ONFA Reference Plan, effective January 1, 2012, and those recommended by the DRC for accounting purposes, effective December 31, 2012, are based on OPG achieving high confidence with respect to the extended service lives of the applicable Pickering and Bruce units by the end of 2012. This is discussed in L-2-1 Staff 19 b) and c) as well as L-2-2 AMPCO-06 and L-2-2 AMPCO-10.

e) As discussed at L-2-2 AMPCO-10, OPG was able to establish high confidence in the extended service lives of the Pickering Units 5-8 fuel channels as of December 2012, and therefore no changes to the schedule were required.

SEC Interrogatory #01

Ref: Ex. A3/1/1,p.2

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

Interrogatory

Please provide an estimate, at as detailed a level as possible, of the impact on the amounts recorded in the Bruce Lease Net Revenues Variance Account as a result of compliance with the Board's requirement not to apply "regulatory constructs".

Response

The OEB's EB-2007-0905 Decision with Reasons established the basis to be used in determining Bruce Lease revenues and costs. The result is that regulatory constructs are not used to determine specific Bruce Lease revenues or costs. Specifically, at page 110 of that Decision, the OEB required:

> "that Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses. The Board's rationale is the same as its rationale for requiring that the cost of the Bruce nuclear liabilities be computed in accordance with GAAP – it is not reasonable to interpret the regulation to find that OPG can calculate revenues from an unregulated activity using an accounting policy that an unregulated company would not be permitted to use."

The question seeks a response to determine the impact of applying "regulatory constructs" to an unregulated activity, an alternative approach that the OEB has already determined as unreasonable. Further, "regulatory constructs" is a broad term that could apply to a number of different revenue and cost items. OPG has no basis to determine which regulatory constructs could or would hypothetically apply to provide the requested response.

Regardless, the scope of this Application is the recovery of amounts recorded in OEB-approved deferral and variance accounts. This includes, where applicable, a consideration of whether amounts have been recorded consistent with the methodology accepted by the OEB in establishing EB-2010-0008 payment amounts and not whether they are consistent with approaches that the OEB has already rejected.

SEC Interrogatory #02

Ref: H2/1/1,Table 2

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 and calculation of the 2012 costs included in lines 4 (UFSD Variable Expenses) and 26 (Depreciation Expense), and an explanation of the increases in those amounts from 2011 to 2012. With respect to the increases in line 4, please show how these increases were incremental relative to approved revenue requirement for 2012.

Response

Used Fuel Variable Expenses
The following Chart 1 provides the requested breakdown and calculation of projected 2012 used fuel storage ("UFS") and used fuel disposal ("UFD") variable expenses presented at line 4 in Ex. H2-1-1, Table 2 for the Bruce facilities.

Chart 1
Projected 2012 Used Fuel Variable Expenses for Bruce Facilities[1]

Facility	Used Fuel Volume (bundles) (a)	UFD Variable Cost Rate ($/bundle) (b)	UFS Variable Cost Rate ($/bundle) (c)	UFD Variable Expenses ($k) (d)=(a)x(b)	UFS Variable Expenses ($k) (e)=(a)x(c)	Total Used Fuel Variable Expense ($k) (f)=(d)+(e)
Bruce A	7,557	1,020	46	7,708	348	8,056
Bruce B	22,522	1,020	556	22,972	12,522	35,495
Total	30,079	N/A	N/A	30,681	12,870	43,550

[1] Numbers may not calculate due to rounding

As noted at Ex. H2-1-1, p. 4, lines 4-10, the projected used fuel variable expenses for the Bruce facilities are higher in 2012 than the actual expenses for 2011 mainly due to higher variable cost rates for 2012, calculated in present value terms, resulting from increases in UFS and UFD cost estimates as well as a lower discount rate in 2012. The higher cost estimates reflect the higher lifecycle liability baseline cost estimates for the UFS and UFD nuclear waste management programs based on the 2012 ONFA Reference Plan. As also stated in the above-noted evidence, the cost rates for 2012 reflect the discount rate of 3.43%, based on the most recent tranche of the nuclear asset retirement obligation ("ARO") as recorded on December 31, 2011 as a result of the 2012 ONFA Reference Plan update process, compared to 4.8% used to derive the 2011 cost rates based on the then-most recent ARO tranche.

The above increase in the used fuel variable expenses in 2012 over 2011 was partially offset by a lower number of used fuel bundles in 2012 as compared to 2011 due to the installation in 2011 of the initial load of bundles into the reactors of Bruce A, Units 1 and 2 as part of the return to service of these units, as noted at Ex. H2-1-2, p. 10, lines 24-29.

As shown at Ex. H1-1-1, Table 14a, line 15, cols (f) to (h), the projected 2012 used fuel variable expenses for the Bruce facilities of $43.5M are $19.5M higher than the 2012 forecast amount of $24.0M reflected in the EB-2010-0008 revenue requirement. As these expense amounts are calculated as the product of the number of used fuel bundles and the applicable UFS and UFD cost rates, differences in expense amounts arise only from changes in these two discrete variables. Therefore, the projected increase in 2012 expenses over the EB-2010-0008 forecast amount is inherently incremental.

For clarity, Chart 2 below is provided with the calculation underlying the $24.0M EB-2010-0008 2012 forecast amount, for comparison with Chart 1 above. A comparison of the two charts demonstrates that higher-than-forecast variable costs rates for 2012, arising from the 2012 ONFA Reference Plan update discussed above, are the primary driver of the higher-than-forecast expenses, as partly offset by a lower-than-forecast number of used fuel bundles for Bruce A.

Chart 2
EB-2010-0008 Forecast 2012 Used Fuel Variable Expenses for Bruce Facilities[1]

Facility	Used Fuel Volume (bundles) (a)	UFD Variable Cost Rate ($/bundle) (b)	UFS Variable Cost Rate ($/bundle) (c)	UFD Variable Expenses ($k) (d)=(a)x(b)	UFS Variable Expenses ($k) (e)=(a)x(c)	Total Used Fuel Variable Expense ($k) (f)=(d)+(e)
Bruce A	18,168	541	218	9,828	3,962	13,790
Bruce B[2]	18,889	541	-	10,218	-	10,218
Total	37,057	N/A	N/A	20,046	3,962	24,008

[1] Numbers may not calculate due to rounding
[2] UFS cost for Bruce B was nil as the then-current assumption was to leave used fuel in wet bays until DGR transfer.

<u>Depreciation Expense</u>
OPG understands that the reference to “line 26 (Depreciation Expense)” in the question should read as a reference to “line 23 (Depreciation Expense)”. The following Chart 3 provides a breakdown and calculation of the projected 2012 depreciation expense for the asset retirement costs (“ARC”) presented at line 23 in Ex. H2-1-1, Table 2 for the Bruce facilities.

Chart 3
Projected 2012 ARC Depreciation Expense for Bruce Facilities[1]

	Bruce A	Bruce B	Total
Net book value of ARC at Jan 1, 2012 ($M) *(A)*	1,196.6	92.2	1,288.8[2]
Remaining service life at Jan 1, 2012 (yrs)[3] (*B)*	31	3	N/A
2012 Depreciation Expense ($M) *(C)=(A)/(B)*	38.6	30.7	69.1

[1] Numbers may not calculate due to rounding
[2] Total opening ARC net book value as per Ex. H2-1-1, Table 2, line 22, col. (c)
[3] Based on average station end-of-life dates in effect as of December 31, 2011 of: December 31, 2042 for Bruce A, December 31, 2014 for Bruce B (from page 3 of Att. 2 to Ex. L-2-1 Staff-19 and Ex. L-2-1 SEC-10)

The higher projected ARC depreciation expense in 2012 is due to the increase in the ARC for the Bruce facilities of $495.1M recognized on December 31, 2011 (Ex. H2-1-1, Table 3, top chart) as a result of the 2011 year-end ARO adjustment. Approximately $50M of additional ARC depreciation expense is estimated for 2012 as a result of the above adjustment, as provided at Ex. H2-1-2, p. 14, Chart 1.

SEC Interrogatory #03

Ref: H2/1/2, p.2

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

Interrogatory

Please provide a copy of the Agreement referred to in line 1. Please provide a reference to any determination by the Board that the obligations of the Applicant as set forth in the Agreement were prudently incurred. If no such determination has been made, please provide such government authorizations or directives, or other documents, as may exist which exempt the Agreement from prudence review by the Board.

Response

A discussed below, a copy of the Agreement is not relevant and has therefore not been provided.

The OEB has no jurisdiction to make a determination that the obligations of the Applicant as set forth in the Agreement were prudently incurred based on its findings in the EB-2007-0905 Decision with Reasons. In that Decision, the OEB stated:

- OPG's involvement with the Bruce stations is quite different from its involvement with Pickering and Darlington. For example, the Board (and previously the Province) regulates the prices for energy production from the prescribed facilities. In contrast, the lease payments charged by OPG to Bruce Power (and the prices charged for engineering and other services) **are the result of a commercial contract; they are not regulated by the Board or any other body.** (p.106). *[emphasis added].*

- In the Board's view, the fact that the net revenues related to OPG's unregulated Bruce lease are intended to mitigate the payment amounts for Pickering and Darlington does not lead to a conclusion that the Province must have intended that the Bruce revenues and costs be calculated as if OPG's investment in Bruce were subject to regulation. (p.107).

- The Board has no authority to set or review the terms of the lease between OPG and Bruce Power. (p. 99).

- O. Reg. 53/05 requires the Board to include OPG's revenues and costs for Bruce in the determination of the payment amounts for the

> Pickering and Darlington nuclear stations OPG forecast net Bruce revenues for the test period of $134.4 million, which OPG deducted from the nuclear revenue requirement to determine the payment amounts for Pickering and Darlington. This chapter addresses the question of whether OPG has used an appropriate method to calculate the revenues and costs for the test period for Bruce. (p. 99)

Quoting O. Reg. 53/05:

> The Board shall ensure that Ontario Power Generation Inc. recovers ***all the costs*** it incurs with respect to the Bruce Nuclear Generating Stations*." (p. 100) [emphasis added].*

As a result, the OEB has made no determination of prudence. OPG is not aware of any additional government authorizations or directives.

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.

Numbers may not add due to rounding.

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 #05

Ref: H2/1/2, p. 4

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

Interrogatory

Please provide the full calculation of the derivatives for each of 2011 and 2012, including all assumptions used (such as discount rates, or future annual average HOEP) and the sources of those assumptions, and file the report or reports of E&Y referred to. Please include a full, live version of the valuation model referred to. Please provide a copy of any reports or presentations to the Applicant's senior management or Board dealing with the calculation and/or impact of these derivatives, or dealing with any alternatives to derivative accounting considered.

Response

Exhibit L-1-1 Staff-10 c), Attachment 1 provides the assumptions used and the resulting valuations of the derivative liability at year-end 2011 and at Q2 2012 as well as the valuation of the increase in the derivative liability resulting from the extension of the accounting service life of the Bruce B units for an additional five years to 2019.

In addition to the information provided in L-1-1 Staff-10 c), Attachment 1 to this response is a memorandum to OPG's Chief Financial Officer discussing the Bruce Lease Supplemental Rent Claim for 2009. Appendix B to this memorandum is a paper titled Valuation of Bruce Power's Embedded Put Option dated February 11, 2010 (Attachment 1, pp. 9-15) ("Technical Document"). The Technical Document provides the underlying mathematical model used to compute the embedded derivative and assumptions used to derive the expected annual Average HOEP by removing a risk premium from OPG's proprietary forward price curve, together with an explanation as to the basis/sources of the assumptions. The derivation of the $118M fair value of the Bruce Lease derivative recorded in OPG's 2009 audited consolidated financial statements using the model described in the Technical Document is illustrated in Appendix A to Attachment 1 (page 8).

Attachment 2 to this response supplements the Technical Document (the "Supplement"). It provides the specific parameter values such as forward price data for HOEP used in the model to calculate the values provided in L-1-1 Staff-10 c). The Supplement includes the specific formulae and coding underlying the calculation and was prepared by OPG in responding to this question in order to allow the calculations to be fully understood.

In addition to the assumptions addressed by the above Technical Document and Supplement, and as discussed in L-1-1 Staff-10 c), the other assumptions provided in Attachment 1 to that interrogatory are the discount rate, which is used to determine the present value of the liability, and an estimated value for the Consumer Price Index ("CPI"), which is used to estimate the projected amount of the supplemental rent rebate for each future year. The source and rationale for the discount rate used is discussed in L-1-7 SEC-09. The estimated CPI values are based on publicly available information.

In the non-confidential version of this response, OPG has redacted certain information in the body of the memorandum related to its contractual relationship with Bruce Power L.P., as the disclosure of such information may affect OPG's commercial interests.

OPG also notes a typographical error contained in the memorandum. At page 5 of Attachment 1 there is a reference to "four units of Bruce A" in the last paragraph. The reference should be to "four units of Bruce B". As noted in sections 2 and 5 of the memorandum at pages 2 and 4 of the Attachment, respectively, and in L-1-1 Staff-8 b), the partial rent rebate provision in the Bruce Lease agreement does not apply to Bruce A units as long as they are subject to the Bruce Power Refurbishment Implementation Agreement between Bruce Power and the Ontario Power Authority.

For clarity, OPG's pre-filed evidence at Ex. H2-1-2, p. 4, lines 21-25 does not contain a reference to "report or reports of [Ernst & Young LLP] E&Y." As noted in that evidence, "… E&Y … reviewed the significant inputs used in the model, the model itself and the resulting valuation as part of the audit of OPG's financial statements …" As noted above, the requested information from the 2011 E&Y audit report to OPG's Board of Directors and/or committees thereof is provided as part of Attachment 3 as described in the following paragraph. E&Y's independent auditors' report on OPG's 2011 consolidated financial statements provided as part of OPG's year-end 2011 external financial report is found at page 61 of Ex. A3-1-1, Attachment 1.

Attachment 3 provides the requested information from reports by OPG's Senior Management and E&Y to OPG's Board of Directors and/or committees thereof that relate to the calculation and/or impact of the derivative and accounting for the derivative. Specifically, Attachment 3 includes the following:

Attachment	Document	Requested Information
3A	Year End Report 2009 for the Audit/Risk Committee and Board of Directors Meeting – March 2010	• Year End Results – Key Disclosures • Accounting and Tax Matters • Accounting and Tax Matters for Disclosure – Fourth Quarter 2009
3B	Ernst & Young 2009 Financial Statement Audit Results Report	• E&Y Communication to the Audit/Risk Committee of the Board of Directors • Areas of emphasis, critical policies, and judgments and estimates
3C	2010 First Quarter Report for the Audit/Risk Committee and Board of Directors Meetings – May 2010	• Accounting and Tax Matters and Other Project Updates • First Quarter Results – Key Disclosures and Recommendation • Accounting and Tax Matters for Discussion – First Quarter 2010
3D	Ernst & Young 2010 First Quarter Review Report for 31 March 2010	• E&Y Communication to the Audit/Risk Committee of the Board of Directors • Areas of focus and changes in accounting policies, judgments & estimates
3E	Ernst & Young 2010 Second Quarter Review Report for 30 June 2010	• E&Y Communication to the Audit and Finance Committee of the Board of Directors • Areas of focus and changes in accounting policies, judgments & estimates
3F	Ernst & Young 2010 Third Quarter Review Report for 30 September 2010	• E&Y Communication to the Audit and Finance Committee of the Board of Directors • Areas of focus and changes in accounting policies, judgments & estimates
3G	Ernst & Young 2010 Audit Results Report	• E&Y Communication to the Audit and Finance Committee of the Board of Directors • 2010 Audit Results – Critical policies, estimates and areas of audit emphasis
3H	Ernst & Young 2011 Audit Results Report	• E&Y Communication to the Audit and Finance Committee of the Board of Directors • Critical policies, estimates and areas of audit emphasis

OPG declines to provide a live version of its proprietary valuation model. As discussed in the OEB's Decision with Reasons in EB-2007-0905 (pp.111-112), the purpose of the Bruce Lease Net Revenues Variance Account is to ensure that OPG recovers its costs associated

The issue before the OEB is whether in making entries to the Bruce Lease Net Revenues Variance Account, OPG has appropriately calculated the costs and revenues associated with the Bruce Lease according to CGAAP. One element of this calculation is the reduction in supplemental rent associated with years when annual average HOEP is below $30/MWh, which must be valued as a derivative under CGAAP.

In response to this and other interrogatories, OPG has detailed the specifics of and all inputs to the calculations valuing the derivative and also has provided the documentation supporting this calculation and material from its auditors confirming both the calculations and that they are in accordance with CGAAP. This information will allow the parties and the OEB to understand and validate the calculations that OPG has performed.

Variations to these calculations as a result of the manipulation of a live model by SEC or any other intervenor are not relevant to this proceeding because they could only produce results that are different from OPG's actual costs of the Bruce Lease, which are the amounts recognized in OPG's financial statements and reviewed and accepted by its auditors as appropriate. Moreover, any changes to the input of the model would themselves need to be fully understood and validated.

As explained in L-1-1 Staff-07, no alternatives to derivative accounting were considered because derivative accounting as applied by OPG is required in accordance with CGAAP and USGAAP.

ONTARIO POWER GENERATION

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Donn Hanbidge
Chief Financial Officer

February 25, 2010

Robin Heard
VP Finance and Chief Controller

Bruce Lease Supplemental Rent Claim for 2009

Background

In May 2001, OPG entered into a Lease Agreement with Bruce Power for the Bruce Nuclear Power Development site, which included the Bruce-A and Bruce-B generating stations. The lease requires Bruce Power to pay OPG both a Base Rent and a Supplemental Rent tied to the operational Bruce-A and Bruce-B generating units. The initial calculation for Supplemental Rent involved a rate per megawatt hour (MWh) of production and included a compensation factor for the ultimate disposal of used fuel.

In January 2002 the Supplemental Rental clause of the Lease was amended to provide for a fixed annual Supplemental Rent per unit, adjusted annually by a Consumer Price Index (CPI) quotient. The amended clauses additionally provided that the Supplemental Rent rate would be significantly reduced if the annual arithmetic average hourly price of electricity in the Ontario market (i.e. HOEP) was below $30.00 per MWh.

Subsequent amendments to the lease in 2003 and 2005 have modified the conditions of Supplemental Rent payments but have retained the concept of reduced rental payments below the HOEP threshold of $30.00 per MWh. The amendment to the Lease in 2005 made the HOEP reduction applicable only to the Bruce B operating units; the Bruce-A units are not eligible for the HOEP as long as the agreement between Bruce Power and the Province of Ontario for the refurbishment of the Bruce-A units is in effect.

The 2009 HOEP closed out at $29.58/MWh. As a result, and in accordance with Schedule 3.1 Section 3.1.3.4 of the lease agreement, OPG received the annual Supplemental Rent Certificate from Bruce Power on January 19, 2010, claiming a return of Supplemental Rent overpayments for the Bruce generating facilities. The value of the claim is $72,826,903.80 including GST (approximately $69 million excluding GST). [redacted]

Actions Taken

Upon receipt of the transmittal a number of activities were completed to validate and substantiate the claim, including:

1. Notification of appropriate stakeholders of the receipt of claim.
2. Review of contract documents in order to confirm the validity of the claim.
3. Independent calculation of the value of the claim using terms and conditions of the contract and amendments.
4. Consultation with corporate stakeholders in order to obtain consensus of conclusions.
5. Accounting entries and financial reporting for 2009 rent rebate.
6. Quantification of future exposure for OPG from subsection 3.1.3.4 of Schedule 3.1 and appropriate accounting entries.

1. Notification of Stakeholders

Upon receipt of the claim the following individuals were notified:

Dietmar Reiner, Senior Vice President - IM&CS.

Steve Reeves, Controller - IM&CS

Law Division representatives were also notified as the transmission had been addressed to David Brennan, Senior Vice President – Law and General Counsel.

2. Review of Contract Documents

Terry Dereski of the Bruce Lease Management Office provided copies of the relevant sections of the Bruce Lease Agreement and amendments #1 - 3 that deal with Supplemental Rent. The original provisions of the Lease with respect to rent payments have gone through some modification in the amendments to the Agreement.

The amendment to the contract calls for Supplemental Rent to be paid in the amount of $25,500,000 per operating unit per year (as set in 2002) adjusted by CPI factors thereafter. Providing that the average arithmetic cost of power (HOEP) exceeds $30.00 per MWh, the full Supplemental Rent per operating unit at the Bruce A and B units will be payable is monthly installments by Bruce Power to OPG.

In the event that the average HOEP falls below $30.00 per MWh the annual Supplemental Rent is reduced to $12,000,000 per year per unit for each operational Bruce B unit. Supplemental Rent for operational Bruce A units remain unchanged as long as the Bruce Power Refurbishment Implementation Agreement ("Implementation Agreement") between Bruce Power and the Province remains in effect. This provision was introduced in the 3rd amendment to the lease subsequent to the execution of the BPRIA.

During the course of the year Bruce Power pays to OPG monthly the full Supplemental Rent, and then issues to OPG a Supplemental Rent Certificate in the month of January of the following year summarizing the rent payments for the 12 preceding months. At this point, Bruce Power assesses the HOEP for the preceding year and makes a claim for reimbursement of Supplemental Rent overpayments if the HOEP value is less than $30.00 per MWh

3. Independent Calculation of Claim Values

To validate the value of the claim, an independent calculation was performed by OPG. This calculation included the following steps:

1. Verification of the arithmetic average cost of power per MWh was conducted by consulting the HOEP values published by the IESO. Based on the monthly values reported the annual average for 2009 is $29.58 per MWh. A subsequent discussion on the terms of reference and the definitions of which average should apply concluded that the $29.58 average calculated by the IESO is the appropriate value for this calculation.
2. Validation of the CPI values used by Bruce Power. Published CPI values were obtained from the Bank of Canada and were compared to the values used. While some minor differences were found these differences were not material to the calculations.
3. A spreadsheet was created to calculate the total Supplemental Rental payments per the Lease Agreements in the event that the average rate is greater than $30.00 per MWh. The total value of payments was then reconciled to monthly payments received by Bruce Power in 2009.

4. Rental payments were then calculated using the rates assuming an average rate per MWh lower than $30.00. The difference between these two methods was calculated and found to be consistent with the Bruce Power claim value.

[redacted]

4. Consultation with Corporate Stakeholders

During the investigation process a consultation process was implemented by Mario Cornacchia to ensure that stakeholders were informed of the existence and progress of the claim and to elicit opinions and other input relative to the validity and payment of the claim.

Individuals included in the consultation process included:

Dietmar Reiner	Senior VP, IM&CS
Mario Cornacchia	Commercial Services, IM&CS
Terry Dereski	Commercial Services, IM&CS
Dennis Dodo	Nuclear Finance
Randy Leavitt	VP Nuclear Finance
Steve Reeves	Nuclear Finance
Dickson Harkness	Law Division
David Brennan	Law Division
Paul Burke	Planning – Energy Markets
Joanne Barradas	Financial Services
Robin Heard	VP Finance and Chief Controller

Through this process it was concluded that the claim submitted by Bruce Power was valid in terms of the contractual obligations set out in the Lease Agreements and that the value had been correctly calculated.

It was also recommended that OPG's shareholder would be consulted prior to final approval and payment of the claim.

5. Accounting Treatment and Financial Disclosure

The accounting treatment and disclosure issues have been broken down into the following discussion areas:

5.1 Regulatory Treatment

5.2 Accounting Treatment of Embedded Derivative

5.3 Bruce B Units

5.4 Bruce A units 3-4

5.5 Valuation Model

5.6 Bruce Lease Net Revenue Variance Account

5.7 HB3862 disclosure

5.8 Tax Impact

5.9 Future Period Impact

The payment will be made pending consultation with OPG's shareholder.

The journal entry recorded reflected a reduction to lease revenue of $69 million. The reduction in revenue reflected Bruce's claim for the lower Supplemental Rent payments for 4 units at the Bruce B nuclear generating station. This reduction of $69 million was determined by subtracting the amount collected (excluding GST) for the Bruce B units minus $48 million ($12 million per unit for four Bruce B units).

This calculation excludes Bruce A. This is because the Supplemental Rent for the Bruce A units remains unchanged unless the Implementation Agreement was terminated. Currently, there is no indication that the Implementation Agreement will be terminated; thus there was no claim on the Bruce A units for 2009.

5.1 Regulatory Treatment

Although the Bruce generating stations are not prescribed facilities, the income and expenses related to the Bruce generating stations are included in the determination of OPG's regulated prices. Specifically, forecasted Bruce lease revenues were applied against OPG's revenue requirement. In the OEB's 2009 decision, the OEB authorized a Bruce Lease Net Revenue Variance account. Under the Bruce Lease Net Revenue Variance account, OPG is required capture in a variance account the difference between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power. Accordingly, OPG has recorded an offsetting regulatory asset of $69 million for the 2009 reduction in Supplemental Rent.

5.2 Accounting treatment of embedded derivative

In accordance with CICA HB Section 3855, Financial Instruments – Measurement and Recognition, this adjustment to the Supplemental Rent would be considered an embedded derivative that needs to be bifurcated from the lease agreement. Embedded derivatives are measured and recognized at fair value in the statement of income, which is in addition to the current claim by Bruce Power already recognized for 2009.

This embedded derivative is similar to a series of put options written by OPG requiring OPG to "pay" Bruce Power an amount that is equal to the normal Supplemental Lease payment minus $12 million with a strike price linked to a HOEP price (arithmetic average) of $30/MWh for that year, which is exercisable by Bruce Power every year for the duration of the lease.

The value of this embedded derivative is determined based on a number of factors including forward price curves for future years (excluding the impact of any risk premium included in the forward prices), the volatility of the HOEP price, forecasted consumer price index, and a discount rate. Further details of the pricing models and inputs will be discussed later in this memo. The following discusses which of the options are included in the valuation model.

5.3 Bruce B Units

Supplemental lease payments are only applicable in years where the units are operating at any time during the year. Consistent with OPG's assumption for depreciation purposes, Bruce B units have an average useful life of 2014. To be consistent with this assumption, OPG has concluded that the valuation would only be applicable to the four units up to 2014. This is because, if the units are not operating, OPG would not collect Supplemental Rent from Bruce Power for those units and the embedded derivative would have no value.

In addition, based on the current forecast, the forward price beyond 2014 is estimated to be $45/MWh or higher, hence options value beyond 2014 will likely have a value of close to zero. In the future, if the useful life of the Bruce B generating station for accounting purposes is extended, the options related to years beyond 2014 will need to be evaluated.

5.4 Bruce A Units 3 and 4

For Bruce A Units 3 and 4, the $30/MWh trigger is only effective if the Implementation Agreement related to the Bruce A refurbishment is terminated. Currently, however, there is no indication that the Implementation Agreement will be terminated. If the Implementation Agreement were to be terminated in the future, the Bruce A option would be valued the same way as the Bruce B options as discussed above.

5.5 Valuation Model

A write-up of the valuation model is included in Appendix A and Appendix B. The model was prepared by Energy Markets and reviewed by the Corporate Portfolio Risk Management group in Finance. The basic steps to estimate the fair value of the options are as follows:

1) The valuation model estimates the probability of the strike price being met in each year;

2) The probability for the year is then multiplied by the maximum exposure for each year;

3) The result of the probability-adjusted value is discounted at OPG's credit adjusted rate;

4) The sum of all present values is the present value for the series of the options.

As of December 31, 2009, the sum of all present values for four units of Bruce A up to year 2014 is estimated to be $118 million. The fair values of the embedded derivatives are recorded in long-term accounts payable and as a reduction to revenue (Regulated – Nuclear Generation segment).

OPG uses market-based variables as input into the valuation to the extent those variables are available. The fair value of the derivative is calculated based on a number of inputs and the key inputs are listed as follows:

To calculate the probability of the strike price being met: Forward curve for electricity for Ontario[1], estimation of risk premium included in the forward curve value (to remove risk premium), and calibration of volatility.

To calculate the maximum exposure: Supplemental Rent and the Expected Consumer Price Index

To calculate present value: OPG's credit adjusted rate (In accordance with EIC 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, OPG is required to include its credit risk for the valuation of a financial liability).

To determine which options to include: Number of Units that operate during the year and Useful life of the stations.

5.6 Bruce Lease Net Revenue Variance Account

As discussed in the above, OPG is required to capture in a variance account the difference between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power. Accordingly, OPG has recorded a regulatory asset of $118 million in the Bruce Lease Net Revenue Variance account.

5.7 HB3862 Disclosure

The estimation of risk premium requires the use of an assumption of implied profitability probability of 80%. This assumption is not a significant input and is not based on observable market information. Hence, the instruments are classified as level 3 for fair value disclosure purposes. In accordance with HB3862, OPG is required to present a sensitivity analysis for instruments that are classified at level 3.

The sensitivity analysis was performed by varying key assumptions to a reasonably possible degree. OPG varied the profitability probability range from 70% - 90% and volatility sigma from 0.012 to 0.018. These ranges are determined based on professional judgment of what is reasonably possible given the knowledge of the market and variability in the surrounding environment. By varying these variables, OPG disclosed sensitivity of an increase of $45 million or a decrease of $44 million, respectively.

5.8 Tax Impact

As a result of the OEB's prescribed method for calculating the income tax related to Bruce, which differs from OPG's income tax method, OPG recorded $5 million of income tax recovery in 2009 related to the $69 million. The income tax recovery related to the fair value of the embedded derivative is approximately $6 million

1. Given the illiquidity in the Ontario market for electricity forward contracts and electricity related options, forward price curves and volatilities are estimated based on limited actual transactions, bid/ask spreads posted from time to time, and inferred prices from other liquid hubs.

5.9 Prior Period Impact

Upon review of the material there is no prior period impact caused by this issue. Both parties have been applying the contract in strict accordance with its terms, and 2009 is the first year the HOEP value has dropped below $30 per MWh.

6.0 Ongoing Accounting, Reporting, and Internal Control Processes

Concurrent with the activities listed in this document Nuclear Finance has undertaken a study to improve the level of control and management reporting for the Bruce Lease Management Office. Recommendations of the study performed include the following:

1. Recommended accountabilities should be validated and accepted by identified OPG business units, including Finance, Corporate Real Estate, Law Division, Business Services & Information Technology, Risk Services, Regulatory Affairs & Corporate Strategy, and Nuclear business units with specific accountabilities.
2. Specific requirements for regular reporting should be outlined for financial results, strategic decisions, and emerging issues in order to ensure the relationship is well managed and obligations are discharged in a timely and effective manner.

[redacted]

4. Governance should be created or updated to reflect accepted accountabilities and reporting requirements. In addition, guidelines should be developed to assist OPG business units who interface with Bruce Power or receive requests outside the existing agreements. These guidelines should address materiality provisions and limits requiring formal agreement or amendment.
5. With a firm understanding of the accountabilities of OPG business units, reporting requirements and the strategic goals of the BLMO, resource levels should be reviewed for adequacy. If transactional responsibilities are to be retained by the BLMO, additional resources may be required to adequately fulfill oversight responsibilities.
6. With regard to organizational placement of the BLMO, three organizations should be considered:
   (i) Nuclear Commercial Relations,
   (ii) Corporate Affairs, and
   (iii) Corporate Business Development.

Dedicated financial support within the appropriate Controllership is also recommended.

Organizational alignment with a non-operational group will enhance BLMO capabilities to coordinate and drive the discharge of OPG obligations and service new requests. In addition, periodic reports to OPG Senior Management (and the OEB) could be appropriately integrated with other corporate initiatives.

RLeavitt.

Randy Leavitt
VP Nuclear Finance

Appendix A

Year Ended December 31, 2009
Bruce Emedded Derivative Estimate

Assumptions:	**Input fields**
Supplemental Rent for 2009	117,358,596
Reduced Supplemental Rent	12,000,000
Number of Units	4
Total Reduced Supplemental Rent	48,000,000
CPI - 2010	1.50%
CPI - 2011 to 2014	2.00%
CPI - 2015 to 2018	2.50%
Probability 2010 - 2014	50%
Probability 2015 - 2018	0%
Discount Rate	4.12%

Summary of Results:

Maximum refund (undiscounted)	736,703,307
Maximum value of derivative (PV)	599,494,478
Expected value of derivative (undiscounted)	132,000,605
Expected value of derivative (PV)	**117,973,985**

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Full Supplemental Rent	119,118,975	121,501,354	123,931,382	126,410,009	128,938,209	132,161,665	135,465,706	138,852,349	142,323,658	1,168,703,307
Reduced Supplemental Rent	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	432,000,000
Maximum refund	71,118,975	73,501,354	75,931,382	78,410,009	80,938,209	84,161,665	87,465,706	90,852,349	94,323,658	736,703,307
Probability	41.66%	41.72%	36.71%	27.51%	27.51%	0.00%	0.00%	0.00%	0.00%	
Maximum Fair Value of Derivative (100% probability)	68,302,783	67,795,546	67,263,588	66,708,803	66,132,988	66,043,758	65,918,631	65,759,642	65,568,738	599,494,478
Total expected adjustment	29,630,350	30,663,908	27,877,529	21,566,718	22,262,100	-	-	-	-	132,000,605
PV of expected adjustments	**28,457,038**	**28,283,511**	**24,695,227**	**18,348,294**	**18,189,916**	**-**	**-**	**-**	**-**	**117,973,985**

Valuation of Bruce Power's Embedded Put Option

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1 Introduction

Bruce Power negotiated an embedded put option in their long-term lease contract for the Bruce A and Bruce B nuclear stations with Ontario Power Generation (OPG). Whenever the arithmetic average of the Hourly Ontario Electricity Price (HOEP) over a calendar year falls below 30$, they can exercise a provision in their contract with OPG that entitles them to a rebate on part of the rent for that year. For the calendar year 2009 this rebate is about 72.8 M$. This option is in place for the duration of the lease until the end of the year 2018.

The embedded put option constitutes an obligation for OPG that needs to be valued in the companies financial statements. The question to be answered is:

> "What is the fair value of the options for 2010–2018, as of December 31st, 2009?"

We shall answer this question by constructing a model from which the probability that the option is exercised for a given year can be derived. Multiplying these probabilities by the maximum exposure for each year and summing the discounted values gives the Present Value (PV) that is needed for the company's financial statements. This value needs to be updated during the course of the year for the quarterly financial statements.

2 Analysis

This contingent claim has elements of the following option types:

1. **Binary Put.** Such a contract pays a pre-determined, fixed amount, if the value of the underlying asset falls below a certain level,

2. **Asian Option.** Such a contract is written on the arithmetic average of the value of the underlying asset over a specific time period,

3. **Forward Starting Option.** An option where part of the components that determine the value of the option are already known when the contract is entered into.

The underlying asset on which the option is written, is the Hourly Ontario Electricity Price (HOEP). For notational brevity and to adhere to standard financial notation, we will denote this as a spot-price $S(t)$, where the time t is measured in hours. The average price over the hours $t = 1, \ldots, T$, where T is 8760 (or 8784 for a leap year), is given by

$$\bar{S} = \frac{1}{T} \sum_{t=1}^{T} S(t). \tag{1}$$

The option that Bruce Power holds is an annual recurring, binary put on $\bar{S}$, with a strike of $K = 30\$$ and notionals in the order of 72.8M$.

2.1 Model

Rather then to propose a model for the spot-price process and its evolution, we have chosen to directly model the annual, arithmetic average of the spot price. The reasons for this are given in greater detail in Section 7.1, but boil down to the generally acknowledged difficulty of accurately modeling hourly electricity prices, certainly over longer periods of time, and the calibration of the model parameters.

The traded instruments for electricity in the Ontario market are limited to forward contracts only; options on electricity do not exist. The fact that one can synthesize the annual average over the spot price by purchasing a 7×24 forward contract over the same period, for a volume of 1 MW, forms the basis of our model. The power that we receive over that period, by paying a forward price of F per MW over a period of T hours, has a total market value of $\sum_{t=1}^{T} S(t)$. So, for a payment of $F \times T$, we receive $\sum_{t=1}^{T} S(t)$, and this establishes a connection between the forward price and the arithmetic average of the spot price over a calendar year. We formally relate the two through the following model:

$$\bar{S} \cong F e^{-\lambda - \frac{1}{2}\sigma^2 + \sigma Z}, \tag{2}$$

where the symbol $\cong$ denotes equality in distribution, F is the latest observed forward price, $\lambda > 0$ represents a discount factor, σ is a standard deviation, and Z is a standard normal variate, so that $\bar{S}$ follows a lognormal distribution. The expected value of $\bar{S}$ is given by:

$$\mathsf{E}\,\bar{S} = F e^{-\lambda}. \tag{3}$$

This incorporates the well-documented fact that the forward price in electricity markets is not an unbiased estimator of the expected (average) spot price, and incorporates a risk premium. Moreover, when the distribution of spot prices exhibits positive skewness and there is a risk of price spikes, the forward contract trades at a risk premium over the expected spot. Section 7.2 discusses this in more detail. Examining Table 1, we can see that the prices in Ontario are positively skewed and experience large price spikes, so that the assumption of a positive risk premium is plausible.

As there is no options market, from which one can derive implied volatilities, we are limited to the historical forward-price series to quantify the uncertainty around the annual average. For the standard deviation σ of the logarithmic of the annual average for the next calendar year (2010), we assume that this is the same as the standard deviation that the logarithm of the forward price would experience over a period of a calendar year. With the usual assumption that there are 250 trading days in a year, this implies that

$$\sigma = \sqrt{250}\,\sigma_F, \tag{4}$$

where σ_F is the standard deviation of the daily log-returns of the forward. For all the subsequent calendar years (2011 and beyond), we use $2 \times 250 = 500$ trading days, as the electricity price process is mean-reverting and thus the volatility will stabilize for longer periods of time, which we assume occurs after two years.

2.2 Exercise Probability

Under model (2) for the distribution of the annual average spot price, we can determine the probability that the option will be exercised for a particular year as the expected value of a \$1 binary put option B, with strike $K = 30\$$:

$$\mathsf{E}\, B = \mathsf{E}\ \mathbf{1}(\bar{S} < K) = \mathsf{Prob}\,(\bar{S} < K) = \mathsf{Prob}\,(F\, e^{-\lambda-\frac{1}{2}\sigma^2+\sigma Z} < K) = \Phi\left(\frac{\ln(K/F) + \lambda + \frac{1}{2}\sigma^2}{\sigma}\right), \tag{5}$$

where Φ is the cumulative density function (cdf) of the standard normal distribution.

2.3 Risk Premium

The risk premium in the forward is estimated by means of the following trading strategy: at the start of the calendar year, we sell a forward at price F. During the calendar year we have to deliver the commodity at the spot price, so that the profit or loss at the end of the year is given by:

$$\text{P\&L} = F \times T - \sum_{t=1}^{T} S(t).$$

The probability of not loosing money on this trade is given by

$$\mathsf{Prob}\,(\text{P\&L} \geq 0) = \mathsf{Prob}\,(\bar{S} \leq F) = \cdots = \Phi\left(\frac{\lambda}{\sigma} + \frac{1}{2}\sigma\right).$$

If we insist that we need a minimum probability p, so that we do not loose money on the trade, we can determine the discount factor as:

$$\lambda = \Phi^{-1}(p)\sigma - \frac{1}{2}\sigma^2. \tag{6}$$

This gives the (relative) risk premium, embedded in the forward price, as:

$$\frac{F - \mathsf{E}\,\bar{S}}{F} = 1 - e^{-\lambda} \tag{7}$$

Note that p is a reflection of the risk-aversion of the trader and the market liquidity. In a market that is not very liquid, there would not be many trade opportunities to off-set a trade that lost money, and hence p would be relatively high. The more liquid a market is, the more possibilities there are to recover any losses, and consequently, the lower p would be. Note that, by (6), the risk premium λ also incorporates the volatility of the traded asset.

3 Data and Model Inputs

This Section describes the data that was used to calibrate the volatility of the forward price series, and the assumption that was made for the required probability of a trade being profitable.

3.1 Daily Volatility of the Forward

The data for the analysis was provided by the Market Risk group of Energy Markets. This comprised the historical, daily forward prices for Cal-2008, Cal-2009, and Cal-2010, as recorded on business days, over the preceding calendar years, 2007, 2008, and 2009, respectively. A volatility estimate for each time series was estimated as the standard deviation of the equally weighted, log returns. This resulted in the following estimates:

	Cal-2008	Cal-2009	Cal-2010
$\hat{\sigma}_F$	0.014528	0.016571	0.015395

We note that these estimated volatilities are very similar, and support the simplifying assumption that we can treat all forward price series as having the same daily volatility. Hence, we will take the rounded average of these three volatilities as the final daily, volatility estimate of the forward price: $\sigma_F = 0.015$.

3.2 Required probability of a trade being profitable

It was judged that $p = 0.9$, would be too high, as it would probably price any potential transactions out of the market, and that $p = 0.7$ would be too low in a very thin and volatile market to have a reasonable profit expectation. In the end, we made a judgment call, and have chosen $p = 0.8$, as a reasonable value.

4 Sanity Check

To see what the effects of the key parameters (σ and p) of the model are, we have varied these parameters over a reasonable range and computed what the corresponding risk-premium for a Cal-2010 forward would be. The results are displayed in Table 2 and Table 3. Where the former gives the risk premium, relative to the forward price, as per (7), and the latter the risk premium, relative to the spot price.

The parameter choice of $\sigma = 0.015$ and $p = 0.8$ results in a risk premium, relative to spot price, of 18.7%. This value is comparable to the results from the market studies that OPG commissioned before market opening.

4.1 Internal Validation

Prior to market opening in Ontario on May 1st, 2002, OPG conducted several studies on how to construct forward curves and what risk premiums to charge. The findings [2, p. 18] were that there was a 20% premium based on forwards over historical spots. Electricity industry consultant, C. Pirrong, reached similar conclusions. A 15% premium was recommended to and approved by the Risk Oversight Committee (ROC).

5 Risk-Neutral Probabilities

We can now apply the model to give an estimate for the risk-neutral probabilities that the put option will be exercised. Combining the last quoted forward prices in 2009, for the 7×24 contracts for the calendar years 2010–2014, with the parameter estimates, previously derived, gives

	2010	2011	2012	2013	2014
FWP	\$38.50	\$42.68	\$44.58	\$48.61	\$48.61
$\mathsf{E}\,\bar{S}$	\$32.44	\$34.04	\$35.56	\$38.78	\$38.78
Prob.	41.7%	41.7%	36.7%	27.5%	27.5%

6 Quarterly Valuation

At the start of the period of the exposure, the probability that the option will be exercised is given by (5). For the probability during the period, when time has passed, we need to account for the fact that some portion of the average is already known, and that this reduces the uncertainty around the probability of exercise and this has an effect on the option value. At time t_1, the prices $S_1, S_2, \dots, S_{t_1}$ are known, and the average can be decomposed into a known and unknown part:

$$\bar{S} \times T = \sum_{t=1}^{T} S(t) = \sum_{t=1}^{t_1} S(t) + \sum_{t=t_1+1}^{T} S(t).$$

We can relate the forward price F_1, of a 7×24 over the period $t_1 + 1, \dots, T$, to the sum of the spot prices over that period in exactly the same manner as we have done for the entire calendar year. This allows us to generalize equation (2) to

$$\bar{S} \cong \frac{t_1}{T}\bar{S}_1 + \frac{T - t_1}{T} F_1 e^{-\lambda_1 - \frac{1}{2}\sigma_1^2 + \sigma_1 Z},$$

where $\bar{S}_1$ is the average over the time period $t = 1, \dots, t_1$, which is known at t_1. The other variables are the latest observed forward price F_1, the discount factor $\lambda_1 > 0$, and the standard deviation σ_1, all for the remainder of the year; the period $t = t_1 + 1, \dots, T$. These can all be computed in a fashion similar to the parameters for the distribution of the annual average.

By the same mechanism as before, we can determine the probability that the option will be exercised, given the information up to t_1, as an expectation:

$$\mathsf{E}\, B_1 = \Phi\left(\frac{\ln\left(\frac{KT - t_1\bar{S}_1}{(T-t_1)F}\right) + \lambda_1 + \frac{1}{2}\sigma_1^2}{\sigma_1}\right).$$

As the option is typically revalued for the quarterly reports, the formula simplifies to:

$$\mathsf{E}\, B_i = \Phi\left(\frac{1}{\sigma_i}\ln\left(\frac{4K - i\bar{S}_i}{(4-i)F_i}\right) + \frac{\lambda_i}{\sigma_i} + \frac{1}{2}\sigma_i\right), \quad i = 0, 1, 2, 3,$$

where $\mathsf{E}\, B_i$ is the probability of exercise, when i quarters have passed, and F_i and σ_i are the forward price and implied volatility for a 7×24 forward contract over the remaining quarters. Note that for $i = 0$, at the start of the calendar year, this formula reduces to (5). Also note that, although we have taken a quarterly valuation as typical, this is easily adapted to a monthly frequency.

7 Discussion and Motivation

This Section provides a more in-depth discussion and motivation behind the modeling choices that have been made.

7.1 Spot Price Modeling

When the underlying asset follows a well-defined stochastic process, such as a Geometric Brownian Motion (GBM), an Ornstein-Uhlenbeck (OU) mean-reverting process, or any one- or multi-factor model, one can use standard approaches to value Asian-type options. For a GBM one can use moment-matching techniques to derive a proxy distribution, and for any of the more general models one can use Monte-Carlo techniques. Unfortunately, the hourly spot-price for electricity does not follow a simple stochastic process. In fact, it is general acknowledged that electricity is one of the most difficult asset classes to model. The main reasons are that electricity is a non-storable commodity, and that supply and demand must be managed and balanced in real time. The first means that standard arbitrage arguments to price derivatives that rely on buy-and-hold strategies and replication arguments do not apply. The second implies that the spot electricity price can exhibit large price spikes, as temporary surges in demand are satisfied by flexible but potentially, very expensive generation.

The result is that the hourly electricity price is determined by a host of fundamental factors, reflecting load patterns that translate into strong diurnal, weekly and seasonal price patterns, and cause strong mean-reversing in the electricity prices. Any realistic stochastic model for the spot price of electricity must also incorporate price spikes that reflect the inelasticity of demand. Weron [6, Ch. 4] gives an overview of various modeling approaches for the spot price. Another feature that has only started to occur in the last few years in the Ontario market are negative prices, due to low demand and a surplus of generation, which leads inflexible base-load generation, such as nuclear to offer at negative prices in order to avoid having to shut-down. This phenomenon has been observed much earlier in more mature markets, that have a sizeable amount of renewable generation in their generation mix, see Sewalt and de Jong [5]. The feature of negative prices is of particular importance in our setting, as these prices are a major contributing factor to the average HOEP for 2009 being as low as $29.517. With this in mind, it is important to note that in almost all of the spot-price models in the literature, it is tacitly assumed that negative prices cannot occur. Finally, even if an appropriate model can be formulated, one still has to calibrate a large number of parameters, which is challenging in a stationary market, let alone in a market such as Ontario where the generation mix is changing.

For all of the above reasons we have chosen not to use the approach of modeling the evolution of the spot price through some stylized stochastic process. This ruled out a straightforward Monte Carlo simulation approach.

7.2 Risk Premium

If we were dealing with a normal financial asset, the forward price would be equal to the discounted, expected value of its stochastic counterpart. However, this is not the case for electricity forwards. It is well documented in the literature that the forward price in electricity markets is not an unbiased estimator of the spot price, and incorporates a risk premium. Bessembinder and Lemmon [1] study the PJM market and find that the risk premium, defined as the difference between the forward and expected spot price over the period that the forward covers, increases when the spot power-price distribution exhibits positive skewness. Longstaff and Wang [4] also find significant forward premia in electricity forward prices. They also find that forward premia are positively correlated with skewness of the spot price distribution. Diko et al. [3], using data from the three major and most liquid continental European energy markets: the Dutch, German, and French electricity markets, also show significant risk premia in the forward price.

References

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[5] Michael Sewalt and Cyriel de Jong. Negative prices in electricity markets. *Commodities Now*, pages 74–77, June 2003.

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	2003	2004	2005	2006	2007	2008	2009
Mean	54.045	49.950	68.492	46.383	47.806	48.830	29.517
SDev	35.929	21.892	40.739	23.984	24.658	29.762	30.864
Skewness	2.979	1.819	2.871	5.450	1.563	2.591	30.214
Kurtosis	22.323	11.804	20.540	106.719	12.803	25.394	1654.762
Min	11.540	5.250	8.600	-3.100	-0.400	-34.000	-52.080
Max	548.520	340.450	639.970	699.650	436.530	563.620	1891.140

Table 1. HOEP statistics

$\sigma \backslash p$	0.70	0.75	**0.80**	0.85	0.90
0.010	6.8%	9.0%	11.4%	14.0%	17.3%
0.012	7.8%	10.4%	13.2%	16.4%	20.2%
0.014	8.8%	11.7%	14.9%	18.5%	22.8%
0.015	9.2%	12.4%	**15.8%**	19.6%	24.1%
0.016	9.6%	12.9%	16.5%	20.6%	25.3%
0.018	10.3%	14.1%	18.0%	22.5%	27.7%
0.020	10.9%	15.1%	19.4%	24.3%	29.9%

Table 2. Risk Premium embedded in a Cal-2010 Forward (relative to the Forward price)

$\sigma \backslash p$	0.70	0.75	**0.80**	0.85	0.90
0.010	7.3%	9.9%	12.8%	16.3%	20.9%
0.012	8.5%	11.6%	15.2%	19.6%	25.3%
0.014	9.6%	13.3%	17.6%	22.7%	29.6%
0.015	10.1%	14.1%	**18.7%**	24.3%	31.8%
0.016	10.6%	14.9%	19.8%	25.9%	33.9%
0.018	11.5%	16.4%	22.0%	29.0%	38.3%
0.020	12.3%	17.7%	24.1%	32.0%	42.7%

Table 3. Risk Premium embedded in a Cal-2010 Forward (relative to the spot price)

Bruce Embedded Derivative — Technical Disclosure.

The references in this document are to Equations and Sections in the Technical Document. Words in **boldface** indicate corresponding variable names and constants in the mathematical model, described in the Technical Document.

The exercise probability **EB** of the binary option is calculated as per Eqn (5), with the discount factor **lambda** determined as per Eqn (6). Combining these two equations, this can be coded in Excel, as follows:

EB = NORMSDIST(NORMSINV(**p**)+LN(**K**/**F**)/**sigma**).

As described in Section 3.2, the value for **p** is taken as p=0.8, and is fixed throughout and used equally for all valuations. The strike price **K** is $30, as per the lease agreement. The forward price **F** is the price for a 7x24 forward contract over the relevant calendar year, as seen on the valuation date. The aggregate volatility **sigma** is computed as the square root of the number of trading days **NTD** (that are left to the expiry of the option), multiplied by the historical daily volatility. The aggregate of volatility is capped at 500 trading days, as explained towards the end of Section 2.1.

The discount factor **lambda** is calculated as per Eqn (6). This can be coded in Excel as follows:

lambda = NORMSINV(**p**)***sigma** – ½***sigma**^2.

The discount factor determines the risk premium that is embedded in the forward price and is calculated as per Eqn (7). This can be coded in Excel as follows:

Risk Premium (in %)= 100*(1-EXP(-**lambda**)).

The expected annual average HOEP can then be computed by stripping out the risk premium from the forward price, as per Eqn (3). This can be coded in Excel as follows:

Exp HOEP = **F***EXP(-**lambda**).

The parameter values that were used in the valuations that were provided are given in the following tables.

Valuation Date Sat 31-Dec-2011	Forward Price F	Nr Trading Days NTD	Daily Volatility	sigma	lambda	Strike Price K	Prob of Exercise EB
			Bruce Embedded Derivative Valuation Parameter Values				
2012	$ 27.606	250.0	0.013792	0.218075	0.159758	$ 30.00	88.93%
2013	$ 29.290	500.0	0.013792	0.308405	0.212003	$ 30.00	82.10%
2014	$ 31.814	500.0	0.013792	0.308405	0.212003	$ 30.00	74.26%

Valuation Date Fri 29-Jun-2012	Forward Price F	Nr Trading Days NTD	Daily Volatility	sigma	lambda	Strike Price K	Prob of Exercise EB
			Bruce Embedded Derivative Valuation Parameter Values				
2012	$ 22.203	126.4	0.011659	0.131061	0.101715	$ 30.00	99.91%
2013	$ 22.028	376.4	0.010945	0.212336	0.156163	$ 30.00	98.92%
2014	$ 24.219	500.0	0.010945	0.244740	0.176029	$ 30.00	95.69%

Valuation Date Fri 29-Jun-2012	Forward Price F	Nr Trading Days NTD	Daily Volatility	sigma	lambda	Strike Price K	Prob of Exercise EB
			Bruce Embedded Derivative Valuation Parameter Values **Life Extension**				
2015	$ 27.216	500.0	0.010945	0.244740	0.176029	$ 30.00	89.24%
2016	$ 29.542	500.0	0.010945	0.244740	0.176029	$ 30.00	81.71%
2017	$ 30.660	500.0	0.010945	0.244740	0.176029	$ 30.00	77.42%
2018	$ 32.120	500.0	0.010945	0.244740	0.176029	$ 30.00	71.32%
2019	$ 34.287	500.0	0.010945	0.244740	0.176029	$ 30.00	61.64%

Year End Results – Key Disclosures

MD&A

- Reduction in Bruce lease revenue due to low average HOEP and offset by corresponding increase in regulatory variance account (page 7)

Accounting and Tax Matters

Bruce Supplemental Agreement

- Conditional obligation based on HOEP accounted for as an embedded derivative.

3. Bruce Supplemental Rent Adjustment and Embedded Derivatives

According to the existing lease agreement with Bruce Power, the annual Supplemental Rent for each Bruce B unit is $25.5 million from January 1, 2002, escalated by the Consumer Price Index. However, if the annual arithmetic average of the Hourly Ontario Electricity Price ("HOEP") for a calendar year is less than $30/MWh, the Supplemental Rent for that calendar year is reduced to $12 million for each Bruce B unit.

For the first time since the inception of the lease agreement, in 2009, the HOEP fell below the $30/MWh threshold. As a result, there is a refund owing to Bruce Power of $69 million, which is the difference between the Supplemental Rent paid and the reduced Supplemental Rent of $12 million per unit. OPG has accrued a payable of $69 million and reduced the Bruce lease revenue for 2009. The reduction to the Bruce lease revenue was offset by a corresponding increase in the Bruce Lease Net Revenue variance regulatory asset. The establishment of a variance account to capture differences between actual and forecasted results associated with the nuclear generating stations on lease to Bruce Power was authorized by the OEB.

Furthermore, the impact of this Supplemental Rent adjustment clause in future periods is accounted for as a put option written by OPG, which requires OPG to pay Bruce Power an amount that is equal to the annual Supplemental Lease payment minus $12 million per unit with a strike price linked to an HOEP of $30/MWh. This feature meets the definition of a derivative that must be accounted for separately, since HOEP is not closely related to the lease contract. Derivatives, including embedded derivatives, are recognized at fair value with changes in fair value recorded through net income. Prior to 2009, OPG valued this embedded derivate at zero as the HOEP remained significantly higher than $30/MWh. OPG has re-valued this derivative at the end of 2009 and recorded a payable of $118 million. The derivative was recorded against Bruce lease revenue. The decrease in Bruce lease revenue was also offset by the Bruce Lease Net Revenue variance regulatory asset.

3B. Ernst & Young 2009 Financial Statement Audit Results Report

ERNST & YOUNG

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The Audit / Risk Committee of the Board of Directors
Ontario Power Generation Inc.

24 February 2010

Dear Members of the Audit / Risk Committee:

We are pleased to present the results of our audit of the financial statements of Ontario Power Generation Inc. ("OPG") This report also includes the status of our final procedures, which we anticipate will be completed on or about 4 March 2010.

The audit is designed to express an opinion on the 2009 consolidated financial statements as of 31 December 2009. In accordance with professional standards, we obtained a sufficient understanding of internal control to plan the audit and to determine the nature, timing and extent of tests to be performed. However, we were not engaged to and we did not perform an audit of internal control over financial reporting.

At Ernst & Young, we continually evaluate the quality of our professionals' work, with a focus on our goal to deliver remarkable client service. We strive to provide you with audit services of the highest quality that will meet or exceed your expectations, and we encourage you to participate in the Assessment of Service Quality (ASQ) process to provide your input on our performance. The ASQ process is a critical tool in enabling us to continually monitor and improve the quality of our audit services to OPG.

This report is intended solely for the information and use of the Audit Committee, Board of Directors and management. It is not intended to be, and should not be, used by anyone other than these specified parties.

We look forward to meeting with you to discuss the contents of this report and answer any questions you may have about the results of our audit.

Sincerely,

Ernst & Young LLP

Chartered Accountants
Licensed Public Accountants

2009 audit results (cont'd)

Areas of emphasis, critical policies, and judgments and estimates

Area	Ernst & Young comments on quality of accounting policy and application / Area of emphasis	Significant judgments and estimates
Investments and financial instruments **Description** The Company values certain investment and financial instruments (available for sale, trading and other assets and liabilities that the Company may elect to carry at fair value) at fair value, measured in accordance with CICA 3855 **GAAP basis** CICA Section 3855, *Financial Instruments – Recognition and Measurement*	*Bruce Lease Embedded Derivative* Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/MWh. This clause was actually triggered in 2009, resulting in a claim amount of $72.8 million, comprised of $69.3 million of reduced rent and $3.5 million of GST to be refunded. In accordance with CICA 3855, the adjustment to the Supplemental Rent is considered an embedded derivative that needs to be bifurcated from the lease agreement and fair valued. We have reviewed the valuation model developed by OPG's Energy Markets group, and concur with the fair value amount recorded of $118 million. The amount recorded has been offset against the Bruce revenue variance account, thus there is no impact on net income.	*Bruce Lease Embedded Derivative* The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index, and a discount rate.

Filed: 2013-01-14
EB-2012-0002
L-1-7 SEC-05 Attachment 3
Page 5 of 16

Accounting and Tax Matters and Other Project Updates

Bruce Supplemental Agreement and Embedded Derivative

- Conditional obligation based on HOEP accounted for as an embedded derivative. Derivative value increased by $95 million to $213 million as at March 31, 2010
- Income impact offset by Bruce Lease Net Revenues Variance Account

First Quarter Results – Key Disclosures and Recommendation

MD&A

- Reduction in Bruce lease revenue by change in fair value of embedded derivative due to lower average HOEP forward prices, and offset by corresponding increase in regulatory variance account (page 6)

1. Bruce Supplemental Rent Adjustment and Embedded Derivative

According to the existing lease agreement with Bruce Power, the annual Supplemental Rent for each Bruce B unit is $25.5 million from January 1, 2002, escalated by the Consumer Price Index. However, if the annual arithmetic average of the Hourly Ontario Electricity Price ("HOEP") for a calendar year is less than $30/MWh, the Supplemental Rent for that calendar year is reduced to $12 million for each Bruce B unit. The impact of this Supplemental Rent adjustment clause in future periods is accounted for as an embedded derivative. Derivatives, including embedded derivatives, are recognized at fair value with changes in fair value recorded through net income.

As at December 31, 2009, OPG reported a payable related to the embedded derivative of $118 million. As at March 31, 2010, OPG revalued this embedded derivative and reported a payable of $213 million. The increase in the payable of $95 million was primarily due to reductions to expected future electricity prices compared to the forecast of future prices at the end of 2009. The decrease in the expected forecast of future prices was primarily due to a reduction to short-term and long-term gas prices expressed in U.S. dollars, the strengthening of the Canadian dollar compared to the U.S. dollar, and changed bidding behaviour of other market participants.

The change in fair value of the derivative was recorded as a reduction to Bruce lease revenue. The decrease in Bruce lease revenue was fully offset by the Bruce Lease Net Revenues Variance regulatory asset. As such, there is no net income impact.

3D. Ernst & Young 2010 First Quarter Review Report for 31 March 2010

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The Audit /Risk Committee of the Board of Directors
Ontario Power Generation Inc.

10 May 2010

Dear Members of the Audit / Risk Committee:

We are pleased to present the status of our review of Ontario Power Generation Inc.'s 2010 first quarter financial statements.

This Report to the Audit / Risk Committee summarizes the scope of our review and the status of our final procedures, which will be completed prior to the Company's filing of its interim financial statements. The document also contains the Audit Committee communications required by our professional standards, as well as significant current accounting developments and issues that could or will affect Ontario Power Generation Inc.

Our review is performed in accordance with standards established by the Canadian Institute of Chartered Accountants. A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards. The objective of a review of interim financial information is to provide the auditor with a basis for communicating whether the auditor is aware of any material modifications that should be made to the interim financial information for it to conform with generally accepted accounting principles.

This report is intended solely for the information and use of the Audit / Risk Committee, Board of Directors and management in their review of the interim financial statements, and is not intended to be and should not be used by anyone other than these specified parties. We disclaim any responsibility to any third party who may rely on it. Further, this report is a by-product of our review of the 2010 first quarter financial statements and indicates matters identified during the course of our review. Our review did not necessarily identify all matters that may be of interest to the Audit / Risk Committee in fulfilling its responsibilities.

We appreciate this opportunity to meet with you.

Sincerely,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

Areas of focus and changes in accounting policies, judgments & estimates

Area of focus	Change in policy, judgments and estimates	Findings and Observations
Bruce Lease Embedded Derivative	Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/ MWh In accordance with CICA 3855, *Financial Instruments, Recognition and Measurement*, the conditional reduction to the supplemental rent is considered an embedded derivative that needs to be bifurcated from the lease agreement.	The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index, and a discount rate. As at 31 March 2010, the value of the embedded derivative recorded is $213 million. The amount recorded has been offset against the Bruce revenue variance account, thus there is no impact on net income. EY has reviewed the valuation model developed by OPG's Energy Markets group and we believe the fair value amount recorded at 31 March 2010 is plausible.

3E. Ernst & Young 2010 Second Quarter Review Report for 30 June 2010

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The Audit and Finance Committee of the Board of Directors
Ontario Power Generation Inc.

6 August 2010

Dear Members of the Audit and Finance Committee:

We are pleased to present the status of our review of Ontario Power Generation Inc.'s 2010 second quarter financial statements.

This Report to the Audit and Finance Committee summarizes the scope of our review and the status of our final procedures, which will be completed prior to the Company's filing of its interim financial statements. The document also contains the Audit Committee communications required by our professional standards, as well as significant current accounting developments and issues that could or will affect Ontario Power Generation Inc.

Our review is performed in accordance with standards established by the Canadian Institute of Chartered Accountants. A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards. The objective of a review of interim financial information is to provide the auditor with a basis for communicating whether the auditor is aware of any material modifications that should be made to the interim financial information for it to conform with generally accepted accounting principles.

This report is intended solely for the information and use of the Audit and Finance Committee, Board of Directors and management in their review of the interim financial statements, and is not intended to be and should not be used by anyone other than these specified parties. We disclaim any responsibility to any third party who may rely on it. Further, this report is a by-product of our review of the 2010 second quarter financial statements and indicates matters identified during the course of our review. Our review did not necessarily identify all matters that may be of interest to the Audit and Finance Committee in fulfilling its responsibilities.

We appreciate this opportunity to meet with you.

Sincerely,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

Areas of focus and changes in accounting policies, judgments & estimates (cont'd)

Area of Focus	Changes in policy, judgments and estimates	Findings and Observations
Bruce Lease Embedded Derivative	Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/ MWh. In accordance with CICA 3855, *Financial Instruments, Recognition and Measurement*, the conditional reduction to the supplemental rent is considered an embedded derivative that needs to be bifurcated from the lease agreement.	The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index, and a discount rate. As at 30 June 2010, the value of the embedded derivative recorded is $156 million as compared to $213 million recorded at 31 March 2010 ($118 million, December 2009). The amount recorded has been offset against the Bruce revenue variance account, thus there is no impact on net income. EY has reviewed the valuation model developed by OPG's Energy Markets group and we believe the fair value amount recorded at 30 June 2010 is plausible.

3F. Ernst & Young 2010 Third Quarter Review Report for 30 September 2010

ERNST & YOUNG

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The Audit and Finance Committee of the Board of Directors
Ontario Power Generation Inc.

8 November 2010

Dear Members of the Audit and Finance Committee:

We are pleased to present the status of our review of Ontario Power Generation Inc.'s 2010 third quarter financial statements.

This Report to the Audit and Finance Committee summarizes the scope of our review and the status of our final procedures, which will be completed prior to the Company's filing of its interim financial statements. The document also contains the Audit Committee communications required by our professional standards, as well as significant current accounting developments and issues that could or will affect Ontario Power Generation Inc.

Our review is performed in accordance with standards established by the Canadian Institute of Chartered Accountants. A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards. The objective of a review of interim financial information is to provide the auditor with a basis for communicating whether the auditor is aware of any material modifications that should be made to the interim financial information for it to conform with generally accepted accounting principles.

This report is intended solely for the information and use of the Audit and Finance Committee, Board of Directors and management in their review of the interim financial statements, and is not intended to be and should not be used by anyone other than these specified parties. We disclaim any responsibility to any third party who may rely on it. Further, this report is a by-product of our review of the 2010 third quarter financial statements and indicates matters identified during the course of our review. Our review did not necessarily identify all matters that may be of interest to the Audit and Finance Committee in fulfilling its responsibilities.

We appreciate this opportunity to meet with you.

Sincerely,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

Areas of focus and changes in accounting policies, judgments & estimates (cont'd)

Area of Focus	Changes in policy, judgments and estimates	Findings and Observations
Bruce Lease Embedded Derivative	Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/ MWh. In accordance with CICA 3855, *Financial Instruments, Recognition and Measurement*, the conditional reduction to the supplemental rent is considered an embedded derivative that needs to be bifurcated from the lease agreement.	The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index and a discount rate. As at 30 September 2010, the value of the embedded derivative recorded is $165 million as compared to $156 million recorded at 30 June 2010 ($213 million, 31 March 2010 and $118 million, December 2009). The amount recorded has been offset against the Bruce Lease Net Revenues Variance Account, thus there is no impact on net income. EY has reviewed the valuation model developed by OPG's Energy Markets group and we believe the fair value amount recorded at 30 September 2010 is plausible.

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The Audit and Finance Committee of the Board of Directors
Ontario Power Generation Inc.

22 February 2011

Dear Members of the Audit and Finance Committee,

We are pleased to present the results of our audit of the consolidated financial statements of Ontario Power Generation Inc. This report also includes the status of our audit, which we anticipate will be completed on or about 4 March 2011.

Our audit was designed to express an opinion on the 2010 consolidated financial statements. We continue to receive the full support and assistance of Ontario Power Generation Inc.'s personnel in conducting our audit. Open and candid dialogue with you, as an Audit and Finance Committee member, is a critical step in the audit process, and in the overall corporate governance process and we appreciate this opportunity to share the insights from our audit with you.

At Ernst & Young, we continually evaluate the quality of our professionals' work in order to deliver remarkable client service. We strive to provide you with audit services of the highest quality that will meet or exceed your expectations, and we encourage you to participate in our Assessment of Service Quality (ASQ) process to provide your input on our performance. The ASQ process is a critical tool that enables us to monitor and improve the quality of our audit services to Ontario Power Generation Inc.

This report is intended solely for the information and use of the Audit and Finance Committee, Board of Directors and management. It is not intended to be, and should not be, used by anyone other than these specified parties.

We look forward to meeting with you to discuss the contents of this report and answer any questions you may have about these or any other audit-related matters.

Sincerely,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

2010 audit results

Critical policies, estimates and areas of audit emphasis

Area of emphasis / critical accounting policy	Ernst & Young comments on quality and application of accounting policy, significant estimates, financial statement disclosures and related matters
Bruce Lease Embedded Derivative Accounting policy: The Company values certain investments and financial instruments (available for sale, trading and other assets and liabilities that the Company may elect to carry at fair value) at fair value, measured in accordance with CICA 3855. For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the balance sheet date. Critical policy? Yes.	Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/MWh. This clause was first triggered in 2009. In accordance with CICA 3855, the adjustment to the supplemental rent is considered an embedded derivative that needs to be bifurcated from the lease agreement and fair valued. The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index, and a discount rate. As at 31 December 2010, the value of the embedded derivative recorded is $163 million. We have reviewed the valuation model developed by OPG's Energy Markets group, and concur with the fair value amount recorded of $163 million. The amount recorded has been offset against the Bruce net revenue variance account, thus there is no impact on net income

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The Audit and Finance Committee of the Board of Directors
Ontario Power Generation Inc.

21 February 2012

Dear Members of the Audit and Finance Committee,

We are pleased to present the results of our audit of the financial statements of Ontario Power Generation Inc. This report also includes the status of our audit, which we anticipate will be completed on or about March 2, 2012.

Our audit was designed to express an opinion on the 2011 consolidated financial statements. We continue to receive the full support and assistance of Ontario Power Generation Inc.'s personnel in conducting our audit. Open and candid dialogue with you, as an audit committee member, is a critical step in the audit process, and in the overall corporate governance process and we appreciate this opportunity to share the insights from our audit with you.

This report is intended solely for the information and use of the Audit Committee, Board of Directors and management. It is not intended to be, and should not be, used by anyone other than these specified parties.

We look forward to meeting with you to discuss the contents of this report and answer any questions you may have about these or any other audit-related matters.

Very truly yours,

Ernst + Young LLP

Chartered Accountants
Licensed Public Accountants

Critical policies, estimates and areas of audit emphasis

Area of emphasis; risk considerations	Critical policy (1)	Ernst & Young comments on quality of accounting policy and application
Financial instruments – Bruce lease embedded derivative		
The Company values certain investments and financial instruments (available for sale, trading and other assets and liabilities that the Company may elect to carry at fair value) at fair value, measured in accordance with CICA 3855. For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the balance sheet date.	✓	Included in the Bruce Lease Agreement is a provision that allows for reduced supplemental rent payments if the annual HOEP arithmetic average cost of power falls below $30/MWh. This clause was first triggered in 2009. In accordance with CICA 3855, the adjustment to the supplemental rent is considered an embedded derivative that needs to be bifurcated from the lease agreement and fair valued. The value of the embedded derivative is determined based on a number of factors including forward price curves for future years, the volatility of the HOEP price, forecasted consumer price index, and a discount rate. As at 31 December 2011, the value of the embedded derivative liability recorded is $186 million. We have reviewed the valuation model developed by OPG's Energy Markets group, and concur with the fair value amount recognized. The amount recorded has been offset against the Bruce Lease Net Revenues variance regulatory account, thus there is no impact on net income.

(1) Represents critical accounting policies included in Note 3 to the Company's financial statements

SEC Interrogatory #06

Ref: H2/1/2

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, including all calculations, of all impacts on the balance in the Bruce Lease Net Revenues Variance Account resulting from changes in discount or interest rates since EB-2010-0008.

Response

As directed by the OEB, OPG calculates all Bruce revenue and cost items in accordance with generally accepted accounting principles ("GAAP") for unregulated entities. To the extent the values of Bruce revenue or cost items are affected by the use or impact of discount or interest rates and result in debit or credit entries into the variance account for 2011 or 2012, the derivation/application of such rates and their impacts is in accordance with CGAAP.

OPG cannot identify or quantify all possible impacts of changes in interest rate levels since EB-2010-0008 because interest rates are a fundamental factor in the macroeconomic environment. Interest rate changes do not occur in isolation. Rather, when interest rates change, many other factors in the economy that could affect the balances in the Bruce Lease Net Revenues Variance Account typically change as well. OPG has no basis on which to assess these multiple and interrelated economic impacts. For these reasons, OPG views the requested calculations as having limited value to the OEB or intervenors.

Nevertheless, where possible and subject to stated assumptions, OPG provides estimated impacts on the year-end 2012 projected balance of the account presented in the pre-filed evidence of changes in discount or interest rates since EB-2010-0008.[1]

As discussed below, OPG has identified the following revenue and cost items captured by the Bruce Lease Net Revenues Variance Account that are directly impacted by changes in discount or interest rates:

- Changes in the fair value of the derivative embedded in the Bruce Lease agreement, which impact Supplemental Rent Revenue
- Items impacted by the nuclear asset retirement obligation ("ARO"):
    - Depreciation Expense
    - Used Fuel Storage and Disposal Variable Expenses
    - Low and Intermediate Level ("L&IL") Waste Management Variable Expenses

[1] Secondary impacts on interest applied on the outstanding balance of the account have not been included.

- o Accretion Expense
- Earnings on Segregated Funds
- Interest Expense
- Tax impacts associated with the above items

<u>Supplemental Rent Revenue – Embedded Derivative</u>
As explained in L-1-1 Staff-10 c, the fair value of the embedded derivative is calculated on a present value basis. Holding all else constant and using the valuation model described in L-1-1 SEC-5, OPG has re-calculated the derivative liability value at Q2 2012 and the projected value of increase in the liability due to the Bruce B life extension originally provided at pages 2 and 3, respectively, of Attachment 1 to L-1-1 Staff-10, assuming a discount rate of 3.52 per cent. This rate was used to determine the fair value the derivative as at December 31, 2010. These hypothetical valuations are provided at pages 1 and 2 of Attachment 1 to this response. The hypothetical values, as well as those provided in L-1-1 Staff-10 and resulting differences are shown in Chart 1 below.[2] The year-end projected balance of the Bruce Lease Net Revenues Variance Account would be lower by $19.9M, which is the total amount of these differences.

OPG notes that, as explained in L-1-1 Staff-10 and L-1-1 SEC-5, the Consumer Price Index ("CPI") value is also an input into the calculation of the derivative. Generally speaking, higher interest/discount rate are expected to be correlated with higher CPI values. In turn, higher CPI values would increase the value of the derivative liability. Therefore, in reality, one would expect the net impact of a higher interest rate environment to result in higher derivative liability values than the hypothetical values provided below. However, OPG has no basis for speculating on what such hypothetical CPI values might be in an alternate macroeconomic environment and, therefore, is unable to quantify this impact.

Chart 1
Impact of Discount Rates on Embedded Derivative*

Item ($M)	Actual/ Projected Value	Hypothetical Value	Difference
Derivative Value at Q2 2012	228.8	225.3	3.5
Projected Increase in Derivative Value at Year End 2012 Due to Bruce B Life Extension	306.1	289.7	16.4
Hypothetical Reduction in Bruce Lease Net Revenues Variance Account			**19.9**

* Numbers may not calculate due to rounding

<u>Nuclear Asset Retirement Obligation Impacts</u>
As discussed in L-7-1 SEC-12, the year-end 2011 ARO adjustment was recognized using the credit-adjusted risk-free rate of 3.43 per cent, as required by CGAAP and USGAAP (noted in

[2] It is not necessary to revalue the year-end 2011 derivative value provided at page 1 of Attachment 1 to L-1-1-Staff-10 because impacts on that value are already captured by the revaluation of the Q2 2012 life-to-date value.

L-2-1 Staff-20 a). The previous ARO adjustment was recognized as at January 1, 2010 at the then-determined credit-adjusted risk-free rate of 4.8 per cent. For the purposes of calculating the impact of changes in discount rates on the ARO since EB-2010-0008, OPG has recalculated the year-end 2011 ARO adjustment using the January 1, 2010 rate of 4.8 per cent, holding all else constant. The recalculation was performed in the same manner as described in L-1-1 Staff-04 a.

The resulting hypothetical year-end 2011 ARO and asset retirement cost ("ARC") adjustment, by program and station in the same format as the top chart (lines 1 to 7) of Ex. H2-1-1, Table 3, is provided in Table 2 of Attachment 2 to this interrogatory. The calculation of this adjustment, in the same format as provided in L-1-7 SEC-15, is provided in Attachment 4 to this interrogatory. As shown in col. (g) of Attachment 2, Table 2, the portion of the hypothetical adjustment attributable to the Bruce facilities has been calculated at $365.1M. Assuming this adjustment, Table 1 in Attachment 2 recasts the details of the actual 2011 and projected 2012 projected ARO and ARC balances in the same format as Ex. H2-1-1, Table 2.

As noted above, inflation rates and interest rates generally move in tandem and, as such, higher interest rates likely would also have been accompanied by higher escalation rates assumed as part of the approved 2012 ONFA Reference Plan lifecycle liability and therefore reflected in the ARO adjustment. As such, the impact of the hypothetical interest rate of 4.8 per cent on the adjustment (and resulting expense impacts) would likely have been at least partially offset. However, as also discussed above, OPG has no basis for speculating on such hypothetical inflation or escalation rates in an alternate macroeconomic environment and, therefore, is unable to quantify this impact.

A different year-end 2011 ARO adjustment ($365.1M instead of $495.1M in Ex. H2-1-1, Table 3, col. (g)) and a different accretion rate (4.8 per cent instead of 3.43 per cent) would affect depreciation expense, variable expenses for used fuel storage and disposal and L&IL waste management, and accretion expense for 2012.[3] These items are reflected in Table 1 of Attachment 2. The differences between these hypothetical amounts and the amounts provided in Ex. H2-1-1, Table 2 are summarized in Chart 2 below. The year-end projected balance of the Bruce Lease Net Revenues Variance Account would be lower by $26.8M, which is the total amount of these differences.

[3] The impact of discount rates on variable expenses is discussed at Ex. H2-1-1, page 4, lines 4-10 and in L-1-7 SEC-12. The derivation of accretion expense is explained at Ex. H2-1-2, page 8, line 23 to page 9, line 8.

Chart 2
Impact of Discount Rates on 2012 ARO Items

Item ($M)	Projected 2012 Value**	Hypothetical 2012 Value***	Difference
Depreciation Expense	69.1	56.8	12.3
Used Fuel Storage and Disposal Variable Expenses	43.5	29.0	14.5
Low and Intermediate Level Waste Management Variable Expenses	1.8	1.4	0.4
Accretion Expense	328.5	328.9	(0.4)
Hypothetical Net Reduction in Bruce Lease Net Revenues Variance Account			**26.8**

* Numbers may not calculate due to rounding
** Projected 2012 values from Ex. H2-1-1, Table 2, col. (c): line 23 for depreciation expense, line 4 for used fuel variable expenses, line 5 for L&IL waste management variable expenses, line 6 for accretion expense
***Hypothetical 2012 values from L-1-7 SEC-06, Att. 2, Table 1, col. (b): line 12 for depreciation expense, line 2 for used fuel variable expenses, line 3 for L&IL waste management variable expenses, line 4 for accretion expense

Charts 1 and 2, respectively, in Attachment 3 to this response provide the calculation of the above hypothetical values for used fuel variable expenses and depreciation expense in the same format as Charts 1 and 3, respectively, do in L-1-7 SEC-02 for the projected amounts from Ex. H2-1-1, Table 2 in the pre-filed evidence. The impacts on the L&IL waste management variable expenses and accretion expenses at $0.4M and ($0.4M), respectively are small and offsetting.

<u>Earnings on Segregated Funds</u>
As with any investment portfolio, the earnings on the nuclear segregated funds, and therefore the portion attributable to the Bruce facilities, are impacted by the level of interest rates. However, OPG has no basis to speculate on the performance of capital markets had interest rates remained at the same levels as at the time of the EB-2010-0008 application. Therefore, OPG is unable to quantify the impact of changes in interest rates in relation to segregated fund earnings.

The projected 2012 contributions to the segregated funds under the ONFA are considered not to be impacted because, as noted in response to L-2-1 Staff-18, the discount rate determined in accordance with the provisions of the ONFA (i.e., 5.15 per cent) is the same for both the approved 2012 ONFA Reference Plan and the previous approved reference plan in effect at the time of EB-2010-0008.

<u>Interest Expense</u>
As explained in Ex. H2-1-2, page 11, lines 18-24, a portion of OPG's corporate-wide accounting interest expense is allocated to the Bruce facilities for the purposes of

determining Bruce Lease net revenues. OPG estimates that the impact on interest expense of changes in interest rates since EB-2010-0008 is less than $0.5M. The impact is small because OPG's corporate-wide long-term debt is at fixed rates and project-specific interest is attributed to the appropriate business units. Thus only a small portion of OPG's corporate-wide interest expense remains to be allocated to the Bruce facilities.

<u>Income Tax Impacts</u>
Excluding the negligible impact on current income taxes that would arise due to the hypothetically lower interest expense, all of the quantifiable impacts above (reductions in the fair value of the derivative and ARO-related costs) would affect future income taxes. The difference in future income taxes is estimated by multiplying these reductions by 25 per cent, the tax rate in effect for 2012 (the year to which most of the above impacts pertain). The result would be an increase to future income taxes of $11.7M ($19.9M + $26.8M) x 25 per cent), which would increase the 2012 balance in the Bruce Lease Net Revenues Variance Account.

<u>Total Impact</u>
The net total of the above quantified impacts on the projected 2012 balance of the Bruce Lease Net Revenues Variance Account would be a hypothetical decrease in the balance of $35.0M.

Hypothetical Q2 2012 Valuation

(using year-end 2010 discount rate)

Valuation Date	**Fri 29-Jun-2012**			**Bruce Embedded Derivative Valuation**	
Discount Rate (Year-end 2010)	**3.52%**				
		2012	**2013**	**2014**	**Total**
Estimated CPI		2.18%	2.50%	2.10%	
Full Supplemental Rent		125,609,563	128,749,802	131,453,548	385,812,913
Reduced Supplemental Rent		48,000,000	48,000,000	48,000,000	144,000,000
Full Rent Rebate		77,609,563	80,749,802	83,453,548	241,812,913
PV of Full Rent Rebate		76,264,250	76,651,908	76,524,772	229,440,931
Exercise Probability		100.00%	98.92%	95.69%	
PV of Expected Rebate		**76,264,247**	**75,822,039**	**73,230,011**	**225,316,298**
Average HOEP to Date		**19.62**			
Daily Volatility		1.17%	1.09%	1.09%	
Expected Annual Average HOEP		**20.05**	**18.84**	**20.31**	

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

Hypothetical Valuation of Life Extension

(using year-end 2010 discount rate)

Valuation Date	**Fri 29-Jun-2012**			**Bruce Embedded Derivative Valuation**		
Discount Rate (Year-end 2010)	3.52%			**— Life Extension —**		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Estimated CPI	2.10%	2.10%	2.10%	2.10%	2.10%	
Full Supplemental Rent	134,214,072	137,032,568	139,910,252	142,848,367	145,848,183	699,853,442
Reduced Supplemental Rent	48,000,000	48,000,000	48,000,000	48,000,000	48,000,000	240,000,000
Full Rent Rebate	86,214,072	89,032,568	91,910,252	94,848,367	97,848,183	459,853,442
PV of Full Rent Rebate	76,367,951	76,182,920	75,971,099	75,733,852	75,472,492	379,728,314
Exercise Probability	89.24%	81.71%	77.42%	71.32%	61.64%	
PV of Expected Rebate	**68,153,948**	**62,250,390**	**58,815,977**	**54,011,551**	**46,517,823**	**289,749,688**
Average HOEP to Date						
Daily Volatility	1.09%	1.09%	1.09%	1.09%	1.09%	
Expected Annual Average HOEP	**22.82**	**24.77**	**25.71**	**26.94**	**28.75**	

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

Table 1
Bruce Facilities - Hypothetical Asset Retirement Obligation and Asset Retirement Costs ($M)
Years Ending December 31, 2011 and 2012

Line No.	Description	Note	2011 Actual[1]	2012 Projection[1]
			(a)	(b)
	ASSET RETIREMENT OBLIGATION (ARO)			
1	**Opening Balance**		5,357.0	5,977.7
2	**Used Fuel Storage and Disposal Variable Expenses**	2, 3	27.0	29.0
3	**Low & Intermediate Level Waste Management Variable Expenses**	2	1.0	1.4
4	**Accretion Expense**	2	296.6	328.9
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**	2	(68.1)	(120.4)
6	**Consolidation and Other Adjustments**		(1.0)	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)		5,612.6	6,216.6
8	**Hypothetical Current Approved ONFA Reference Plan Adjustment**	4, 5	365.1	563.0
9	**Closing Balance** (line 7 + line 8)		5,977.7	6,779.5
10	**Average Asset Retirement Obligation** ((line 1 + line 9)/2)		5,484.8	6,097.1
	ASSET RETIREMENT COSTS (ARC)			
11	**Opening Balance**		817.6	1,158.8
12	**Depreciation Expense**	2, 3	(23.9)	(56.8)
13	**Closing Balance Before Year-End Adjustments** (line 11 + line 12)		793.7	1,102.0
14	**Hypothetical Current Approved ONFA Reference Plan Adjustment**	4, 5	365.1	563.0
15	**Closing Balance** (line 13 + line 14)		1,158.8	1,664.9
16	**Average Asset Retirement Costs** ((line 11 + line 13)/2))		805.7	1,130.4

Notes:

1 Lines 1-6 and lines 11-12 in col. (a) from Ex. H2-1-1, Table 2, col. (b). Lines 5-6 in col. (b) from Ex. H2-1-1, Table 2 col. (c).

2 Col. (b) amounts at lines 2, 3, 4 and 12 are hypothetical expense amounts recalculated assuming a hypothetical discount rate of 4.8% for purposes of determining the year-end 2011 ARO/ARC adjustment.

3 Amounts determined in Attachment 3, Charts 1 and 2.

4 Col. (a) reflects hypothetical adjustment on December 31, 2011 calculated using a discount rate of 4.8% associated with the current approved ONFA Reference Plan effective January 1, 2012 (from L-1-7 SEC-06, Att 2, Table 2, col. (g), line 7 for ARO and line 16 for ARC).

5 Col. (b) reflects the same values for the projected December 31, 2012 ARO/ARC adjustment as the pre-filed evidence at Ex. H2-1-1, Table 2, lines 10 and 25, col. (c). These values have **not** been adjusted to reflect the hypothetical discount rate of 4.8%, as they do not impact amounts recorded in the Bruce Lease Net Revenues Variance Account for 2012.

Table 2

Hypothetical Impact of Current Approved ONFA Reference Plan - Assignment of ARO and ARC Adjustments to Nuclear Stations ($M)[1]

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)
	2011:								
1	**Decommissioning Program**	(53.2)	(148.0)	(129.4)	(330.6)	(174.1)	(179.8)	(353.9)	(684.5)
2	**Low and Intermediate Level Waste Storage Program**	93.3	59.8	44.3	197.4	136.2	19.8	156.0	353.4
3	**Low and Intermediate Level Waste Disposal Program**	199.9	158.1	22.0	380.1	255.1	33.3	288.4	668.5
4	**Used Fuel Disposal Program**	(8.1)	(28.2)	(63.2)	(99.5)	5.5	(21.4)	(15.9)	(115.4)
5	**Used Fuel Storage Program**	130.2	160.9	154.1	445.2	56.7	233.8	290.4	735.7
6	**ARO Adjustment Assignment to Station Level**	362.2	202.7	27.8	592.6	279.3	85.7	365.1	957.7
7	**Asset Retirement Cost Adjustment**	362.2	202.7	27.8	592.6	279.3	85.7	365.1	957.7

Notes:

1 Amounts were calculated assuming a hypothetical discount rate of 4.8% as of December 31, 2011 instead of the actual discount rate of 3.43%. The details of the calculation of the amounts are provided in Ex. L-1-7 SEC-06, Attachment 4.

ATTACHMENT 3

Chart 1
2012 Used Fuel Variable Expenses for Bruce Facilities Using 4.8% Discount Rate[1]

Facility	Used Fuel Volume[2] (bundles) (a)	UFD Variable Cost Rate ($/bundle) (b)	UFS Variable Cost Rate ($/bundle) (c)	UFD Variable Expenses ($k) (d)=(a)x(b)	UFS Variable Expenses ($k) (e)=(a)x(c)	Total Used Fuel Variable Expense ($k) (f)=(d)+(e)
Bruce A	7,557	617	34	4,659	256	8,056
Bruce B	22,522	617	452	13,885	10,174	35,495
Total	30,079	N/A	N/A	18,544	10,429	28,974

[1] Numbers may not calculate due to rounding
[2] Same volume as in Chart 1 of L-1-7 SEC-02

Chart 2
2012 ARC Depreciation Expense for Bruce Facilities Using 4.8% Discount Rate[1]

	Bruce A	Bruce B	Total
Net book value of ARC at Jan 1, 2012 ($M) *(1)*	1,094.3	64.5	1,158.8[2]
Remaining service life at Jan 1, 2012 (yrs)[3] *(2)*	31	3	N/A
2012 Depreciation Expense ($M) *(3)=(1)/(2)*	35.3	21.5	56.8

[1] Numbers may not calculate due to rounding
[2] Total opening ARC net book value as per Attachment 2, Table 1, line 11.
[3] Based on average station end-of-life dates in effect as at December 31, 2011 of: December 31, 2042 for Bruce A, December 31, 2014 for Bruce B (from page 3 of Att. 2 to L-2-1 Staff-19 and L-2-1 SEC-10)

ATTACHMENT 4

This attachment provides the derivation of a hypothetical 2011 year-end nuclear ARO adjustment assuming a discount rate of 4.8 per cent, as presented in L-1-7 SEC-06, Attachment 2, Table 2. The derivation is presented in the same four steps as the calculation of the actual 2011 year-end ARO adjustment (using a discount rate of 3.43 per cent) in L-1-7 SEC-15. With the exception of the different discount rate, all other inputs, assumptions and methodology are the same as that reflected in L-1-7 SEC-15 and explained in L-1-1 Staff-04.

A) Developing ARO cost estimates for each of the five nuclear waste management and decommissioning programs

The cost estimates (cash flows) for the ARO are developed based on the cost estimates from the 2012 ONFA Reference Plan.

The following Chart A provides the actual 2011 ARO cost estimates (cash flows from 2012 onward) in 2010 constant dollars (“2010 C$”).

Chart A

A. 2011 ARO 2010 C$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	1,598	1,636	2,106	5,340	1,731	1,484	3,215	8,555
Low and Intermediate Level Waste Storage Program	260	206	205	671	382	62	444	1,114
Low and Intermediate Level Waste Disposal Program	443	380	355	1,178	668	108	776	1,954
Used Fuel Disposal Program	1,693	1,689	5,728	9,109	4,597	2,939	7,536	16,646
Used Fuel Storage Program	392	339	629	1,359	497	477	974	2,333
Total ARO	**4,386**	**4,248**	**9,023**	**17,657**	**7,875**	**5,070**	**12,945**	**30,602**

*Numbers may not add due to rounding.

B) Converting the constant dollar ARO cost estimates (cash flows) into the escalated dollar ARO cost estimates (cash flows)

Since the cost estimates (cash flows) are originally developed in 2010 C$, a single long-term escalation rate for each of the cost elements (i.e., labour, materials and other) is used to escalate the constant dollar estimates. The resulting escalated cash flows form the bases for the updated ARO.

The escalation rates are based on long-term projections for Ontario from the Policy and Economic Analysis Program published by the University of Toronto. The escalation rates are 3.7 per cent for labour costs, 2.0 per cent for material costs and 1.9 per cent for other costs and are applied to all programs in Chart B.

The following Chart B provides the 2011 ARO cost estimates (cash flows) in escalated dollars (“ESC$”).

Chart B

B. 2011 ARO ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	5,330	4,548	18,380	28,257	11,305	4,820	16,126	44,383
Low and Intermediate Level Waste Storage Program	483	386	381	1,250	711	115	827	2,076
Low and Intermediate Level Waste Disposal Program	800	689	643	2,131	1,208	195	1,403	3,534
Used Fuel Disposal Program	15,735	15,668	53,913	85,316	43,648	27,480	71,128	156,444
Used Fuel Storage Program	658	554	1,629	2,841	1,123	927	2,050	4,891
Total ARO	**23,006**	**21,843**	**74,946**	**119,795**	**57,996**	**33,537**	**91,533**	**211,328**

*Numbers may not add due to rounding.

C) Calculating the ARO adjustment in escalated dollars

The adjustment in ESC$ is the incremental cash flow representing the annual differences between the updated ARO escalated cost estimates (from Chart B above) and the escalated cash flows underlying the unadjusted value of the ARO as of year-end in ESC$.

The following Chart C.1 provides the ESC$ cost estimates (cash flows) underlying the 2011 year-end actual value of the ARO prior to adjustment.

Chart C.1

C.1 2011 Unadjusted ARO Value ESC$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	5,647	5,105	21,174	31,926	9,871	4,689	14,560	46,486
Low and Intermediate Level Waste Storage Program	160	156	189	505	244	45	289	793
Low and Intermediate Level Waste Disposal Program	246	237	457	940	455	87	542	1,482
Used Fuel Disposal Program	16,198	16,419	54,650	87,268	42,691	27,740	70,431	157,699
Used Fuel Storage Program	555	466	1,155	2,176	913	507	1,419	3,596
Total ARO	**22,807**	**22,383**	**77,625**	**122,815**	**54,174**	**33,067**	**87,241**	**210,056**

*Numbers may not add due to rounding.

The following Chart C.2 provides the cash flows for the actual 2011 year-end ARO adjustment in ESC$, as derived by subtracting the corresponding values in Chart C.1 from those in Chart B.

Chart C.2

C.2 2011 ARO Adjustment ESC$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	(317)	(558)	(2,794)	(3,668)	1,434	132	1,566	(2,103)
Low and Intermediate Level Waste Storage Program	323	230	192	745	467	71	538	1,283
Low and Intermediate Level Waste Disposal Program	553	452	185	1,190	753	108	861	2,051
Used Fuel Disposal Program	(463)	(752)	(737)	(1,952)	957	(260)	697	(1,255)
Used Fuel Storage Program	103	88	474	664	210	421	631	1,295
Total Adjustment	**200**	**(541)**	**(2,679)**	**(3,020)**	**3,822**	**471**	**4,292**	**1,272**

*Numbers may not add due to rounding.

D) Calculating the ARO adjustment in present value terms

The adjustment cost flows are discounted to present value dollars ("PV$") by applying a hypothetical discount rate of 4.8 per cent.

The following Chart D provides the hypothetical 2011 year-end ARO adjustment (from Chart C.2) as converted into PV$ using the hypothetical discount rate of 4.8 per cent. The values in this chart are also found in L-1-7 SEC-06, Attachment 2, Table 2.

Chart D

D 2011 ARO Adjustment PV$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	(53)	(148)	(129)	(331)	(174)	(180)	(354)	(685)
Low and Intermediate Level Waste Storage Program	93	60	44	197	136	20	156	353
Low and Intermediate Level Waste Disposal Program	200	158	22	380	255	33	288	669
Used Fuel Disposal Program	(8)	(28)	(63)	(100)	6	(21)	(16)	(115)
Used Fuel Storage Program	130	161	154	445	57	234	290	736
Total Adjustment	**362**	**203**	**28**	**593**	**279**	**86**	**365**	**958**

*Numbers may not add due to rounding.

SEC Interrogatory #07

Ref: H2/1/2, p. 13

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

Interrogatory

Please confirm that the $96.9 million reduction in future tax expense in unaffected by the period over which any a balance in the variance account is recovered from ratepayers.

Response

OPG confirms that the variance in future income taxes is a component of projected principal entries (i.e., excluding interest and account balance amortization entries) into the Bruce Lease Net Revenues Variance Account for 2012. As with other principal entries into the account, this amount is not affected by the period over which the accumulated account balance is recovered.

SEC Interrogatory #08

Ref: L/1/1, Staff 9, p. 3

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

Interrogatory

Please advise when the "actual amount of the rent rebate" will be calculated.

Response

The amount of the 2012 supplemental rent rebate is expected to be finalized by February 2013.

SEC Interrogatory #09

Ref: L/1/1, Staff 10, Attach. 1

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

Interrogatory

Please advise the source and rationale for the use of the 2.60% and 2.46% discount rates. Please provide a sensitivity analysis to changes in these rates.

Response

The cited discount rates have been used in calculating and recording the fair value of the derivative liability at December 31, 2011 and June 30, 2012 as reported in consolidated financial statements, including the audited financial statements for 2011. The discount rates cited above are based on OPG's 5-year bond yields based on spread information obtained from financial institutions at the time of calculation. OPG is required to reflect its borrowing rate in the valuation of a financial liability in accordance with generally accepted accounting standards. The 5-year term is used as it approximates the period over which the derivative is valued (i.e., the average remaining service life of the Bruce B station, for accounting purposes). The discount rates are determined using a consistent approach. OPG's external auditor, Ernst & Young, independently reviews the valuations of the derivative, including significant inputs such as the discount rate as noted in Ex. H2-1-2, page 4, lines 21-24.

A sensitivity analysis presented in the table below has been prepared holding constant all inputs to the valuation of the derivative constant except the discount rate. Based on the analysis, the impacts of a relatively substantial change (+ or - 1 %) in the discount rates cited above, expressed as percentage of the derivative liability values presented in Ex. L-1-1 Staff-10, Attachment 1, indicate that the value of the derivative is not substantially sensitive to a discount rate changes.

Valuation	Discount Rate Minus 1%	Discount Rate Plus 1%
Change in Derivative Value at Year End 2011[1]	+1.9%	-1.9%
Change in Derivative Value at Q2 2012[2]	+1.5%	-1.4%
Change in Projected Increase in Derivative Value at Year End 2012 Due to Bruce B Life Extension[3]	+5.4%	-5.1%

[1] Actual value calculated at a discount rate of 2.60% as per L-1-1 Staff-10, Attachment 1, page 1
[2] Actual value calculated at a discount rate of 2.46% as per L-1-1 Staff-10, Attachment 1, page 2
[3] Projected value is calculated at a discount rate of 2.46% as per L-1-1 Staff-10, Attachment 1, page 3

SEC Interrogatory #10

Ref: L/2/1, Staff 19, Attach 2, p. 3

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

Interrogatory

Please reconcile the end-of-life dates of 2042 and 2014 with the December 2036 lease expiry assumption in the derivatives calculations.

Response

As noted in Ex. H2-1-2, p. 5 and L-1-1 Staff-08, the partial rebate by OPG to Bruce Power L.P. ("Bruce Power") of supplemental rent payments currently applies only to the Bruce B units. As noted in the table on page 3 of Attachment 2 to Ex. L-2-1 Staff-19, the cited average station end-of-life date of December 31, 2042, in effect prior to December 31, 2012, was for the Bruce A station and, therefore, to date, has not been used in the calculations of the fair value of the derivative embedded in the terms of the Bruce Lease agreement.

As noted in L-1-1 Staff-08, if a Bruce A unit ceases to be subject to the Bruce Power Refurbishment Implementation Agreement and is expected to be operational in the future, the fair value of the derivative will need to be increased during that calendar year determined using the same approach described for the Bruce B units.

Prior to December 31, 2012 the Bruce B station average end-of-life date, for depreciation purposes, of December 31, 2014 was used in order to determine the fair value of the derivative.

The average service life, for depreciation purposes, of the Bruce B station has been extended, effective December 31, 2012 based on the 2012 recommendations of OPG's Depreciation Review Committee (see L-2-2 AMPCO-06). The new end-of-life date of December 31, 2019 is being used to establish the fair value of the derivative starting on December 31, 2012.

As explained in Ex. H2-1-2, section 4.1.1 and L-1-1 Staff-06, the date of December 31, 2036 represents the expected lease term, determined in accordance with requirements for lease accounting under the generally accepted accounting principles for non-regulated businesses. This expected lease term only impacted the calculation of Bruce Lease base rent revenue recognized. The expected lease term is not used in and does not impact the calculation of the fair value of the derivative.

SEC Interrogatory #11

Ref: H1/1/1, Table 9

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

Interrogatory

Please show in detail the calculation of the accretion rate of 5.58%. Please use the same method of calculation, but with more current market rates of interest, to demonstrate the impact of updating the accretion rate.

Response

In accordance with Canadian and USGAAP, as noted in L-2-1 Staff-20, OPG's asset retirement obligation for nuclear waste management and decommissioning of nuclear stations ("Nuclear Asset Retirement Obligation (ARO)" or "Nuclear Liabilities") is impacted by changes in discount (interest) rates when a new tranche representing the present value of an increase in the estimated undiscounted escalated cash flow for the ARO is recognized. The amount of such a tranche is derived using the rate determined at the time of the increase; however, the existing ARO tranches remain at historical rates originally used to measure them.

The weighted average accretion rate of 5.58% established as of January 1, 2010 was discussed in EB-2010-0008, Ex. C2-1-2, p. 6, footnote 4 and p. 10, footnote 5), and was used in setting EB-2010-0008 payment amounts. The detailed calculation of the 5.58% accretion rates is shown in Chart 1 below.

Chart 1
Calculation of Weighted Average Accretion Rate of 5.58%[1]

ARO Tranche	Amount of Liabilities at Jan 1, 2010 ($M)	Weighting	Accretion Rate[2]	Weighted Average Accretion Rate
Tranche prior to December 31, 2006	10,144.9	84.6%	5.75%	4.86%
Tranche recoded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan	1,558.7	13.0%	4.6%	0.60%
Tranche recorded on January 1, 2010 related to the Darlington Refurbishment project	293.0	2.4%	4.8%	0.12%
Total/ Weighted average as at January 1, 2010[3]	11,996.6	100%	N/A	5.58%

[1] Amounts may not add due to rounding
[2] Accretion rates for the tranches are as noted at EB-2010-0008, Ex. G2-2-1, p. 10
[3] Represents OPG's total Nuclear Liabilities excluding consolidation adjustments

For the 2011 year-end nuclear ARO increase, a new tranche was recorded using the rate of 3.43% determined at the time of the increase. The accretion rates applicable to the previously existing tranches were not impacted.

The additional tranche recorded at 2011 year-end results in a small decrease in the weighted average rate to 5.43% as at December 31, 2011, as shown in Chart 2 below.

Chart 2
Calculation of Year-End 2011 Weighted Average Accretion Rate[1]

ARO Tranche	Amount of Liabilities at Dec 31, 2011 ($M)	Weighting	Accretion Rate[2]	Weighted Average Accretion Rate
Tranche prior to December 31, 2006	11,043.4	78.7%	5.75%	4.52%
Tranche recoded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan	1,671.1	11.9%	4.6%	0.55%
Tranche recorded on January 1, 2010 in relation to the decision related to Darlington Refurbishment project	391.3	2.8%	4.8%	0.13%
Tranche recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan	934.3	6.7%	3.43%	0.23%
Total/ Weighted average as at December 31, 2011[3]	14,040.1	100%	N/A	5.43%

[1] Amounts may not add due to rounding
[2] Accretion rates for the first three tranches are as noted at EB-2010-0008, Ex. G2-2-1, p. 10
[3] Represents OPG's total Nuclear Liabilities excluding consolidation adjustments

The December 31, 2011 amounts of the previously existing tranches in Chart 2 are different from those in Chart 1 due to the impact of accretion expense, variable expenses for used fuel storage and disposal and low and intermediate level waste management, and expenditures against the liabilities for the period from January 1, 2010 to December 31, 2011.

SEC Interrogatory #12

Ref: H2/1/1, pp. 2-4

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

Interrogatory

Please explain the different applications of the 5.15% discount rate, the 3.43% discount rate, the 4.8% discount rate, and the 5.58% accretion rate. Please include in the explanations examples of the sensitivities of the calculations in which each is used to changes, up or down, in the particular rate. Please include in your answer the source of the rate, and the statutory, regulatory, or other authority for the use of that rate.

Response

All discount/accretion rates referenced in the question have been established and/or calculated pursuant to specifically defined requirements, as discussed below, and form the basis of resulting amounts, if any, recorded in the applicable variance and deferral accounts. As such, while the requested sensitivities, where available, are discussed below, they are not relevant to this proceeding.

The discount rate of 5.15% was determined in accordance with the Ontario Nuclear Funds Agreement ("ONFA") for the 2012 ONFA Reference Plan (as well as the previous ONFA Reference Plan approved in December 2006), as discussed further in L-2-1-Staff-18. As noted in at Ex. H2-1-1, p. 2, lines 5-8, this rate is applied in calculating the present value of the lifecycle liability established by the reference plan. Generally speaking, a higher discount rate in the ONFA Reference Plan, all else being equal, would tend to reduce the lifecycle liability.

The discount rate of 5.58% is the weighted average accretion rate established as of January 1, 2010 discussed in EB-2010-0008, Ex. C2-1-2, p. 6, footnote 4 and p. 10, footnote 5) and was used in setting EB-2010-0008 payment amounts. The calculation of this rate is detailed in L-1-7 SEC-11.

In accordance with the OEB-established methodology for the recovery of costs associated with the nuclear ARO for OPG's prescribed assets (EB-2010-0008, Ex. C2-1-2, section 3.2.4), the weighted average accretion rate is applied to the lesser of the average unfunded Asset Retirement Obligation ("ARO") for the prescribed nuclear facilities and the average unamortized asset retirement costs for these facilities in order to determine the portion of nuclear rate base that earns the weighted average accretion rate rather than the weighted average cost of capital. All else being equal, a higher rate would increase the return on nuclear rate base included in OPG's nuclear revenue requirement, and vice versa.

An example of illustrative sensitivity can be calculated based on the lesser of the average unfunded ARO and asset retirement costs for 2012 for the prescribed nuclear facilities as projected at $1,851.3M (Ex. H2-1-1, Table 1, line 31, col. (c)). For instance, applying a rate of 5.58% would yield a return amount of $103.3M, while applying a rate of 5.43% (from Chart 2 in L-1-7 SEC-11), would yield $100.5M.

The discount rates of 4.8% and 3.43% represent the accounting discount (accretion) rates used to derive the amount of the net increases in OPG's nuclear ARO in 2010 upon the decision to proceed with the definition phase of the Darlington Refurbishment project and on December 31, 2011 arising from the 2012 ONFA Reference Plan update process, respectively. The former change in nuclear ARO determined at the 4.8% accretion rate is discussed in EB-2010-0008 Ex. C2-1-2, section 4.1. The latter change in nuclear ARO determined at the 3.43% accretion rate is discussed in Ex. H2-1-1 and L-1-1 Staff-02 b) and c). Each of the two nuclear ARO increases above represents a new tranche of the total nuclear ARO. As noted in Ex. H2-1-1, p. 4, lines 4-10, OPG's variable costs for the management of incremental used fuel and low and intermediate level waste for the 2010-2011 period and for 2012 are also calculated using discount rates of 4.8% and 3.43%, respectively, based on the most recent ARO tranche in effect.

Generally speaking, if a higher discount rate is used to calculate a new tranche of the nuclear ARO representing an increase in the escalated undiscounted cash flows, all else being equal, a lower amount of the ARO increase will result, and vice versa. Similarly, using a higher discount rate would decrease variable costs, and vice versa.

The rates of 4.8% and 3.43% represent credit-adjusted risk-free rates as required by CGAAP and USGAAP, as noted in L-2-1 Staff-20 a). They were established using the applicable Province of Ontario long-term provincial bond yields determined at the time when the corresponding tranches of the nuclear ARO were recognized. Yields on long-term provincial bonds were used to reflect the long-term nature and credit risk of the expected future cash flows in accordance with generally accepted accounting principles. (As shown in L-1-7 SEC-11, the rates of 4.8% and 3.43% are, in turn, used in the calculation of the weighted average accretion rate used for revenue requirement purposes, as described above.)

OPG has available the results of a hypothetical sensitivity specific to the 2011 year-end nuclear ARO adjustment, as disclosed in OPG's 2011 audited consolidated financial statements (Ex. A3-1-1, Attachment 1, p. 75, third paragraph). At that reference, the financial statements note that a ten basis points (0.1%) change in the discount rate of 3.43% used to derive the 2011 year-end upward ARO adjustment of $934M would change this adjustment by $8M- $9M.

SEC Interrogatory #13

Ref: H2/1/1, pp. 2-4

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, including all calculations, of all impacts on the balance in the Nuclear Liability Deferral Account resulting from changes in discount or interest rates since EB-2010-0008. For greater certainty, please include, in addition to all other impacts, the impact on each of the amounts in Table 3 of such changes in discount or interest rates.

Response

As discussed in L-1-7 SEC-12, the discount and interest rates impacting the balance in the Nuclear Liability Deferral Account have been established and/or calculated pursuant to specifically defined requirements in CGAAP/USGAAP, ONFA, and OEB's decisions and orders.

The impact of changes in interest and discount rates typically produce collateral impacts, which OPG has no basis to assess as discussed in L-1-07 SEC-06. Where possible and subject to stated assumptions, OPG provides the requested calculations of impacts from changes in discount or interest rates since EB-2010-0008 on the projected year-end 2012 balance in the Nuclear Liability Deferral Account presented in the pre-filed evidence.[1]

As discussed below, all components of the Nuclear Liability Deferral Account that are directly impacted by changes in discount or interest rates pertain to the nuclear asset retirement obligation ("ARO"). These are:

- Depreciation Expense
- Return on Rate Base
- Used Fuel Storage and Disposal Variable Expenses
- Low and Intermediate Level ("L&IL") Waste Management Variable Expenses
- Tax impacts associated with the above items

The impacts on the above items are based on a hypothetical ARO and asset retirement cost ("ARC") year-end 2011 adjustment recalculated using a discount rate of 4.8 per cent rather than the actual rate of 3.43 per cent, holding all else constant. This recalculation, including its limitations, is discussed in L-1-7 SEC-06, which requests similar impacts of discount or interest rate changes on the Bruce Lease Net Revenues Variance Account. The resulting hypothetical adjustment is provided in L-1-07 SEC-06, Attachment 2, Table 2, which is in the same format as the top portion of Ex. H2-1-1, Table 3. As shown in col. (d) of L-1-7 SEC-6,

[1] Secondary impacts on interest applied to the outstanding balance of the account have not been included.

Attachment 2, Table 2, the portion of the hypothetical adjustment attributable to the prescribed facilities would be $592.6M, as compared to $439.2M in col. (d) of Ex. H2-1-1, Table 3. The derivation of amounts in L1-7 SEC 6 Attachment 2, Table 2 is detailed in L1-7 SEC-6, Attachment 4.

As noted in L-1-7 SEC-06, a different projected 2012 depreciation expense of the ARC as well as projected 2012 variable expenses for used fuel and L&IL waste management would result from a different year-end 2011 ARO/ARC adjustment. A different adjustment would also result in a different average ARC value for 2012, thereby impacting the return on rate base amount recorded in the account for 2012. Table 1 in Attachment 1 to this response provides a calculation of the hypothetical 2012 additions to the Nuclear Liability Deferral Account, which includes the above hypothetical expense and return amounts.[2]

The details of the calculation of the above-noted depreciation expense and return on rate base are provided in Table 1, Attachment 1. As explained at Ex. H2-1-1, p. 6, lines 17-21, the variable expense component of account additions is calculated by applying new variable cost rates for 2012 to the forecast used fuel and waste volumes underpinning the EB-2010-0008 forecast variable expenses and then comparing the result to the forecast expenses. The details of this calculation for used fuel variable expenses, using the hypothetical variable cost rates resulting from using a 4.8 per cent discount rate, are provided in Attachment 2.[3] The impact on the L&IL waste management variable expense component of the 2012 account additions is small at less than $0.5M.

The income tax impacts resulting from the above recalculated amounts are calculated in Table 1, Attachment 1. The projected 2012 contributions to the segregated funds under the ONFA are considered not to be impacted by changes in discount or interest rates, as explained in L-1-7 SEC-06.

As attached Table 1 shows, based on the above, the hypothetical projected 2012 additions to the Nuclear Liability Deferral Account are $181.6M. This figure is very close to the projected 2012 additions to the account of $180.0M detailed at Ex. H1-1-1, Table 9 in the pre-filed evidence.

[2] As explained in section 5.0 of Ex. H2-1-1, there were no additions recorded in the account for 2011.
[3] The impact of discount rates on variable cost rates is discussed at Ex. H2-1-1, page 4, lines 4-10 and in response to interrogatory L-1-7 SEC-12.

Table 1
Hypothetical Nuclear Liability Deferral Account Balance[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Projected 2012
		(a)
	Hypothetical Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:	
1	**Depreciation Expense**[2]	110.6
	Return on Rate Base[3]	
2	**Average Asset Retirement Costs** (line 1a + ((line 1a - line 3a)) / 2	537.3
3	**Weighted Average Accretion Rate**	5.58%
4	**Return on Rate Base** (line 2 x line 3)	30.0
	Variable Expenses[4]	
5	**Used Fuel Storage and Disposal Variable Expenses**[5]	6.2
6	**Low & Intermediate Level Waste Management Variable Expenses**	0.7
7	**Total Variable Expenses** (line 5 + line 6)	6.9
	Income Tax Impact	
8	**Forecast Contributions to Nuclear Segregated Funds - EB-2010-0008**[6]	140.4
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan**[7]	185.7
10	**Increase in Contributions to Nuclear Segregated Funds** (line 8 - line 9)	(45.3)
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)	102.2
12	**Income Tax Rate**	25.0%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))	34.1
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)	181.6

Notes:

1 Unless otherwise noted, the calculation and the underlying information in this table is as reflected in Ex. H1-1-1, Table 9.

2 The depreciation expense component of the projected 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[#]	362.2	202.7	27.8	592.6
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))	36.2	73.7	0.7	110.6

Represents hypothetical adjustment on December 31, 2011 from L-1-7 SEC-06, Att. 2, Table 2, 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 projected addition to the deferral account has been determined by multiplying the forecast number of used fuel bundles and L&ILW volumes reflected in EB-2010-0008 payment amounts by 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 hypothetical 2012 rates arising from the current approved ONFA Reference Plan calculated using a discount rate of 4.8%.

5 As calculated in Ex. L-1-7 SEC-13, Att. 2, Chart 1.

6 From Ex. H1-1-1 Table 9, line 8.

7 From Ex. H1-1-1 Table 9, line 9.

ATTACHMENT 2

Chart 1
Hypothetical 2012 Used Fuel Variable Expense Component of Nuclear Liability Deferral Account Using 4.8% Discount Rate[1]

Prescribed Facility	Used Fuel Volume[2] (bundles) (a)	UFD Variable Cost Rate ($/bundle) (b)	UFS Variable Cost Rate ($/bundle) (c)	UFD Variable Expenses ($k) (d)=(a)x(b)	UFS Variable Expenses ($k) (e)=(a)x(c)	Total Used Fuel Variable Expense ($k) (f)=(d)+(e)
Pickering A	5,488	617	434	3,383	2,382	5,766
Pickering B	12,868	617	451	7,933	5,806	13,740
Darlington	23,069	617	42	14,223	974	15,197
Total		N/A	N/A	23,539	9,163	34,702
Less: EB-2010-0008 2012 Forecast Used Fuel Variable Expenses[3] ($k)						28,500
Nuclear Liability Deferral Account Addition for 2012 ($k)						6,201

[1] Numbers may not calculate due to rounding
[2] As reflected in the EB-2010-0008 forecast used fuel variable expenses for the prescribed facilities for 2012 (see note 3)
[3] From EB-2010-0008 Ex. C2-1-2, Table 1, line 4, col. (e)

SEC Interrogatory #14

Ref: H2/1/1,Table 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 and calculation of the 2012 costs included in lines 4 (UFSD Variable Expenses) and 26 (Depreciation Expense), and an explanation of the increases in those amounts from 2011 to 2012.

Response

Used Fuel Variable Expenses
The following Chart 1 provides a breakdown and calculation of projected 2012 used fuel storage ("UFS") and used fuel disposal ("UFD") variable expenses presented at line 4 in Ex. H2-1-1, Table 1 for the prescribed nuclear facilities.

Chart 1
Projected 2012 Used Fuel Variable Expenses for Prescribed Facilities[1]

Prescribed Facility	**Used Fuel Volume (bundles)** (a)	**UFD Variable Cost Rate ($/bundle)** (b)	**UFS Variable Cost Rate ($/bundle)** (c)	**UFD Variable Expenses ($k)** (d)=(a)x(b)	**UFS Variable Expenses ($k)** (e)=(a)x(c)	**Total Used Fuel Variable Expense ($k)** (f)=(d)+(e)
Pickering A	5,141	1,020	552	5,243	2,838	8,081
Pickering B	12,637	1,020	552	12,890	6,976	19,865
Darlington	22,963	1,020	58	23,422	1,332	24,754
Total	40,740	N/A	N/A	41,555	11,145	52,700

[1] Numbers may not calculate due to rounding

As noted at Ex. H2-1-1, page 4, lines 4-10, the projected used fuel variable expenses for the prescribed facilities are higher in 2012 than the actual expenses for 2011 mainly due to higher variable cost rates for 2012, calculated in present value terms, resulting from increases in UFS and UFD cost estimates as well as a lower discount rate in 2012. The higher cost estimates reflect the higher lifecycle liability baseline cost estimates for the UFS and UFD nuclear waste management programs based on the 2012 ONFA Reference Plan. As also stated in the reference above, the cost rates for 2012 reflect the discount rate of 3.43%, based on the most recent tranche of the nuclear asset retirement obligation ("ARO") as recorded on December 31, 2011 as a result of the 2012 ONFA Reference Plan update process, compared to 4.8% used to derive the 2011 cost rates based on the then-most recent ARO tranche.

<u>Depreciation Expense</u>

The following Chart 2 provides a breakdown and calculation of projected 2012 depreciation expense for the asset retirement costs (“ARC”) presented at line 26 in Ex. H2-1-1, Table 1 for the prescribed facilities.

Chart 2
Projected 2012 ARC Depreciation Expense for Prescribed Facilities[1]

	Pickering A	Pickering B	Darlington	Total
Net book value of ARC at Jan 1, 2012 ($M) *(A)*	385.7	148.9	1,379.8	1,914.7[2]
Remaining service life at Jan 1, 2012 (yrs)[3] (B)	10	2.75	40	N/A
2012 Depreciation Expense ($M) *(C)=(A)/(B)*	38.5	53.7	34.5	126.6

[1] Numbers may not calculate due to rounding
[2] Total opening ARC net book value as per Ex. H2-1-1, Table 1, line 25, col. (c)
[3] Based on average station end-of-life dates in effect as at December 31, 2011 of: December 31, 2021 for Pickering A, September 30, 2014 for Pickering B, December 31, 2051 for Darlington (from Ex. H1-1-1, Table 9, note 2)

The higher projected ARC depreciation expense in 2012 is due to the increase in the ARC for the prescribed facilities of $439.2M recognized on December 31, 2011 (Ex. H2-1-1, Table 3, top chart) as a result of the 2011 year-end ARO adjustment. Approximately $98M of additional ARC depreciation expense is projected in 2012 as a result of the above adjustment, as shown at Ex. H1-1-1, Table 9, line 1 and note 2.

SEC Interrogatory #15

Ref: L/1/1, Staff 4

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

Interrogatory

Please provide the "detailed calculations" referred to in part (a).

Response

Based on the inputs, assumptions and methodology provided and explained in L-1-1 Staff-04, the calculations for the actual 2011 and projected 2012 nuclear asset retirement obligation ("ARO") adjustments at year-end 2011 and year-end 2012, respectively, are provided below.

There are four steps in the derivation of the amounts in Ex. H2-1-1 Table 3. The impact on each of the four steps on each of the programs listed in Ex. H2-1-1 Table 3 is provided below. The assumptions provided in L-1-1 Staff-04 for the actual 2011 ARO adjustment are reflected Charts A.1, B.1, C.1, C.2 and D.1 below, while the assumptions for the projected 2012 ARO adjustment are reflected in Charts A.2, B.2, C.3, C.4 and D.2 below.

Developing ARO Cost Estimates For Each Of The Five Nuclear Waste Management And Decommissioning Programs
The cost estimates (cash flows) for the ARO are developed based on the cost estimates from the 2012 ONFA Reference Plan.

The following Chart A.1 provides the actual 2011 ARO cost estimates (cash flows from 2012 onward) in 2010 constant dollars ("2010 C$").

Chart A.1

A.1 2011 ARO 2010 C$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	1,598	1,636	2,106	5,340	1,731	1,484	3,215	8,555
Low and Intermediate Level Waste Storage Program	260	206	205	671	382	62	444	1,114
Low and Intermediate Level Waste Disposal Program	443	380	355	1,178	668	108	776	1,954
Used Fuel Disposal Program	1,693	1,689	5,728	9,109	4,597	2,939	7,536	16,646
Used Fuel Storage Program	392	339	629	1,359	497	477	974	2,333
Total ARO	**4,386**	**4,248**	**9,023**	**17,657**	**7,875**	**5,070**	**12,945**	**30,602**

*Numbers may not add due to rounding.

Similar to Chart A.1, the following Chart A.2 provides the projected 2012 ARO cost estimates (cash flows from 2013 onward) in 2010 C$.

Chart A.2

A.2 2012 ARO 2010 C$ ($M)*	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
Decommissioning Program	1,543	1,621	2,106	5,270	1,731	1,484	3,214	8,484
Low and Intermediate Level Waste Storage Program	232	208	188	628	363	68	432	1,059
Low and Intermediate Level Waste Disposal Program	406	393	334	1,133	654	123	777	1,910
Used Fuel Disposal Program	1,598	1,877	5,567	9,042	4,906	3,370	8,276	17,318
Used Fuel Storage Program	370	309	619	1,298	476	462	938	2,236
Total ARO	**4,150**	**4,407**	**8,814**	**17,371**	**8,129**	**5,507**	**13,637**	**31,007**

*Numbers may not add due to rounding.

Converting The Constant Dollar ARO Cost Estimates (Cash Flows) Into The Escalated Dollar ARO Cost Estimates (Cash Flows)

Since the cost estimates (cash flows) are originally developed in 2010 C$, a single long-term escalation rate for each of the cost elements (i.e., labour, materials and other) is used to escalate the constant dollar estimates. The resulting escalated cash flows form the bases for the updated ARO.

The escalation rates are based on long-term projections for Ontario from the Policy and Economic Analysis Program published by the University of Toronto. The escalation rates are 3.7% for labour costs, 2.0% for material costs and 1.9% for other costs and are applied to all programs in Charts B.1 and B.2.

The following Chart B.1 provides the 2011 ARO cost estimates (cash flows) in escalated dollars (“ESC$”).

Chart B.1

B.1 2011 ARO ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	5,330	4,548	18,380	28,257	11,305	4,820	16,126	44,383
Low and Intermediate Level Waste Storage Program	483	386	381	1,250	711	115	827	2,076
Low and Intermediate Level Waste Disposal Program	800	689	643	2,131	1,208	195	1,403	3,534
Used Fuel Disposal Program	15,735	15,668	53,913	85,316	43,648	27,480	71,128	156,444
Used Fuel Storage Program	658	554	1,629	2,841	1,123	927	2,050	4,891
Total ARO	**23,006**	**21,843**	**74,946**	**119,795**	**57,996**	**33,537**	**91,533**	**211,328**

*Numbers may not add due to rounding.

Similar to Chart B.1, the following Chart B.2 provides the 2012 ARO cost estimates (cash flows) in ESC$:

Chart B.2

B.2 2012 ARO ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	4,540	4,970	18,380	27,889	16,723	7,250	23,973	51,863
Low and Intermediate Level Waste Storage Program	442	399	358	1,200	694	131	825	2,025
Low and Intermediate Level Waste Disposal Program	745	724	613	2,082	1,201	226	1,427	3,509
Used Fuel Disposal Program	14,859	17,498	52,508	84,866	46,763	31,773	78,536	163,402
Used Fuel Storage Program	618	535	1,654	2,807	1,289	1,017	2,306	5,113
Total ARO	**21,204**	**24,126**	**73,513**	**118,843**	**66,670**	**40,397**	**107,067**	**225,910**

*Numbers may not add due to rounding.

Calculating The ARO Adjustment In Escalated Dollars

The adjustment in ESC$ is the incremental cash flow representing the annual differences between the updated ARO escalated cost estimates (from Charts B.1 and B.2 above) and the escalated cash flows underlying the unadjusted value of the ARO as of year-end in ESC$.

The following Chart C.1 provides the ESC$ cost estimates (cash flows) underlying the 2011 year-end actual value of the ARO prior to adjustment.

Chart C.1

C.1 2011 Unadjusted ARO Value ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	5,647	5,105	21,174	31,926	9,871	4,689	14,560	46,486
Low and Intermediate Level Waste Storage Program	160	156	189	505	244	45	289	793
Low and Intermediate Level Waste Disposal Program	246	237	457	940	455	87	542	1,482
Used Fuel Disposal Program	16,198	16,419	54,650	87,268	42,691	27,740	70,431	157,699
Used Fuel Storage Program	555	466	1,155	2,176	913	507	1,419	3,596
Total ARO	**22,807**	**22,383**	**77,625**	**122,815**	**54,174**	**33,067**	**87,241**	**210,056**

*Numbers may not add due to rounding.

The following Chart C.2 provides the cash flows for the actual 2011 year-end ARO adjustment in ESC$, as derived by subtracting the corresponding values in Chart C.1 from those in Chart B.1.

Chart C.2

C.2 2011 ARO Adjustment ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	(317)	(558)	(2,794)	(3,668)	1,434	132	1,566	(2,103)
Low and Intermediate Level Waste Storage Program	323	230	192	745	467	71	538	1,283
Low and Intermediate Level Waste Disposal Program	553	452	185	1,190	753	108	861	2,051
Used Fuel Disposal Program	(463)	(752)	(737)	(1,952)	957	(260)	697	(1,255)
Used Fuel Storage Program	103	88	474	664	210	421	631	1,295
Total Adjustment	**200**	**(541)**	**(2,679)**	**(3,020)**	**3,822**	**471**	**4,292**	**1,272**

*Numbers may not add due to rounding.

Similar to Chart C.1, the following Chart C.3 provides the ESC$ cost estimates (cash flows) underlying the projected 2012 year-end value of the ARO prior to adjustment.

Chart C.3

C.3 2012 Projected Unadjusted ARO Value ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	5,318	4,545	18,379	28,242	11,308	4,820	16,129	44,371
Low and Intermediate Level Waste Storage Program	469	374	370	1,214	690	113	802	2,016
Low and Intermediate Level Waste Disposal Program	787	678	633	2,098	1,190	192	1,382	3,480
Used Fuel Disposal Program	15,737	15,678	53,925	85,340	43,646	27,498	71,144	156,484
Used Fuel Storage Program	652	549	1,605	2,806	1,095	913	2,008	4,813
Total ARO	**22,964**	**21,825**	**74,912**	**119,700**	**57,928**	**33,536**	**91,464**	**211,164**

*Numbers may not add due to rounding.

Similar to Chart C.2, the following Chart C.4 provides the cash flows for the projected 2012 year-end ARO adjustment in ESC$, as derived by subtracting the corresponding values in Chart C.3 from those in Chart B.2.

Chart C.4

C.4 Projected 2012 ARO Adjustment ESC$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	(778)	425	0	(353)	5,415	2,430	7,845	7,492
Low and Intermediate Level Waste Storage Program	(27)	25	(12)	(14)	4	18	22	9
Low and Intermediate Level Waste Disposal Program	(42)	46	(20)	(16)	11	34	45	29
Used Fuel Disposal Program	(878)	1,820	(1,416)	(475)	3,118	4,274	7,392	6,918
Used Fuel Storage Program	(35)	(14)	49	1	194	105	298	299
Total Adjustment	**(1,760)**	**2,301**	**(1,398)**	**(857)**	**8,742**	**6,861**	**15,603**	**14,746**

*Numbers may not add due to rounding.

Calculating The ARO Adjustment In Present Value Terms

The adjustment cost flows are discounted to present value dollars (“PV$”) by applying a discount rate determined in accordance with CGAAP/USGAAP (see L-1-7 SEC-12).

The following Chart D.1 provides the actual 2011 year-end ARO adjustment (from Chart C.2) as converted into PV$ using the actual discount rate of 3.43%. The values in this chart are also found in the top portion of Ex. H2-1-1, Table 3.

Chart D.1

D.1 2011 ARO Adjustment PV$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	(111)	(209)	(296)	(616)	(188)	(194)	(383)	(999)
Low and Intermediate Level Waste Storage Program	126	84	64	274	183	27	210	483
Low and Intermediate Level Waste Disposal Program	245	195	36	477	317	42	359	836
Used Fuel Disposal Program	(31)	(60)	(104)	(195)	(8)	(26)	(34)	(229)
Used Fuel Storage Program	140	166	195	501	78	265	343	844
Total Adjustment	**368**	**176**	**(105)**	**439**	**382**	**113**	**495**	**934**

*Numbers may not add due to rounding.

Similar to Chart D.1, the following Chart D.2 provides the projected 2012 year-end ARO adjustment (from Chart C.4) as converted into PV$ using an assumed discount rate of 3.43%. The values in this chart are also found in the bottom portion of Ex. H2-1-1, Table 3.

Chart D.2

D.2 Projected 2012 ARO Adjustment PV$ ($M)*	**Pickering A**	**Pickering B**	**Darlington**	**Prescribed Facilities Total**	**Bruce A**	**Bruce B**	**Bruce Facilities Total**	**Total**
Decommissioning Program	(24)	(28)	0	(52)	(22)	(30)	(51)	(103)
Low and Intermediate Level Waste Storage Program	(13)	11	(6)	(8)	2	8	10	3
Low and Intermediate Level Waste Disposal Program	(22)	22	(11)	(11)	4	17	20	9
Used Fuel Disposal Program	(79)	141	(144)	(82)	246	330	576	494
Used Fuel Storage Program	(18)	(27)	14	(31)	8	(0)	7	(24)
Total Adjustment	**(157)**	**119**	**(146)**	**(184)**	**237**	**326**	**563**	**379**

*Numbers may not add due to rounding.

SEC Interrogatory #16

Ref: L1-1, Staff 4, p. 3

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

Interrogatory

Please provide the sensitivity analysis referred to.

Response

OPG declines to provide the sensitivity analysis on the basis of relevance. While OPG referred to the sensitivity analysis in L-1-1 Staff-4 for completeness of OPG's response, OPG's position is that the sensitivity analysis is irrelevant to the OEB's evaluation of the balances proposed for recovery in the Nuclear Liability Deferral Account.

Under Section 5.2 of O.Reg 53/05, OPG is entitled to record in a deferral account "the **revenue requirement impact of changes** in its total nuclear decommissioning liability between, (a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and (b) the liability arising from the current approved reference plan" (emphasis added).

Under paragraph 7 of section 6(2) O. Reg. 53/05, the Board is required to ensure that the balances recorded in the deferral accounts established under section 5.2 are recovered, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts. Paragraph 8 of section 6(2) requires the Board to ensure OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

The sensitivity analysis does not relate to the revenue requirement impacts recorded in the account and, as such, is irrelevant. The sensitivity analysis relates only to the assumptions underlying the current approved ONFA Reference Plan, which is not within the OEB's jurisdiction. OPG notes that in addition to being irrelevant, the analysis is also confidential.

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 #18

Ref: H2/2/1, 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 evidence that the $49.4 million claimed costs were incremental to the approved revenue requirement for 2011 and 2012. Please identify all cost reductions in other areas of the Applicant's operations resulting from this spending.

Response

OPG's evidence in EB-2010-0008 (Ex. D2-2-1, p. 16) states:

> The province has not yet determined the cost recovery mechanism for new nuclear. Accordingly, OPG has not included any capital or non-capital costs for new nuclear in its test period revenue requirement. If costs for planning and preparation of new nuclear arise in the test period and there is no new cost recovery mechanisms, they will be recovered through the Nuclear Development Variance Account, consistent with the requirements of O. Reg. 53/05.

Chart 3 on that same page confirms that zero dollars were included in the EB-2010-0008 revenue requirement for New Nuclear at Darlington ("NND") for both 2011 and 2012.

Exhibit H2-2-1, pages 2-3 explains the specific activities that were undertaken with respect to NND in 2011 and 2012. Further details on these activities are provided in response to L-1-7 SEC-17. As none of the costs for these NND activities were previously included in the revenue requirement, they are by definition incremental.

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

SEC Interrogatory #19

Ref: H2/2/1, p. 8

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 and explanation of the $11.4 million unfavourable variance in FCLM expenditures from forecast to actual. Please provide a side by side comparison of the detailed costs compared to Board-approved, in as much detail as possible. Please provide details of all additional personnel hired as a result of this additional spending, and all third party expenses such as contractor costs incurred.

Response

The $11.4M combined unfavourable variance consists of an unfavourable $2.4M variance to the 2011 Board-approved budget and an unfavourable $9.0M variance to the 2012 Board-approved budget.

Fuel Channel Life Cycle Management -Variance Summary

	2011 Actual $M	2011 Board Approved $M	Variance $M	2012 Projected $M	2012 Board Approved $M	Variance $M	Total 2011-2012 Variance $M
FCLM	10.1	7.7	2.4	13.0	4.0	9.0	11.4

The initial FCLM Project partial release Business Case Summary ("BCS") was approved on August 10, 2009 with projected spending of $24.9M over the period 2009 - 2013, including expenditures of $7.7M and $4.0M in 2011 and 2012 respectively. This BCS was filed in EB-2010- 0008 (Ex. F2-3-3, Attachment 1, Tab 16) and was the basis for the OEB approving FCLM expenditures of $7.7M in 2011 and $4.0M in 2012.

2011 Variance
The main driver to the $2.4M unfavourable variance in 2011 is that during project execution, new concerns were identified with the Darlington fuel channel spacers that required additional scope to be undertaken in 2011 for contractors to design and construct spacer crush test equipment and carry out testing. This additional scope represented approximately $3.0M in incremental contractor costs in 2011. OPG was also able to defer some planned

work to 2012. No additional external regular staff was hired for the FCLM Project as a result of this additional spending.

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2012 Variance

Additional project scope definition was undertaken as the project progressed. Additional investigation and testing scope was defined for execution in 2012 and approved by a second and third partial BCS. This additional scope represented approximately $6.1M in incremental contractor costs in 2012 as described below, along with $2.9M of other costs, resulted in an unfavourable variance of approximately $9.0M to the 2012 Board-approved budget.

The following is a detailed breakdown of the $6.1M in additional scope of work costs:

Additional Project 2012 Contracted Costs	$M
Design and construct a test rig for spacer material fatigue tests	1.2
Additional modelling of helium production in spacer material due to irradiation	0.2
Additional study of relaxation of spacer material due to helium production and associated mobility issues	0.3
Investigation of spacer material accelerated irradiation test requirements and scope	0.3
Additional study of pressure tube material recovery during hydriding process	1.3
Additional scope to support fracture toughness model development including small sample testing and metallography	0.5
Additional pressure tube section burst tests	0.8
Additional support for development of hydriding technique	1.5
Total	**6.1**

The other $2.9 M of costs represent higher than originally planned costs to complete originally planned work, costs for additional resources to improve project oversight and execution to ensure project success and execution of 2011 deferred planned work. No additional external regular staff was hired for the FCLM Project as a result of this additional spending.

SEC Interrogatory #20

Ref: H2/1/3

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, including all calculations, of all impacts on the balance in the Pension and OPEB Cost Variance Account resulting from changes in discount or interest rates since EB-2010-0008. For greater certainty, please include in the breakdown all of the rate differentials referred to in Chart 1 on page 6 (as amended in L/2/1, Staff 24), as well as any other impacts of rate changes.

Response

OPG is able to estimate the impact of different discount rate assumptions on its pension and OPEB costs, as discussed below. However, OPG has no basis on which to determine other impacts on pension and OPEB amounts as a result of changes in interest rates since EB-2010-0008. For example, OPG cannot determine what an appropriate long-term inflation rate assumption would be for the hypothetical macroeconomic environment that produced different interest rates. Additionally, as with any investment portfolio, asset returns for pension fund assets would be impacted by the level of interest rates, but OPG has no basis on which to judge how capital markets would have performed had interest rates remained at the same levels as in EB-2010-0008.

As noted in Ex. H2-1-3, p. 7, lines 13-16, the discount rates used in the calculation of 2011 and 2012 pension and OPEB costs, and therefore the resulting variances recorded in the Pension and OPEB Cost Variance Account, have been determined in accordance with CGAAP and were provided by independent actuaries. For the reasons above, OPG views the calculations of the impact of a different discount rate assumption as having limited value to the OEB or intervenors.

Nevertheless, based on information in the pre-filed evidence, OPG's independent actuary has provided OPG with an estimate of hypothetical OPG-wide CGAAP actual (2011) and projected (2012) pension and OPEB costs using discount rates from EB-2010-0008 as shown in Chart 1 at p. 6 of Ex. H2-1-3 and Chart 1, as Amended in Ex. L-2-1 Staff-24, holding all other variables constant. The regulated portion of these hypothetical costs for the period March 1, 2011 to December 31, 2012, as well as the actual (2011) or projected (2012) costs for that period from the pre-filed evidence and resulting differences are provided at Attachment 1, Table 1, on the same basis as in the pre-filed evidence. The table also includes a calculation of the consequent difference in the regulatory income tax impact.

At line 11, columns (h) and (j), respectively, the attached Table 1 shows the total of the above differences at $22.5M for regulated hydroelectric and $446.4M for nuclear. Therefore, if the same discount rates as in EB-2010-0008 were used to calculate the actual (2011) and projected (2012) pension and OPEB costs, the hypothetical additions to the Pension and OPEB Cost Variance Account over that period would be lower by these amounts. This result is consistent with OPG's pre-filed evidence that, at Ex. H2-1-3, p. 6, lines 11-12, indicates that "lower than forecast discount rates are the primary source of variance recorded in this account."

Table 1

Pension and OPEB Cost Variance Account[1]

Summary of Hypothetical Discount Rate Differences - March to December 2011 and 2012 ($M)

Line No.	Particulars	Mar - Dec 2011			Projected 2012			Total Mar - Dec 2011 and 2012		
		Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Hypothetical Pension Costs**[2]	4.6	95.6	100.2	5.2	100.4	105.6	9.8	196.0	205.8
2	**Hypothetical OPEB Costs**[2]	6.5	134.3	140.8	8.3	162.0	170.3	14.8	296.3	311.1
3	**Total Hypothetical Pension and OPEB Costs**	11.1	229.9	241.0	13.5	262.4	275.9	24.6	492.3	516.9
4	**Actual/Projected Pension Costs**[3]	7.8	162.2	170.0	14.8	287.0	301.8	22.6	449.2	471.8
5	**Actual/Projected OPEB Costs**[3]	7.7	160.3	168.1	11.0	215.7	226.7	18.7	376.0	394.8
6	**Total Actual/Projected Pension and OPEB Costs**	15.6	322.5	338.1	25.8	502.7	528.5	41.4	825.2	866.6
7	**Difference Between Actual/Projected and Hypothetical Pension Costs** (line 4 - line 1)	3.2	66.6	69.8	9.6	186.6	196.2	12.8	253.2	266.0
8	**Difference Between Actual/Projected and Hypothetical OPEB Costs** (line 5 - line 2)	1.2	26.0	27.3	2.7	53.7	56.4	3.9	79.7	83.7
9	**Total Difference in Pension and OPEB Costs**	4.5	92.6	97.1	12.3	240.3	252.6	16.8	332.9	349.7
10	**Difference in Regulatory Income Tax Impact**[4] (line 9 x tax rate / (1 - tax rate))	1.6	33.4	35.0	4.1	80.1	84.2	5.7	113.5	119.2
11	**Total Hypothetical Discount Rate Difference** (line 9 + line 10)	6.1	126.0	132.1	16.4	320.4	336.8	22.5	446.4	468.9

Notes:

1 All cost amounts are presented on a CGAAP basis.

2 Amounts for 2011 represent 10/12 of the full year hypothetical 2011 costs. The hypothetical 2011 and 2012 amounts were calculated on the same basis as those at lines 4 and 5, but using forecast discount rates provided in EB-2010-0008, rather than the actual rates, all else being held constant.
The hypothetical costs for full year 2011 are as follows for regulated hydroelectric and nuclear, respectively: $5.5M and $114.7M for pension, and $7.8M and $161.1M for OPEB.

3 Cols. (a)-(f) from Ex. H1-1-1, Table 5, lines 4 and 5.

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

SEC Interrogatory #21

Ref: H2/1/3, p. 3

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

Interrogatory

Please confirm that the words "consistent with" used in line 6 mean there were no changes to the methodology.

Response

Confirmed; as explained in the pre-filed evidence, Ex. H2-1-3, page 2, lines 24-26: "The same accounting standards and actuarial methodology were applied in determining 2011 (actual) and 2012 (projected) pension and OPEB costs as those reflected in the EB-2010-0008 payment amounts."

SEC Interrogatory #22

Ref: H2/1/3, p. 8

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

Interrogatory

Please confirm that the adjustments to pension and OPEBs future liabilities do not have any actual tax impact, but recovery from ratepayers of those accrued amounts will increase taxable income as those recoveries occur.

Response

OPG understands "adjustments to pension and OPEBs future liabilities" to refer to the changes in pension and OPEB costs that are recorded in the Pension and OPEB Cost Variance Account and determined on an accounting (accrual) basis as reflected in the approved revenue requirement for OPG.

As noted in Ex. H2-1-3, section 3.3, OPG can confirm that pension and OPEB accounting costs are not deductible for income tax purposes under the *Income Tax Act* (Canada) and, therefore, their incurrence, in and of itself, does not have an immediate impact on OPG's income taxes payable. OPG can also confirm that the recovery from ratepayers of pension and OPEB costs does increase OPG's taxable income resulting in higher income taxes payable by the company.

As discussed in L-7-7 SEC-34 in the context of the Impact for USGAAP Deferral Account, in order to offset the additional income taxes payable by OPG upon recovery, the income tax impact must be included as part of the disposition of the balance to enable OPG to recover the variance in pension and OPEB accounting costs. The OEB's establishment of the Pension and OPEB Cost Variance Account in EB-2011-0090 accepts that there are actual tax impacts and specifically identifies "associated tax impacts" as part of the variance to be recorded in the account, as discussed in Ex. H2-1-3, pp. 1 and 2.[1]

[1] Such associated income tax impacts were also included in the calculation of the deferral account balance put forward by OPG in that proceeding (EB-2011-0090, OPG's Notice of Motion, Exhibit C to the affidavit of N. Reeve).

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.

Numbers may not add due to rounding.

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

Line No.	Particulars	Projected 2013 Hydroelectric	Projected 2013 Nuclear	Projected 2013 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%.

Numbers may not add due to rounding.

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]	17.8	352.0	369.8
5	**Projected OPEB Costs**[3]	11.5	226.6	238.1
6	**Total Projected Pension and OPEB Costs**	29.3	578.6	607.9
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)	10.9	213.6	224.5
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)	3.4	63.6	67.0
9	**Addition to Variance Account - Regulatory Tax Impact**[4]	3.7	72.2	75.8
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)	17.9	349.4	367.2

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. 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.

3 Projected amounts are based on assumptions used in the preparation of the EB-2012-0002 pre-filed evidence.

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	Nuclear	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)	17.8	352.0	369.8
3	**OPEB Costs**[3] (from Ex. L-1-7 SEC-23 Table 1, line 5)	11.5	226.6	238.1
4	**Less: Pension Plan Contributions**[3]	12.3	242.9	255.2
5	**Less: OPEB Payments**[3]	4.5	88.2	92.7
6	**Net Additions to Regulatory Earnings Before Tax**	12.5	247.5	260.0
7	**Projected Regulatory Income Tax Impact**[4] (line 6 x tax rate / (1 - tax rate))	4.2	82.5	86.7
8	**Addition to Variance Account - Regulatory Tax Impact** (line 7 - line 1)	3.7	72.2	75.8

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.
Specifically, amounts at line 1, cols. (a) and (b) are from Ex. H1-1-1, Table 5a, line 1, cols. (d) and (e), respectively.

3 Projected amounts are based on assumptions used in the preparation of the EB-2012-0002 pre-filed evidence.

4 Tax rate for 2013 is 25.00%.

SEC Interrogatory #24

Ref: H1/1/1, Table 15

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

Interrogatory

Please confirm that the Applicant proposes to recover $16.3 million ($7.4+8.9) from ratepayers out of this account because nuclear production over the period March 2011 to December 2012 is forecast to be 3.7 TWh (4.0%) below forecast, resulting in an under-recovery of deferral and variance account balances from prior periods.

Response

OPG confirms that the projection of nuclear production from March 2011 to December 2012 in the pre-filed evidence is 3.7 TWh below the OEB approved EB-2010-0008 nuclear production forecast. The approved forecast increased OPG's filed nuclear production forecast production by a total of 3 TWh (i.e.,1.5 TWh per year for 2011 and 2012). OPG also confirms that this results in a projected under-recovery of $16.3M for the OEB-approved December 31, 2010 nuclear deferral and variance account balances and that this under-recovery is being recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the actual December 31, 2012 balance of which OPG seeks to clear in this Application.

OPG is recording amounts in the Nuclear Deferral and Variance Over/Under Recovery Variance Account pursuant to the EB-2010-0008 Payment Amounts Order. In that order, the OEB authorized the continuation of this account effective March 1, 2011 "to record differences between the amounts approved for recovery in the nuclear variance and deferral accounts and the actual amounts recovered resulting from the differences between the forecast and actual nuclear production." (EB-2010-0008 Payment Amounts Order, Appendix F, p. 7)[1]

Similarly, in this Application, OPG is also seeking to refund to ratepayers the actual amount recorded into the equivalent Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, as also authorized by the OEB in EB-2010-0008.[1] The pre-filed evidence at Ex. H1-1-1, Table 7, line 5 shows a projected credit to customers of $3.1M ($1.2M+$0.2M+$1.7M) by December 31, 2012 related to the projected hydroelectric production variance.

[1] The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts were originally established in EB-2009-0174.

Board Staff Interrogatory #15

Ref: Exh H1-1-1 Tables 1, 1a, 1b and 1c

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

Interrogatory

a) Please provide a new table (e.g. "Table 1d") for all deferral and variance account balances showing only the "additions" (i.e., new principal transactions and associated carrying charges arising in each of the following three periods shown separately and the grand totals (for these additions) as at December 31, 2012.
i. January to February 2011(as applicable);
ii. March to December 2011; and
iii. January to December 2012.

b) Please confirm that the proposed grand totals as at December 31, 2012 (covering the three periods from January 1, 2011 to December 31, 2012) for each deferral and variance account represent the new "addition" amounts OPG is seeking approval to recover from (or refund to) ratepayers since the last payment order (EB-2010-0008).

c) Please provide a new table (e.g. "Table 1e") showing the current approved deferral and variance account balances approved as at December 31, 2010 in the last payment order (EB-2010-008) with no (subsequent) additions covering the three periods shown in a) above and the grand totals as at December 31, 2012

d) Please confirm that the sum of the grand totals in the two tables above in a) and c) match the totals in column (d) in Table 1 and column (f) in Table 1c. If not, please explain the difference.

Response

a) See attached Table 1d.

b) Confirmed, with the exception that "additions" to accounts that were or are to be terminated as of December 31, 2011 and 2012 shown in Table 1d are reflected in the 2012 year-end balances of the Hydroelectric and Nuclear Deferral and Variance Over/Under Recovery Variance Accounts that OPG is seeking to recover from (or refund to) ratepayers as presented in Ex. H1-1-1 Tables 1-1c.

c) See attached Table 1e.

d) Confirmed, with the exception noted in part (b) and that the year-end 2012 balance of the terminated Pickering A Return to Service Deferral Account shown in Table 1e is reflected in the 2012 year-end balance of the Nuclear Deferral and Variance Over/Under Recovery Variance Account in Ex. H1-1-1 Table 1, col. (d) and Table 1c, col. (f), as per the EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Table 1d
Deferral and Variance Accounts
Transactions and Interest - 2011 and 2012 ($M)

Line No.	Account	January - February 2011			March - December 2011			Projected January - December 2012			Grand Total
		Transactions[1]	Interest[1]	Total	Transactions[2]	Interest[2]	Total	Transactions[3]	Interest[3]	Total	
		(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (d) + (e)	(g)	(h)	(i) = (g) + (h)	(j) = (c) + (f) + (i)
	Regulated Hydroelectric:										
1	**Hydroelectric Water Conditions Variance**	1.0	(0.2)	0.8	(3.2)	(0.7)	(3.9)	13.7	(0.3)	13.4	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	1.6	0.0	1.6	14.1	0.0	14.1	16.6	0.3	16.9	32.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	0.0	(1.4)	0.0	(1.4)	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.0	0.5	0.0	0.5	4.4	0.0	4.4	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(2.2)	0.0	(2.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(2.6)
6	**Tax Loss Variance - Hydroelectric**	5.2	0.2	5.4	0.0	0.9	0.9	0.0	0.8	0.8	7.1
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	0.0	(0.7)	0.0	0.0	0.0	1.8	0.0	1.8	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	0.0	4.0	0.0	4.0	12.6	0.1	12.7	16.7
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	2.7	2.7
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(1.2)	0.0	(1.2)	(0.2)	(0.1)	(0.3)	(1.7)	(0.1)	(1.8)	(3.4)
12	**Total**	3.6	0.0	3.6	13.7	0.0	13.7	50.0	0.7	50.7	68.0
	Nuclear:										
13	**Pickering A Return To Service (PARTS) Deferral**	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.2
14	**Nuclear Liability Deferral**	0.0	0.1	0.1	0.0	0.3	0.3	180.0	1.3	181.3	181.7
15	**Nuclear Development Variance**	(7.9)	(0.3)	(8.2)	14.5	(1.0)	13.5	32.1	(0.2)	31.9	37.2
16	**Transmission Outages and Restrictions Variance**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.1	0.0	0.1	0.5	0.0	0.5	0.9	0.0	0.9	1.4
18	**Capacity Refurbishment Variance - Nuclear**	0.5	(0.0)	0.5	4.4	(0.0)	4.4	8.3	0.1	8.4	13.3
19	**Nuclear Fuel Cost Variance**	5.8	0.0	5.8	0.0	0.1	0.1	0.0	0.1	0.1	6.0
20	**Bruce Lease Net Revenues Variance**	(13.6)	0.6	(13.0)	70.4	2.5	72.9	305.2	3.1	308.3	368.2
21	**Income and Other Taxes Variance - Nuclear**	(8.1)	(0.1)	(8.2)	(17.1)	(0.4)	(17.5)	(5.4)	(0.5)	(5.9)	(31.6)
22	**Tax Loss Variance - Nuclear**	27.3	1.0	28.3	0.0	4.8	4.8	0.0	4.4	4.4	37.5
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	0.0	91.9	0.5	92.4	237.7	3.0	240.7	333.1
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0	55.9	0.8	56.7	56.7
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.1
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	(9.4)	0.0	(9.4)	7.4	0.2	7.6	8.9	0.0	8.9	7.0
27	**Total**	(5.3)	1.4	(3.9)	171.9	7.2	179.0	823.4	12.1	835.5	1,010.7
28	**Grand Total**	(1.7)	1.4	(0.3)	185.5	7.2	192.7	873.4	12.8	886.2	1,078.6

Notes:
1 From Ex. H1-1-1 Table 1a
2 From Ex. H1-1-1 Table 1b
3 From Ex. H1-1-1- Table 1c

Table 1e
Deferral and Variance Accounts
Amortization - 2011 and 2012 ($M)

Line No.	Account	Approved Year End Balance 2010[1]	Amortization[2]				Projected Year End Balance 2012
			Jan-Feb 2011	Mar-Dec 2011	2012	Total	
		(a)	(b)	(c)	(d)	(e) = (b)+(c)+(d)	(f) = (a) - (e)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(70.2)	0.0	31.9	38.3	70.2	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(9.4)	0.0	4.3	5.1	9.4	0.0
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)	0.0	3.7	4.4	8.1	0.0
6	**Tax Loss Variance - Hydroelectric**	78.8	0.0	(17.1)	(20.6)	(37.7)	41.1
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
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	1.0	1.2	2.3	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(7.9)	0.0	3.6	4.3	7.9	0.0
12	**Total**	(19.1)	0.0	27.3	32.8	60.2	41.1
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**	33.2	(8.2)	(33.2)	0.0	(41.4)	(8.2)
14	**Nuclear Liability Deferral**	39.2	0.0	(17.8)	(21.4)	(39.2)	0.0
15	**Nuclear Development Variance**	(110.8)	0.0	50.4	60.4	110.8	0.0
16	**Transmission Outages and Restrictions Variance**	0.1	0.0	(0.0)	(0.0)	(0.1)	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.6	0.0	(0.3)	(0.3)	(0.6)	0.0
18	**Capacity Refurbishment Variance - Nuclear**	(8.5)	0.0	3.9	4.6	8.5	0.0
19	**Nuclear Fuel Cost Variance**	6.4	0.0	(2.9)	(3.5)	(6.4)	0.0
20	**Bruce Lease Net Revenues Variance**	249.4	0.0	(113.4)	(136.0)	(249.4)	0.0
21	**Income and Other Taxes Variance - Nuclear**	(31.6)	0.0	14.3	17.2	31.6	0.0
22	**Tax Loss Variance - Nuclear**	413.7	0.0	(89.9)	(107.9)	(197.8)	215.8
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	(3.0)	(3.6)	(6.6)	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	20.8	0.0	(9.5)	(11.4)	(20.8)	0.0
27	**Total**	619.0	(8.2)	(201.4)	(201.8)	(411.4)	207.7
28	**Grand Total**	600.0	(8.2)	(174.0)	(169.0)	(351.2)	248.8

Notes:
1 Year end balances as of December 31, 2010 approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.
2 Col. (b) from Ex. H1-1-1 Table 1a. Col. (c) from Ex. H1-1-1 table 1b. Col. (d) from Ex. H1-1-1 Table 1c.

Board Staff Interrogatory #16

Ref: Ref: Exh H1-1-1 Table 15 and Table 7

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

Interrogatory

Table 15 summarizes transactions for the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

a) Please confirm whether the "Mar-Dec 2011" addition to the Nuclear Deferral and Variance Over/Under Recovery Variance Account should be $6.5M instead of $7.4M based on the following calculations and sources:

- Line 6 column (b) = 42 TWh (i.e., 50.4 TWh x (10/12); Line 7 column (b) = 40.5 TWh (i.e., 48.6 x (10/12); Line 8 column (b) = 1.5 TWh (i.e., 42 TWh – 40.5 TWh;); Line 9 column (b) = $4.33 TWh and; Line 10 column (b) = $6.5M (i.e., 1.5 TWh x $4.33 per MWh) Source:
- Source: Line 6 column (b) = 50.4 TWh based on the 2011 approved production in the Payment Amounts Order EB-2010-0008 Appendix A Table 3
- Source: Line 7 column (b) = 48.6 TWh per EB-2012-0002 Ex. A3-1-1 Attachment 1 page 12 MD&A

b) Please provide a summary of the transactions in this account for the period from January 2011 to December 2012 (projected) including the transfers from the various accounts to this account.

c) With respect to Table 15, please provide the 2011 and 2012 nuclear forecast production by month and actual production, if available.

d) With respect to Table 7, please provide the 2011 and 2012 regulated hydroelectric forecast production by month and actual production, if available.

Response

a) Not confirmed.

The question presumes that both forecast and actual nuclear production for 2011 are the same in every month while account entries are based on production which varies on a monthly basis. The actual nuclear production for full year 2011 is correctly sourced as 48.6 TWh. However, when trended on a monthly basis as shown in part c) below, the production was 8.8 TWh in January and February 2011 (as shown at Ex. H1-1-1, Table 15, Line 2, col. (a)) and 39.8 TWh in March to December 2011 (as shown at Ex. H1-1-1,

Table 15, Line 7, col. (b)). As per note 4 to Table 15, the forecast production for March to December 2011 shown at Line 6, col. (b) in the Table reflects the monthly trending underlying the full-year approved forecast of 50.4 TWh from the EB-2010-0008 Payment Amount Order (as shown in part c) below).

b) The requested summary is provided in Table 1, attached.

c) and d)

The 2011 and 2012 EB-2010-0008 forecast, 2011 actual and 2012 actual/ projected regulated hydroelectric production values, by month, are provided in attached Table 2. The 2011 and 2012 EB-2010-0008 forecast, 2011 actual and 2012 actual/projected nuclear production values, by month, are provided in attached Table 3.

Numbers may not add due to rounding.

Table 1
Summary of Transactions in Nuclear Deferral and Variance Over/Under Recovery Variance Account

Line No.	Period	Additions	Amortization	Interest	Transfers	Total Transactions
		(a)	(b)	(c)	(d)	(e)
1	January - February 2011 (Ex H1-1-1 Table 1a, Line 26)	(9.4)	0.0	0.0	0.0	(9.4)
2	March - December 2011 (Ex H1-1-1 Table 1ba, Line 26)	7.4	(9.5)	0.2	(8.0)	(9.9)
3	Projected 2012 (Ex H1-1-1 Table 1c, Line 26)	8.9	(11.4)	0.0	6.1	3.6
4	Total	6.8	(20.8)	0.2	(1.9)	(15.7)

Numbers may not add due to rounding.

Table 2
Regulated Hydroelectric
Monthly Forecast and Actual/Projected Production - 2011 and 2012 (TWh)

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2011:													
1	**Forecast Production - EB-2010-0008**[1]	1.7	1.5	1.7	1.7	1.8	1.7	1.7	1.7	1.6	1.6	1.6	1.7	19.8
2	**Actual Production**[2]	1.6	1.4	1.7	1.5	1.7	1.7	1.7	1.7	1.6	1.7	1.6	1.7	19.5
	2012:													
3	**Forecast Production - EB-2010-0008**[1]	1.6	1.6	1.7	1.6	1.8	1.7	1.7	1.7	1.6	1.6	1.6	1.7	19.8
4	**Actual /Projected Production**[2]	1.6	1.6	1.7	1.6	1.6	1.5	1.6	1.5	1.4	1.4	1.6	1.6	18.8

Notes:
1 Based on amounts reflected in the EB-2010-0008 Payment Amounts Order
2 Actual for January to June 2012; projection for July to December 2012 as presented in EB-2012-0002 pre-filed evidence

Numbers may not add due to rounding.

Table 3
Nuclear
Monthly Forecast and Actual/Projected Production - 2011 and 2012 (TWh)

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2011:													
1	**Forecast Production - EB-2010-0008**[1]	4.8	4.1	4.3	3.7	3.8	3.9	4.8	4.7	4.2	4.1	4.0	4.1	50.4
2	**Actual Production**[2]	4.7	4.1	3.8	3.7	4.1	3.7	4.0	4.6	4.0	3.9	3.9	4.2	48.6
	2012:													
3	**Forecast Production - EB-2010-0008**[1]	4.8	4.2	4.3	3.7	3.8	4.4	4.8	4.8	4.2	4.1	4.0	4.4	51.5
4	**Actual /Projected Production**[2]	4.4	4.1	4.0	3.5	4.0	4.2	4.6	4.6	4.1	4.0	3.8	4.2	49.5

Notes:
1 Based on amounts reflected in the EB-2010-0008 Payment Amounts Order
2 Actual for January to June 2012; projection for July to December 2012 as presented in EB-2012-0002 pre-filed evidence

Board Staff Interrogatory #17

Ref: Exh H1-1-1 page 5 and Table 4

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

Interrogatory

Please provide references to previous proceedings and any further information to support the allocation of amounts between regulated hydroelectric and nuclear in the Income and Other Taxes Variance Account.

Response

Requested references/information are/is provided below for each of the six entries into the Income and Other Taxes Variance Account described starting at line 18 on page 5 of Ex. H1-1-1. Interest on the account balance is calculated separately for each of regulated hydroelectric and nuclear on the basis of the amounts of the entries attributed to each business.

(i) and (ii) Scientific Research and Experimental Development Investment Tax Credits and Expenditure. Amounts are attributed to each of regulated hydroelectric and nuclear using the same methodology as outlined in EB-2010-0008, Ex. L-1-139.

(iii) Income Tax Variance Due to Income Tax Rate Reduction. Amounts are calculated using the total forecast (benchmark) regulatory taxable income for April 1, 2008 to December 31, 2009 (EB-2010-0008 Ex. F4-2-1, section 5.1 and Ex. F4-2-1, Table 9). As the forecast income tax expense was neither calculated nor reviewed on a technology-specific basis, it was allocated between regulated hydroelectric and nuclear using an administratively simple approach of equal allocation between the two technologies. The tax expense resulting from this allocation was reflected in the EB-2010-0008 nuclear and hydroelectric payment amount riders approved by the OEB.

(iv) Income Tax Variance Due to Unburned Nuclear Fuel Adjustment. Amount is for unburned nuclear fuel and is therefore directly attributed to nuclear.

(v) Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment. Amount is for nuclear waste management capital expenditures and is therefore directly attributed to nuclear.

(vi) Capital Tax Variance Due to Capital Tax Elimination. Amounts are calculated using the total forecast net taxable capital amounts for April 1, 2008 to December 31, 2009 (EB-2007-0905, Ex. F3-2-1, section 5.0 and Ex. F3-2-1, Tables 2 and 5) and are attributed to each of regulated hydroelectric and nuclear based on the allocation of the capital tax expense. The

tax expense resulting from this allocation was reflected in the EB-2010-0008 nuclear and hydroelectric payment amount riders approved by the OEB.

Board Staff Interrogatory #18

Ref: OPG 2011-2012 Payment Amounts Application (EB-2010-0008)
Exh H2-1-1
Exh H1-1-1 Table 9

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

Interrogatory

As noted in Exh C2-1-1 of the evidence filed in EB-2010-0008, the ONFA Reference Plan must be updated every five years or whenever there is a significant change. The Reference Plan that underpins the 2011-2012 payments amounts was approved by the Province in December 2006. The pre-filed evidence in the current proceeding documents that the current ONFA Reference Plan was approved by the Province effective January 1, 2012.

The pre-filed evidence in H2-1-1 refers to approved discount rates. Please provide a comparison of approved discount rates in the Reference Plan approved in December 2006 with the ONFA Reference Plan effective January 1, 2012.

Response

As prescribed by the ONFA, the approved discount rate is a real rate of return of 3.25 per cent plus the forecasted long-term Ontario Consumer Price Index ("CPI") rate. For both the ONFA Reference Plan approved in December 2006 and the 2012 ONFA Reference Plan, the long-term Ontario CPI, as sourced from an independent third party, was forecasted at 1.9 per cent, which resulted in the same approved discount rate of 5.15 per cent (3.25%+1.9%) for both Reference Plans.

Board Staff Interrogatory #19

Ref: OPG 2011-2012 Payment Amounts Application (EB-2010-0008)
Exh H2-1-1
Exh H1-1-1 Table 9

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

Interrogatory

At pages 2-3 of Exh H2-1-1, it states:

> The current approved ONFA Reference Plan is projected to result in higher accounting nuclear liabilities costs 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.
> - Increase in the fixed costs arising from a higher number of used fuel bundles and amount of L&ILW to be managed. This increase results from the projected accounting implementation at the end of 2012 of the changes in estimated service lives of Pickering A and B and Bruce A and B units as contained in the current approved ONFA Reference Plan. The changes in the average service lives, for accounting purposes, of the Bruce A and B stations are discussed in Ex. H2-1-2. Similar changes for Pickering A and B are expected based on OPG's high confidence with respect to the extended service lives of their pressure tubes, as discussed in Ex. H2-2-1.
> - The above increases are partially offset by a reduction in decommissioning costs due to several factors including longer station operating lives that reduce the present value of the decommissioning liability, the assumed co-location of decommissioning L&ILW waste with operational waste in the Kincardine DGR, and a more defined characterization of waste in the nuclear facilities that reduces the amount of expensive, higher dose dismantlement work.

a) Note 2 of Table 9 at Exh H1-1-1 lists the useful life of Pickering A, Pickering B and Darlington at December 31, 2011. Please confirm whether the useful lives summarized in Note 2 are the same as the useful lives that underpin the 2011-2012 payment amounts.

b) Please provide the "longer station operating lives" that contribute to the $180M projected 2012 year-end balance in the Nuclear Liability Deferral Account. Are these "longer station operating lives" specifically referenced in the ONFA Reference Plan effective January 1, 2012?
c) At pages 7-8 of Exh H2-2-1, OPG states that the fuel channel life cycle management program:

… will confirm that the refurbishment of Darlington can begin in 2016 and will not need to be advanced. The work also supports the determination of high confidence that Pickering can maintain fitness for service to 2020 end-of life. In December 2012, a high confidence statement regarding the service lives of pressure tubes based on available research and development ("R&D") results Pickering and Darlington will be presented to the OPG Board of Directors in order to make business decisions on the continued operations of Pickering and the refurbishment of Darlington.

Please clarify whether refurbishment of Darlington commencing in 2016 and Pickering 2020 end-of-life have been approved by the OPG Board of Directors. If yes, when was the approval provided? If no, what operating life has been approved for these stations at the time of the filing of the current application?

d) Please provide copies of the approved 2010 and 2011 Depreciation Review Committee Reports for the Regulated Business.

Response

a) Confirmed

b) As noted in the third bullet cited in the preamble to the question, for accounting purposes, the longer station lives for Pickering Units 5-8 and the Bruce units are being implemented at the end of 2012, not January 1, 2012, based on the achievement of high confidence with respect to their extended service lives. As such, the projected 2012 additions to the Nuclear Liability Deferral Account of $180M do not reflect the impact of the extended estimated end-of-life dates shown below on OPG's nuclear liabilities.

The estimated station lives presented below are specifically referenced in the approved 2012 ONFA Reference Plan:[1]

[1] Calculations underlying the approved 2012 ONFA Reference Plan and OPG's nuclear liabilities are based on unit end-of-life dates that are rounded to the nearest calendar year-end (i.e., rounded down to the end of the previous year if the end-of-life date is in Q1 or Q2, and rounded up to the end of the year if it is in Q3 or Q4).

Unit	End-of-Life Date
Pickering A – Unit 1	2019
Pickering A – Unit 4	2019
Pickering B – Unit 5	2017
Pickering B – Unit 6	2017
Pickering B – Unit 7	2019
Pickering B – Unit 8	2019
Bruce A – Unit 1	2042
Bruce A – Unit 2	2042
Bruce A – Unit 3	2054
Bruce A – Unit 4	2054
Bruce B – Unit 5	2018
Bruce B – Unit 6	2019
Bruce B – Unit 7	2019
Bruce B – Unit 8	2021
Darlington – Unit 1	2050
Darlington – Unit 2	2048
Darlington – Unit 3	2051
Darlington – Unit 4	2053

The 2012 ONFA Reference Plan approved effective January 1, 2012, reflected the estimated extended end-of-life dates shown above. For Pickering Units 5-8, these lives were based on an assumption that OPG would achieve high confidence that the units. would operate to 240,000 Equivalent Full Power Hours ("EFPH"). As noted in the response to part c) below, OPG's Depreciation Review Committee ("DRC") is now satisfied that there is a high confidence level of achieving 247,000 EFPH at Pickering Units 5-8**.**

c) OPG's Board of Directors ("OPG Board") approved the reference Darlington Refurbishment start date of October 2016 in November 2009 with the expectation that the schedule would be subject to refinements as technical studies and regulatory work programs are completed, risks assessed, and detailed schedules and cost estimates are developed. The final refurbishment schedule and unit start dates will be confirmed as part of the OPG Board's approval of a Release Quality Estimate in 2015. As such, the estimated average end-of-life date, for accounting purposes, of the Darlington station at the time of filing of this application is December 31, 2051, which is the same as that approved by the OEB in EB-2010-0008 and remains management's current assessment.

The estimated average end-of-life dates of the Pickering stations, for accounting purposes, at the time this application was filed are also the same as those approved by the OEB in EB-2010-0008, i.e., estimated average end-of-life dates of December 31, 2021 for Pickering Units 1 and 4 and of September 30, 2014 for Pickering Units 5-8.

In EB-2010-0008, the approved DRC recommendation was for the lives of the Pickering stations to remain unchanged until a substantial body of technical work was completed, which would allow OPG to be satisfied that there is a high confidence level associated with achieving extended lives for Pickering Units 5-8 pressure tubes. At the time of filing this application on September 24, 2012, OPG was in the process of reviewing the results of this technical work.

The DRC is now satisfied that there is a high confidence level associated with continued operations (i.e., achieving 247,000 EFPH at Pickering Units 5-8). Effective December 31, 2012, the revised estimated end-of-life dates, recommended by the DRC for accounting purposes, for Pickering Units 5-8 are as follows:

Unit 5	Q1 2020
Unit 6	Q2 2019
Unit 7	Q4 2020
Unit 8	Q4 2020

The resulting average end-of-life dates recommended by the DRC, for accounting purposes, for Pickering Units 5-8 is April 30, 2020. The revised estimated average end of life dates recommended by the DRC for Pickering Units 1 and 4 is December 31, 2020.

c) Attachments 1 and 2 provide the requested documents for 2010 and 2011, respectively.

2010 REPORT

DEPRECIATION REVIEW COMMITTEE

For

Regulated Business

March 2011

Regulated – 2010 Depreciation Review Committee Report

EXECUTIVE SUMMARY

Background

The Depreciation Review Committee (DRC) is convened annually to review the service lives for depreciation purposes of major facilities and a selection of asset classes with the objective of reviewing the majority of asset classes over a five year period. The DRC's recommendations are documented in separate reports signed by senior executives for the regulated and unregulated business, which form the basis for depreciation expense that is recorded in OPG's audited financial statements. Any DRC recommendations with respect to changes to station and/or asset class service lives for depreciation purposes require a high degree of confidence in order to meet accounting guidelines and to satisfy OPG's external auditors.

Scope of 2010 Review

The scope of each year's review is driven by generally accepted accounting principles (GAAP), OEB requirements and the specific issues that each of the lines of business are facing.

Nuclear

At the end of 2009, the DRC has reviewed the majority of nuclear asset classes. The main focus of this year's review was to confirm whether their forecast lives could support the extended operating life of Darlington based on current condition assessments at Darlington (see Appendix C for asset classes selected for review). In addition, a sample of assets totaling approximately $65 million that had not been reviewed by the DRC in the current five year cycle was selected. As indicated in Appendix C, these included Minor Fixed Assets (MFA) and the Nuclear Training Simulator (asset class #16310000). At the end of the 2010 review, the DRC estimates that approximately 6% of nuclear fixed assets have not been reviewed as part of the current five year cycle. However, these remaining items are primarily lower dollar items such as MFAs and any change to service lives would not have a material on depreciation expense.

Hydroelectric

At the completion of the 2009 review, the DRC had reviewed all hydroelectric asset classes. In the current year, the DRC started a new review cycle and selected those asset classes that had been reviewed in 2006. Appendix D lists the asset classes that were reviewed in 2010 which represent coverage of approximately 39% of the total hydroelectric regulated asset base.

Recommendations from the 2010 Review

Based on the 2010 review of nuclear station lives and asset classes, the DRC recommends the following:

1. The average end-of-service life for depreciation purposes of Bruce A should be extended from 2035 to 2037. This will result in a decrease to annual depreciation expense of approximately $2 million.

2. The average end-of-service lives for depreciation purposes of the remaining nuclear stations remain unchanged as follows:

   a. Pickering A – December 31, 2021
   b. Pickering B – September 30, 2014
   c. Darlington – December 31, 2051
   d. Bruce B – December 31, 2014

3. The service life for nuclear asset class #15600000 (Instrumentation and Control) should be reduced from 30 years to 15 years. This will result in an increase to annual depreciation expense of approximately $6 million.

Based on the 2010 review of hydroelectric asset classes, the DRC recommends the following:

> Fire protection systems for Regulated Hydroelectric stations should be removed from asset class #10700000 (Auxiliary Systems) and set up as a new asset class with a service life revised from 30 to 20 years. This will result in an increase to annual depreciation expense of approximately $1 million.

The DRC recommends that the above changes be implemented with an effective date of January 1, 2011 which will result in an annual increase to depreciation expense of approximately $5 million, commencing in 2011.

Regulated – 2010 Depreciation Review Committee Report

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1.0 INTRODUCTION

1.1 Work of the Depreciation Review Committee

The Depreciation Review Committee (DRC) is convened annually to review the service lives for depreciation purposes of major facilities and a selection of asset classes in those facilities with the objective of reviewing all significant asset classes over a five year period. The selection of asset classes to be reviewed and the approach to be taken to the review of the classes and major facilities are approved by OPG's senior executives (the Approval Committee). On completion of each annual review, the DRC documents its findings in a report, including the financial impact of any recommended changes to asset service lives for depreciation purposes and submits these recommendations for approval to the Approval Committee. The approved recommendations are used to estimate the depreciation expense that is recorded in OPG's consolidated financial statements. The approved DRC report impacts the depreciation expense forecast used for business planning purposes and is therefore also included in the periodic payment amount applications submitted to the Ontario Energy Board.

Since the main purpose of the DRC review is to support depreciation expense to be reported in OPG's consolidated financial statements, the DRC is led by staff members from Corporate Finance. In order to properly assess the service lives for depreciation purposes of major facilities and selected asset classes, the DRC seeks engineering and technical input when conducting its annual review. As such, the DRC has the support of representatives from the various lines of business who have substantial knowledge and expertise in the operations of the generating stations operated by OPG. This support is provided by senior management for each line of business who appoint the appropriate technical and engineering staff to assist the DRC in their review. Appendix A provides the listing of DRC members and supporting business unit representatives.

1.2 Review Scope

In order to achieve sufficient support for recorded depreciation in OPG's consolidated financial statements, the DRC focuses on the review of both station end-of-service life dates and asset classes for Nuclear and on asset classes for Hydroelectric. Station service lives for Hydroelectric are not typically reviewed by the DRC as such facilities tend to have long service lives that exceed asset class life. Nuclear facilities on the other hand have shorter service lives that could potentially limit asset class lives.

2.0 Review of Nuclear Assets

Principles for Changing Asset Service Lives

For financial accounting purposes, recommended changes to existing station end-of-life dates and asset class service lives require a high degree of confidence in order for any changes to be considered for recommendation by the DRC. OPG's senior management and internal and external auditors must also be satisfied with the underlying support for the recommendations for any such changes.

Scope

The DRC's deliberations for 2010 continued with its focus both on the review of station service life for depreciation purposes and asset class service life.

Particular focus was on new data available for Darlington asset classes to ensure whether these service lives could be extended to the end of the post-refurbishment period (see Appendix C for asset classes selected for review).

In addition, a sample of minor fixed assets (MFAs) was also selected for review as these assets have not yet been covered in the current five year cycle.

Asset Class Coverage

At the end of 2010, the DRC has reviewed approximately 94% of nuclear assets. In this year's review, the DRC reviewed approximately $65 million of assets that had not yet been covered in the five year review cycle, including the Nuclear Training Simulator as well as a selection of MFAs (see Appendix C for details). Since the remaining asset classes that have not been reviewed are low dollar items such as MFAs, any potential changes to the service lives of these assets would not have a material impact on depreciation expense and as such, the DRC has completed its coverage of significant nuclear asset classes.

2.0.1 Pickering and Darlington

Pickering B

The primary determinant of end-of-service life date for depreciation purposes of the Pickering B units is the expected lives of the pressure tubes. The current nominal life expectation on the pressure tubes at Pickering B results in an average station end-of-service life for depreciation purposes of September 30, 2014.

As discussed in last year's report, OPG has embarked on a work program (including physical work in the plant, laboratory tests, analytical work and discussions with the nuclear safety regulator) to demonstrate high confidence in extended service lives of the Pickering B pressure tubes. If successful, OPG would expect to be able to operate the Pickering B units until 2018 to 2020. This scenario is known as the "Continued Operations" scenario.

The work to gain high confidence in extended service lives of the pressure tubes is not expected to be complete until the latter part of 2012. Successful completion of the work to gain high confidence faces challenges on several fronts, and OPG is working to resolve and mitigate the risks on all of these fronts. Bruce Power and AECL have joined with OPG and are sharing the costs of the project to achieve higher confidence in longer pressure tube lives. OPG also recognizes that ultimate achievement of high confidence for accounting purposes must be informed by any potential risks associated with market conditions and their implications on the economic viability of the continued operations scenario.

Given these considerations, the DRC recommends that the average end-of-service life date for depreciation purposes of Pickering B (that being the average of the 4 generating unit end of life dates) should remain unchanged at September 30, 2014, until there is a high degree of confidence associated with the achievement of continued operations.

At the end of the 2009 review, the majority of asset classes for Pickering B had been reviewed by the DRC in the five year cycle which commenced in 2006. Thus, no additional asset classes were selected in the current year review.

Pickering A

As discussed in the 2009 report, the DRC recommends that the average service-life-date for depreciation purposes for the two units at Pickering A remain unchanged at December 31, 2021.

The DRC recognizes that there are significant technical and regulatory risks which would make it difficult to operate Pickering A Units 1 and 4 as standalone units after the last two units of Pickering B have reached their end of life. Moreover, should the Pickering B units be permanently shut down, there is a high probability that Pickering A would prove uneconomical to operate without the Pickering B units in operation.

However, there has been no additional information brought forward in 2010 to change the recommendation in the 2009 DRC report regarding the end-of-service-life date for depreciation purposes of Pickering A. As such, OPG cannot claim high confidence to support a change in this date to align with the Pickering B date, until there is greater certainty around the Pickering B service lives. Recommending any change at this point would be premature and could lead to successive end of life date changes over a short period of time.

At the end of the 2009 review, the majority of asset classes for Pickering A had been reviewed by the DRC in the five year cycle which commenced in 2006. Thus, no additional asset classes were selected in the current year review.

Darlington

As discussed in the 2009 review, the DRC changed the average station end-of-life date for depreciation purposes of the four units at Darlington to December 31, 2051 as of January 1, 2010, in order to reflect OPG's Board of Directors' approval and the Shareholder's concurrence of management's recommendation to proceed to the definition phase of the Darlington refurbishment project. The date established for depreciation purposes was based on:

a) High confidence that the Darlington refurbishment project would be executed and the units returned to service.
b) The current expectation that the post-refurbishment service life of each unit will be nominally 30 years.
c) OPG's assessment that there is low risk, based on similar refurbishment projects already underway and well-established technical and regulatory processes for refurbishment, that the execution of the refurbishment would not be completed.

In the 2009 DRC review, a detailed asset class review had also been conducted resulting in changes to the service lives of various asset classes for Darlington.

In the 2010 DRC review, the main focus was on a sample of the asset classes that were reviewed in 2009 with an objective to confirm whether their forecast lives could support the extended operating life of Darlington based on current condition assessments at Darlington. As indicated in Appendix C, a selection of asset classes was made by the DRC based on materiality and reviewed by nuclear technical staff.

The review included Buildings and Structures, Process Systems, Turbine and Auxiliary Equipment and Instrumentation and Control. This review relied on current condition assessments at Darlington and indicated the following:

- For Buildings and Structures, Process Systems and Turbine Auxiliary Equipment asset classes, all components and systems are expected to be able to support the extended life of Darlington, assuming normal maintenance is performed. This is consistent with the DRC recommendations in 2009.

- For the Instrumentation and Control asset class, components included computer control equipment, reactor measuring, control and protective systems, control and protective relaying systems and public address systems. In engineering's view, these types of components have not demonstrated that they will achieve the current asset class life of 30 years. Current lifecycle plans and replacement programs suggest 15 years as an approximate period for newly installed components. As such, a service life of 15 years is recommended. This revised life would be applicable to the total asset class.

2.0.2 Bruce

Bruce A

As discussed in the 2009 report, the average station end-of-life date for depreciation purposes for Bruce A was determined based on: i) an agreement between Bruce Power L.P and the Ontario Power Authority signed in October 2005 that Bruce A Units 1, 2 & 3 will be refurbished to extend their lives; and ii) an amendment to that agreement in August 2007 that Bruce Unit 4 will also be refurbished. The expected return to service for Units 1 and 2 used in the 2009 DRC report was 2011, followed by operation for nominally 25 years. Since the refurbishment dates for Units 3 and 4 had not yet finalized, the DRC assumed the same end-of-life dates as Units 1 and 2 pending additional information. This had resulted in a nominal 2035 as the average station end-of-life date for depreciation purposes, which was the same date that was established in the 2007 DRC review.

During the 2010 review, the DRC received confirmation that there has been a delay to 2012 in the expected return-to-service dates of Units 1 and 2. As Bruce Power's stated intention is to operate these units for 25 years, this would result in an end-of-life date of 2037 for these units.

For Units 3 and 4, more recent publicly available information in February 2011 suggests that Bruce Power may operate these units until 2021, after which time the plan is that they will be refurbished. Based on the facts available, the DRC believes there is currently no higher degree of confidence that Units 3 and 4 will be able to operate to an extended date of 2021, than there currently is for the Pickering B units. As for Pickering B, operating to these extended end-of-life dates requires a successful outcome of the work to gain high confidence in extended pressure tube lives. The following was considered for this assessment:

- There has been no additional technical information brought forward in 2010 to suggest that the units will operate for an extended period to 2021 beyond the current expected nominal life dates to provide a high degree of confidence similar to the discussions relating to Pickering B and Bruce B (see sections 2.0.1 for Pickering B and 2.0.2 for Bruce B).
- Recommending any changes to extend the end-of-life date up to the 2021 expected refurbishment date for Units 3 and 4 beyond the current high confidence pressure tube life, could result in successive end-of-life date changes over a short period of time.

Based on the above, the DRC recommends that average end-of-life date for the Bruce A station for depreciation purposes be extended to 2037 from 2035, primarily as a result in the delayed return of Bruce Units 1 and 2.

Bruce B

As discussed in the 2009 report, the service lives of the Bruce B units are limited by the expected service lives of the pressure tubes. The current high confidence expectation of the service lives of the pressure tubes results in OPG's prediction of December 31, 2014 as the average end-of-life date for depreciation purposes for Bruce B. Bruce Power has indicated a desire to operate the Bruce B units longer, and has signed on to the project with OPG, aimed at increasing the confidence in predictions of longer service lives of the pressure tubes by 2012. At this time, OPG's assessment (similar to the assessment for Pickering B) is that the confidence level in achieving additional service life from the Bruce B units is not sufficiently high to allow a change in the average end-of-service life date, for depreciation purposes.

In addition, although there are indications in documents published by the Ontario Power Authority that refurbishment of the Bruce B units may be part of Ontario's Long term Energy Plan, there have been no formally announced plans by Bruce Power to refurbish the Bruce B units.

Based on the above considerations, the DRC recommends that the average end-of-life date for depreciation purposes of the four units at Bruce B should remain unchanged at December 31, 2014.

2.0.3 Additional Asset Classes Reviewed

Also included in the DRC's asset class selection for 2010 were assets that have not yet been covered in the five year reporting cycle. These assets totaled $65 million in NBV and as indicated in Appendix C included MFAs and the Nuclear Training Simulator (asset class #16310000). Based on the review of these assets, the service lives were found to be reasonable with no change recommended.

2.1.0 DRC Recommendations – Nuclear

Based on the 2010 review of average station-end-of service life dates for depreciation purposes and of the service lives of nuclear asset classes, the DRC recommends the following:

- The average end-of-service life for depreciation purposes of Bruce A should be extended from 2035 to 2037. This will result in a decrease to annual depreciation expense of approximately $2 million.

- The average service lives for depreciation purposes of Pickering A and B, Darlington and Bruce B stations remain unchanged as noted in sections 2.0.1 and 2.0.2.

- The service life for nuclear asset class #15600000 (Instrumentation and Control) should be reduced from 30 years to 15 years. This will result in an increase to annual depreciation expense of approximately $6 million.

2.2.0 Summary of Nuclear Stations' Average End of Service Life Dates for Depreciation Purposes

Station	Current End of Life Date (Dec. 31, unless otherwise stated)
Pickering A Units1 and 4	2021
Pickering A Units 2 & 3*	n/a
Pickering B	2014***
Darlington	2051
Bruce A**	2037
Bruce B**	2014

* Assets written off in 2005 as a result of the decision not to proceed with the return to service of the units.
** Assets are on lease to Bruce Power for an initial term of approximately 17 years (commenced May 1, 2001).
***End of life occurs on September 30, 2014.

3.0 Review of Regulated Hydroelectric Assets

3.0.1 Overview

Hydroelectric facilities have six regulated stations within two plant groups (Sir Adam Beck One, Sir Adam Beck Two, Sir Adam Beck Pump Generating Station, DeCew Falls One, and DeCew Falls Two, within the Niagara Plant Group, and R.H. Saunders within the Ottawa-St. Lawrence Plant Group). OPG has 27 dams that are associated with the Niagara Plant Group stations and three dams that are associated with the R.H. Saunders Generating Station.

Each year the DRC reviews the service lives of a selection of asset classes from hydroelectric facilities. Asset class reviews are conducted by experienced engineers who have detailed working knowledge of the operations at the stations. The engineers who perform the reviews use various sources of information including lifecycle planning data, site condition assessments and comparative data obtained from other utilities. Over the years, asset class reviews have indicated that hydroelectric assets are generally long-lived with a very mature technology. For the most part, dramatic changes or advances in technology are extremely unlikely.

As mentioned, the review of asset classes considers a general review of comparable data with other utilities. This data has been obtained over the years by engineering staff through their industry contacts. Since OPG hydroelectric facilities have similar technology to other utilities, when conducting asset class reviews, engineering staff do compare asset class service lives with those available from other utilities. Some of the utilities where comparative data is available include Manitoba Hydro, BC Hydro and Trans Alta.

3.0.2 Regulated Hydroelectric Asset Class Review

In the current year, the DRC has begun a new review cycle and has selected asset classes that have already been reviewed in 2006. Appendix D lists the asset classes that were reviewed in 2010.

With the exception of one asset class (#10700000 Auxiliary Systems), internal assessments indicated that the service lives of the other asset classes reviewed were reasonable. In addition, the service lives of these asset classes were generally consistent with the comparative data from other utilities. As such, no change to the service lives of these classes has been recommended.

With regards to the review of asset class #10700000 Auxiliary Systems, this class includes a variety of assets including fire protection systems, lighting installation, heating equipment, ventilating equipment, water systems and auxiliary power equipment. As a result of finding some corrosion/silt in recent inspections of the fire protection systems, the expected life has been shortened. Also, technological advances in detection, alarm and suppression equipment has resulted in the need for periodic replacement. Based on these findings, a reduction in the life of fire protection systems from 30 to 20 years has been suggested by engineering.

Since there was no evidence to suggest that the other assets in the class would warrant the recommended change in life, the preferred option would be to remove the fire protection equipment from the current class and transfer into a separate asset class with a 20 year life.

3.1.0 DRC Recommendations

Based on the evidence submitted by hydroelectric engineering staff concerning the asset classes reviewed, the DRC recommends the following with respect to the average asset service lives:

1. There should be no change to the service lives for the following asset classes:
   - 10200000 Sub and Super Structures
   - 10301000 Tunnel Linings
   - 10318000 Gates and Operating Mechanisms
   - 10501000 Main Rotating Equipment
   - 10510000 Main Power and Station Service

2. With regards to Auxiliary Systems, fire protection equipment should be removed from this asset class and transferred to a new asset class with a 20 year service life. This will result in an increase to annual depreciation expense of approximately $1 million.

APPENDIX A

THE DEPRECIATION REVIEW COMMITTEE

The DRC includes representatives from each operating business unit, as nominated by the business unit representatives of the Approval Committee, as well as representatives having experience in finance, investment planning and rate regulation.

Representatives on the DRC are listed below.

DRC members

Nathan Reeve - Vice President, Financial Services
Dave Bell – Manager, Corporate Accounting
John Tipold - Senior Financial Analyst, Corporate Accounting
John Mauti - Director, Nuclear Finance
Alex Kogan - Manager, Regulatory Finance
Randy Pugh – Director, Ontario Regulatory Affairs
Eleen Louie – Manager, Corporate Financial Processing Services
Stephen Rogers – Director, Asset Planning & Integration, Corp. Inv. & Asset. Planning

Business Unit Representatives:

Hydroelectric
Don Brazier – Director of Finance, Hydro
Mark Del Frari – Senior Advisor, Finance, Hydro
Gord Haines – Manager, Electrical Dept
Jim Wagner – Section Manager, Civil Engineering Dept
Bruce Hogg – Section Manager, Mechanical Equipment
Don Haber – Manager Power Equipment
Stefano Bomben – Senior Engineer, Hydro Generators
Enos Candido – Senior Engineer, Hydro Mechanical Eng

Nuclear
Terry Karaim – Director of Engineering – Darlington Refurbishment
Paul Spekkens – Vice President – Science & Technology
Dave Vermey – Senior Technical Expert – Plant Computers – Engineering & Modifications

APPENDIX B

ONTARIO POWER GENERATION'S FIXED ASSETS

Ontario Power Generation categorizes its fixed assets as follows:

- major fixed assets under construction;
- major fixed assets in service; and
- minor fixed assets

Major fixed assets under construction are comprised of land, buildings, plant, and equipment in the process of being acquired or constructed. The ultimate economic benefit of acquiring and constructing these assets is considered to relate to future periods.

Major fixed assets in-service consist of land, buildings, plant and equipment that have been declared in-service.

Minor fixed assets are comprised of transport and work equipment, service equipment, office furniture and equipment, computers other than those directly supporting the bulk electricity system and railway equipment. These assets are accounted for on a more detailed unit basis for control reasons.

OPG maintains accounting records of the costs of its fixed assets. Their accumulated depreciation and retirements provide a history of the assets constructed or acquired by OPG. Consistent with the other major electrical utilities in North America, OPG maintains its fixed asset accounting records on the basis of asset classes.

APPENDIX C - NUCLEAR ASSET CLASSES REVIEWED IN 2010 ($M)

Class #	Description	YE 2010 NBV ($M)	Current Life (Years)	Prior Review Year	Revised Life
15200000	Buildings & Structures (Note 1)	94	55	2009	No
15340000	Process Systems (Note 1)	23	55	2009	No
15400000	Turbine Auxiliary Equipment (Note 1)	2	55	2009	No
15600000	Instrumentation and Control (Note 2)	174	30	2009	15
16310000	Nuclear Training Simulator	32	45	No	No
MFAs	(Note 3)	33	various	No	No
	Totals	**358**			

Note 1
Asset class values represent Darlington's portion only.

Note 2
The NBV represents the total asset class value.

Note 3
The specific MFA items that were reviewed in 2010 by the DRC are as follows:

Asset	$M NBV
UDM's – Service Equipment	13
Darlington Feeder Integrity – Service Equipment	8
Feeder Cut & Weld Tooling – Service Equipment	7
Transport & Work Equipment	5
Total MFA reviewed in 2010	33

Summary:

This year's DRC focused on a review of certain asset classes that were reviewed last year as well as a selection of assets that have not been reviewed in the five year cycle.

Based on the review the service lives of asset classes from the previous year, all were found to be reasonable except for asset class #15600000 (Instrumentation and Control). The service life for this asset class has been reduced from 30 years to 15 years which will result in an increase to annual depreciation of approximately $6 million.

Based on the review of assets that were not covered in previous DRC's, the service lives were found to be reasonable. As a result of the review of these assets not covered in previous DRC's ($65 million in NBV), the total of assets that have not yet been reviewed by the DRC at the end of 2010 is approximately $220 million (approximately 6% of Nuclear's NBV total of $3,963 million based on year end 2010 NBV's). The assets that have not been reviewed by the DRC are primarily lower dollar items such as MFA (approximately 3% of Nuclear NBV) that would not have a material impact on depreciation expense should their service lives change.

APPENDIX D – HYDROELECTRIC REGULATED ASSET CLASSES REVIEWED IN 2010 ($M)

Class #	Description	Y/E 2010 NBV ($M)	Current Life (Years)	Prior Review Year	Revised Life
10200000	Sub and Super Structures	802	100	2006	No change
10301000	Tunnel Linings	227	75	2006	No change
10318000	Gates and Operating Mechanisms	151	50	2006	No change
10501000	Main Rotating Equipment	124	75	2006	No change
10510000	Main Power and Station Service	78	50	2006	No change
10700000	Auxiliary Systems (Note 1)	62	30	2006	No change
	Totals (Note 2)	**1,444**			

Note 1
This asset class comprises a variety of assets including fire protection equipment, lighting installation, heating and ventilating equipment, water systems and auxiliary power systems. The 2010 review indicated that fire protection system assets should have a 20 year life. The DRC has recommends that these assets be removed from the current class and transferred to a new class with a 20 year life. This will result in an increase to annual depreciation expense of approximately $1 million.

Note 2
At the end of 2009, the DRC has reviewed the majority of asset classes and is beginning a new review cycle in this year's review. Asset classes reviewed in 2010 represents approximately 39% of total hydroelectric regulated fixed assets based on year end 2010 NBV's.

ONTARIO POWER GENERATION

February 2012

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM

2011 Depreciation Review Recommendations – Regulated Business

This memorandum seeks approval of recommendations resulting from the 2011 review of the average service lives of nuclear and regulated hydroelectric fixed and intangible asset classes and the average end-of-life dates for the nuclear stations for depreciation purposes.

BACKGROUND

In 2011, an external consultant, Gannett Fleming Inc. ("Gannett Fleming"), was engaged to review the estimated average services lives of asset classes and the average station end-of-life dates of the prescribed facilities of Ontario Power Generation Inc. ("OPG") and provided their findings in a separate report to be filed as part of the evidence submission for OPG's next application to the Ontario Energy Board ("OEB") for new payment amounts. OPG was directed to conduct this independent depreciation study by the OEB in its Decision with Reasons dated March 10, 2011 on OPG's last application for payment amounts (file no. EB-2010-0008). Gannett Fleming issued their report, titled "Assessment of Regulated Asset Depreciation Rates and Generating Station Lives," in December 2011.

Gannett Fleming reviewed all fixed and intangible asset classes and station end-of-life dates of the prescribed facilities. OPG staff from Finance and Regulatory Affairs as well as representatives from the lines of business, including technical and engineering staff, were engaged throughout the review process and have concurred with its results. These results are reflected in the recommendations being submitted to the Approval Committee in this memorandum.

In 2012, OPG's Depreciation Review Committee ("DRC") is expected to begin a new cycle with the objective of reviewing all significant asset classes for the regulated business over a five year period.

The prescribed facilities for which average service lives were analyzed by Gannett Fleming are as follows:

- Sir Adam Beck I and II Hydroelectric Generating Stations
- Sir Adam Beck Pump Generating Station
- DeCew Falls I and II Hydroelectric Generating Stations
- R.H. Saunders Hydroelectric Generating Station
- Pickering Nuclear Generating Station (Pickering A and B)
- Darlington Nuclear Generating Station

This memorandum also seeks approval of recommendations relating to the average station end-of-life dates of the Bruce A and B Nuclear Generating Stations.

SUMMARY OF RECOMMENDATIONS

Prescribed Facilities

It is recommended to adopt the findings of Gannett Fleming that, with the exceptions noted below, OPG continue the use of the existing average service lives for all fixed and intangible asset classes of the prescribed facilities and the existing average station end-of-life dates for the prescribed nuclear facilities.

Specifically with respect to Pickering average station end-of-life dates, Gannett Fleming noted in their report that it would be premature to change the end-of-life dates of the Pickering A and Pickering B generating

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stations until such time that the work program necessary to determine the economic feasibility of achieving extended service lives of pressured tubes at Pickering B has been completed. This conclusion is consistent with previous years' approved recommendations of the DRC that the end-of-life date of Pickering B should remain unchanged for depreciation purposes until there is a high degree of confidence associated with the achievement of continued operations at the station and that the end-of-life date of Pickering A for depreciation purposes should remain unchanged until there is greater certainty around the Pickering B service life.

It is therefore recommended that the average station end-of-life dates for the prescribed nuclear facilities remain unchanged as follows:

Station	Average Station End-of-Life Date
Pickering A	December 31, 2021 *(unchanged)*
Pickering B	September 30, 2014 *(unchanged)*
Darlington	December 31, 2051 *(unchanged)*

Gannett Fleming recommended the following changes for the average service lives of the asset classes of the prescribed facilities, which are recommended to be implemented effective January 1, 2012:

1. The average service life of asset class #10400000 (Hydroelectric Turbines and Governors) should be reduced from 75 years to 70 years.
2. The average service life of asset class #10210000 (Hydroelectric Service and Equipment Buildings) should be increased from 50 to 55 years.
3. A new asset class with an average service life of ten years should be established for hydroelectric security systems, which had previously been included in a broader class with a 30-year average service life.

The above changes to the average service lives of asset classes will result in an increase in the annual depreciation expense of approximately $1 million for the prescribed facilities.

The methods used by Gannett Fleming in their review and the specific rationale supporting the above changes are found in their report.

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Bruce Nuclear Generating Stations

The recommended average station end-of-life dates for the Bruce stations effective January 1, 2012 discussed below are as follows:

Station	Average Station End-of-Life Date
Bruce A	December 31, 2042 *(extended from December 31, 2037)*
Bruce B	December 31, 2014 *(unchanged)*

Bruce A

The expected return-to-service dates for Bruce A Units 1 and 2 are in the middle to the latter part of 2012 based on publicly available information. At the currently assumed nominal operating life of 30 calendar years for the replaced pressure tubes, which is consistent with other CANDU plants and OPG's technical, operational and industry experience, these units would be expected to reach their end of life in approximately 2042.

Bruce A Units 3 and 4 are currently operating with their original pressure tubes. Based on the agreement between the Ontario Power Authority and Bruce Power the target for these units is to operate until the early 2020s prior to their refurbishment that would replace the original pressure tubes. The operation of Units 3 and 4 until the early part of the 2020s would require the existing pressure tubes to operate beyond their current nominal design life.

As noted in previous years' approved DRC recommendations, Bruce Power has signed on to the project with OPG aimed at increasing the confidence in extended service lives of the pressure tubes by the end of 2012. As indicated above, OPG currently does not have the requisite high confidence that the extended life for the pressure tubes will be achieved for the Pickering B units, as the work program to obtain such confidence is currently ongoing. Thus, it remains premature to conclude, for depreciation purposes, with the requisite confidence that Bruce A Units 3 and 4 will be able to achieve an extended life for the pressure tubes and operate until the early 2020s prior to refurbishment. This conclusion is consistent with approved 2010 DRC recommendations.

Therefore, effective January 1, 2012, the overall Bruce A average station end-of-life date for depreciation purposes is recommended to be extended to December 31, 2042 based on the expected end-of-life dates for Bruce A Units 1 and 2. This represents an increase in the life of five years from December 31, 2037 and reflects an expected 30-year post-refurbishment operating period for Units 1 and 2. Since the refurbishment dates for Units 3 and 4 have not been finalized, this recommendation assumes the same end-of-life dates for Units 3 and 4 as for Units 1 and 2 pending additional information. This approach for Units 3 and 4 is consistent with the approved DRC recommendations of previous years.

The extension of the Bruce A average service life to December 31, 2042 will result in a decrease in depreciation expense of approximately $5 million annually excluding the impact of the adjustment to the nuclear asset retirement obligation recorded on December 31, 2011.

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Bruce B

As noted in the previous years' approved recommendations of the DRC, the service lives of the Bruce B units are limited by the expected service lives of the pressure tubes. The current high confidence expectation of the service lives of the pressure tubes of the Bruce B units continues to result in December 31, 2014 as the average end-of-life date for the Bruce B station for depreciation purposes. Bruce Power has indicated a desire to operate the Bruce B units longer, and, as noted above, has signed on to the project with OPG regarding extended pressure tube lives. However, similar to the assessment for Bruce A Units 3 and 4 and Pickering B, OPG's assessment continues to be that the confidence level of achieving a longer service life for the Bruce B units is not sufficiently high to allow a change in the average station end-of-life date at this time. As such, it is recommended that the average station end-of-life date for Bruce B remain as December 31, 2014.

Board Staff Interrogatory #20

Ref: Exh H2-1-1 pages 2 and 3

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

Interrogatory

The pre-filed evidence states that one of the main steps in establishing a new ONFA Reference Plan is, "Developing cost estimates for each of the five nuclear waste management and decommissioning programs based on the planning assumptions … The baseline cost estimates are escalated into future year values and then discounted to today's dollars using the approved discount rate established in the ONFA (5.15 per cent for the current approved ONFA Reference Plan) in order to calculate the present value of the lifecycle liability." The evidence also states that an accounting consequence of the current approved ONFA Reference Plan is, "A 2011 year-end net increase to the carrying book value of the ARO and ARC of $934M at a discount rate of 3.43 per cent."

a) Please clarify the differences in using two discount rates referenced above in relation to the baseline cost estimates of 5.15 per cent and the carrying book value of the ARO and ARC of 3.43 per cent.

b) Do USGAAP and IFRS permit the use of a different discount rate which is applied only to the portion of the ARO that has changed due to amendments to the ARO?

Response

a) As described in interrogatory L-2-1 Staff-18, the discount rate used to derive the present value of the ONFA lifecycle liability is determined in accordance with the provisions of the ONFA (5.15 per cent for the 2012 ONFA Reference Plan). When there is an increase in the undiscounted cash flows, in accordance with CGAAP and USGAAP, the discount rate (i.e., the accounting accretion rate) used to derive changes to OPG's ARO and ARC is the credit-adjusted risk-free rate determined at the time of the increase (3.43 per cent for the 2011 year-end ARO increase).

b) Consistent with Canadian GAAP, under USGAAP, each new tranche representing the present value of an increase in the estimated undiscounted cash flows of the ARO is derived using the rate determined at the time of the increase. The existing ARO remains at historical rates used to measure the existing tranches when they were originally recorded. This treatment is not permitted under IFRS, which would require OPG to re-measure the entire ARO using a single discount rate determined at the time of the increase.

Board Staff Interrogatory #21

Ref: Exh H1-1-1 Table 5
Exh H2-1-3 Attachment 1 page 5

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

Interrogatory

Table 5 summarizes the approved Forecast Pension and OPEB Costs (EB-2010-0008) for 2011 and 2012 in lines 1 and 2. Note 2 to Table 5 shows the calculation of the forecast for the two years derived by dividing the total two-year forecast by 24 months in order to pro-rate the amounts shown in Table 5 column (a) and (b) for 2011 and (d) and (e) for 2012. In the *Independent Auditors' Report, Schedule of the Pension and OPEB Cost Variance Account as at December 31, 2011*, Note 2 specifies that the actual pension and OPEB costs for the ten-month period ended December 31, 2011 were determined by applying a factor of 10/12 to the actual pension and OPEB costs attributed to the Prescribed Facilities for the year ended December 31, 2011.

a) Please recalculate the forecast amounts in Note 2 lines 4a and 5a under columns (a) and (b) for 2011 and (d) and (e) for 2012 respectively in relation to Table 5 lines 1 and 2 as follows:
i. In line 4a, using the 2011 Forecast Pension Cost (EB-2010-0008) amounts shown in line 1a, divide these amounts by 12 times 10 (i.e., ((line 1a / 12) x 10 months))
ii. In line 5a, using the 2012 forecast - unadjusted (EB-2010-0008) amounts shown in line 2a, divide these amounts by 12 times 12 (i.e., ((line 2a / 12) x 12 months))

b) Please recast Table 5 and Note 2 and all other applicable tables based on the above recalculation of the Pension and OPEB Variance Account balances as at December 31, 2011 and December 31, 2012.

Response

a) and b)

Using the approach suggested in the question is not appropriate for three reasons.

First, in contrast to the approach used by OPG, the suggested approach does not accurately reflect amounts that are being recovered through the current payment amounts and, therefore, does not result in accurate account balances. The current payment amounts were established by using a combined 24-month 2011-12 revenue requirement but became effective on March 1, 2011. In effect, OPG is recovering 22/24 of the two-year 2011/2012 forecast. The calculations in pre-filed Ex. H1-1-1 Tables 5 and 5a reflect this correctly. In contrast, the approach suggested in the question would incorrectly consider 10/12 of the full-year 2011 forecast and 12/12 of the full-year 2012 forecast.

Second, as required by the Decision with Reasons in EB-2011-0090, the 2011 ending balances in the Pension and OPEB Cost Variance Account as submitted by OPG have been audited by Ernst & Young LLP and were found to be presented “fairly, in all material respects” (Ex. H2-1-3 Attachment 1, page 1, para. “Opinion”).

Third, in calculating account additions for 2011 and 2012, OPG has consistently used the same standard approach for this and all other applicable accounts for the reasons given above. The application of the standard approach is described at Ex. H1-1-1, page 3, lines 18-22.

Despite the issues with the suggested approach identified above, the affected tables noted below have been recast as requested and are attached.

Table as Filed	Recast Table Attached
Ex. H1-1-1 Table 1	Table 1
Ex. H1-1-1 Table 1b	Table 2
Ex. H1-1-1 Table 1c	Table 3
Ex. H1-1-1 Table 5	Table 4
Ex. H1-1-1 Table 5a	Table 5
Ex. H1-2-1 Table 1	Table 6
Ex. H1-2-1 Table 2	Table 7
Ex. I1-1-2 Table 1	Table 8

Please note that in order to ensure the integrity of the calculation of the balance in the account, the forecast regulatory income tax impact amounts calculated in Note 1 to Ex. H1-1-1 Table 5a have also been recast using 10/12 of 2011 and 12/12 of 2012 forecast amounts. Carrying charges were also recalculated accordingly.

Numbers may not add due to rounding.

Table 1
(Recast of 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	Projected Year End Balance 2012
		(a)	(b)	(c)	(d)
	Regulated Hydroelectric:				
1	**Hydroelectric Water Conditions Variance**	(55.3)	(70.2)	(41.4)	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(16.0)	(9.4)	10.6	32.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	(1.4)	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.5	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(0.3)	(8.1)	(6.8)	(2.6)
6	**Tax Loss Variance - Hydroelectric**	47.1	78.8	68.0	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	0.0	(0.7)	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	5.4	16.5
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	2.7
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.2)	(2.3)	(1.2)	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	0.0	(7.9)	(5.9)	(3.4)
12	**Total**	(26.6)	(19.1)	27.0	108.9
	Nuclear:				
13	**Pickering A Return To Service (PARTS) Deferral**	81.8	33.2	0.0	0.0
14	**Nuclear Liability Deferral**	86.2	39.2	21.8	181.7
15	**Nuclear Development Variance**	(55.6)	(110.8)	(55.1)	37.2
16	**Transmission Outages and Restrictions Variance**	0.7	0.1	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	(0.6)	0.6	0.8	1.4
18	**Capacity Refurbishment Variance - Nuclear**	(0.3)	(8.5)	0.2	13.3
19	**Nuclear Fuel Cost Variance**	(15.7)	6.4	9.4	0.0
20	**Bruce Lease Net Revenues Variance**	324.5	249.4	196.0	368.2
21	**Income and Other Taxes Variance - Nuclear**	(12.1)	(31.6)	(42.9)	(31.6)
22	**Tax Loss Variance - Nuclear**	247.2	413.7	356.8	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	123.0	327.3
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	56.7
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	6.6	3.7	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	10.7	20.8	1.5	5.1
27	**Total**	673.3	619.0	615.3	1,212.5
28	**Grand Total**	646.7	600.0	642.3	1,321.4

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 2
(Recast of 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	5.4	0.0	0.0	0.0	5.4
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)	15.1	27.3	0.0	0.0	27.0
	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	122.3	0.0	0.7	0.0	123.0
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	(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	202.4	(201.4)	7.4	0.0	615.3
28	**Grand Total**	591.5	217.4	(174.0)	7.4	0.0	642.3

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 3
(Recast of H1-1-1 Table 1c)
Deferral and Variance Accounts
Continuity of Account Balances - 2011 to 2012 ($M)

Line No.	Account	Year End Balance 2011	Projected 2012 Transactions	Projected 2012 Amortization[1]	Projected 2012 Interest	Projected 2012 Transfers	(a)+(b)+(c)+(d)+(e) Projected Year End Balance 2012
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(41.4)	13.7	38.3	(0.3)	0.0	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	10.6	16.6	5.1	0.3	0.0	32.6
3	**Hydroelectric Incentive Mechanism Variance**	(1.4)	0.0	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.5	4.4	0.0	0.0	0.0	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(6.8)	(0.1)	4.4	(0.1)	0.0	(2.6)
6	**Tax Loss Variance - Hydroelectric**	68.0	0.0	(20.6)	0.8	0.0	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	1.8	0.0	0.0	0.0	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	5.4	10.9	0.0	0.2	0.0	16.5
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	2.7	0.0	0.0	0.0	2.7
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)	(1.7)	4.3	(0.1)	0.0	(3.4)
12	**Total**	27.0	48.3	32.8	0.8	0.0	108.9
	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	180.0	(21.4)	1.3	0.0	181.7
15	**Nuclear Development Variance**	(55.1)	32.1	60.4	(0.2)	0.0	37.2
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	0.9	(0.3)	0.0	0.0	1.4
18	**Capacity Refurbishment Variance - Nuclear**	0.2	8.3	4.6	0.1	0.0	13.3
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	305.2	(136.0)	3.1	0.0	368.2
21	**Income and Other Taxes Variance - Nuclear**	(42.9)	(5.4)	17.2	(0.5)	0.0	(31.6)
22	**Tax Loss Variance - Nuclear**	356.8	0.0	(107.9)	4.4	0.0	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	123.0	201.1	0.0	3.1	0.0	327.3
24	**Impact for USGAAP Deferral - Nuclear**	0.0	55.9	0.0	0.8	0.0	56.7
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	8.9	(11.4)	0.0	6.1	5.1
27	**Total**	615.3	786.9	(201.8)	12.2	0.0	1,212.5
28	**Grand Total**	642.3	835.2	(169.0)	13.0	0.0	1,321.4

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 will be terminated on December 31, 2012, and the remaining balance of less than $0.1M will be 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 will be terminated on December 31, 2012, and the remaining balances of less than $0.1M, $6.0M and $0.1M respectively will be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

Numbers may not add due to rounding.

Table 4
(Recast of 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	Projected 2012 Hydroelectric	Projected 2012 Nuclear	Projected 2012 Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Pension Costs - EB-2010-0008**[2]	4.8	95.0	99.8	8.1	162.8	170.9
2	**Forecast OPEB Costs - EB-2010-0008**[2]	6.7	132.8	139.4	8.3	166.7	175.0
3	**Total Forecast Pension and OPEB Costs**	11.5	227.8	239.3	16.4	329.5	345.9
4	**Actual/Projected Pension Costs**[3,4]	7.8	162.2	170.0	14.8	287.0	301.8
5	**Actual/Projected OPEB Costs**[3,4]	7.7	160.3	168.1	11.0	215.7	226.7
6	**Total Actual/Projected Pension and OPEB Costs**	15.6	322.5	338.1	25.8	502.7	528.5
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)	3.0	67.2	70.2	6.7	124.2	130.9
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)	1.1	27.6	28.7	2.7	49.0	51.7
9	**Addition to Variance Account - Regulatory Tax Impact**[5]	1.3	27.6	28.9	1.5	27.9	29.5
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)	5.4	122.3	127.7	10.9	201.1	212.1

Notes:

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

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 1a / 12 months) x 10 months)	4.8	95.0	6.7	132.8
5a	2012 Amount ((line 2a / 12 months) x 12 months)	8.1	162.8	8.3	166.7

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 Projected amounts for 2012 represent the regulated portion of OPG's total pension and OPEB projected costs provided at pages 3 and 5 of Ex. H2-1-3, Attachment 4.

5 From Table 5, line 8.

Numbers may not add due to rounding.

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

Line No.	Particulars	Mar - Dec 2011 Hydroelectric	Mar - Dec 2011 Nuclear	Mar - Dec 2011 Total	Projected 2012 Hydroelectric	Projected 2012 Nuclear	Projected 2012 Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Regulatory Income Tax Impact**[1]	0.1	1.6	1.7	0.9	18.8	19.7
	Actual Additions to / Deductions from Regulatory Earnings Before Tax						
2	**Pension Costs** (Table 4, line 4)	7.8	162.2	170.0	14.8	287.0	301.8
3	**OPEB Costs** (Table 4, line 5)	7.7	160.3	168.1	11.0	215.7	226.7
4	**Less: Pension Plan Contributions**[2,3]	9.0	187.2	196.2	14.5	282.4	296.9
5	**Less: OPEB Payments**[2,3]	2.6	54.4	57.1	4.1	80.1	84.2
6	**Net Additions to Regulatory Earnings Before Tax**	3.9	80.9	84.8	7.2	140.2	147.4
7	**Actual Regulatory Income Tax Impact**[4] (line 6 x tax rate / (1 - tax rate))	1.4	29.2	30.6	2.4	46.7	49.1
8	**Addition to Variance Account - Regulatory Tax Impact** (line 7 - line 1)	1.3	27.6	28.9	1.5	27.9	29.5

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 No.		2011 Hydroelectric	2011 Nuclear	2011 Total	2012 Hydroelectric	2012 Nuclear	2012 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, col. a / 12 months) x 10 months)			0.1			
8a	Nuclear Mar-Dec 2011 Amount ((line 6a, col. b / 12 months) x 10 months)			1.6			
9a	Hydroelectric 2012 Amount ((line 6a, col. d / 12 months) x 12 months)						0.9
10a	Nuclear 2012 Amount ((line 6a, col. e / 12 months) x 12 months)						18.8

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 Projected amounts for 2012 represent the regulated portion of OPG's total pension and OPEB cash amounts provided at page 5 of Ex. H2-1-3, Attachment 4.

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

Table 6
(Recast 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**	10.3	10.3	24	5.2	5.2	10.3	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	32.6	32.6	24	16.3	16.3	32.6	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(1.4)	0.0	N/A	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.9	0.0	N/A	0.0	0.0	0.0	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(2.6)	(2.6)	24	(1.3)	(1.3)	(2.6)	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**	1.0	0.0	N/A	0.0	0.0	0.0	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	16.5	16.5	48	4.1	4.1	8.3	8.3
9	**Impact for USGAAP Deferral - Hydroelectric**	2.7	2.7	24	1.3	1.3	2.7	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.4)	(3.4)	24	(1.7)	(1.7)	(3.4)	0.0
11	**Total** (lines 1 though 10)	108.9	104.4		48.0	48.0	96.1	12.8
12	**Total Approved 2011-2012 Production[4] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.42	

Notes:
1 From 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.

Filed: 2012-12-07
EB-2012-0002
Exhibit L
Tab 2
Schedule 1 Staff-21
Attachment 1-Table 7

Table 7
(Recast of H1-2-1 Table 2)
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**	181.7	181.7	24	90.8	90.8	181.7	0.0
2	**Nuclear Development Variance**	37.2	37.2	24	18.6	18.6	37.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.4	1.4	24	0.7	0.7	1.4	0.0
4	**Capacity Refurbishment Variance - Nuclear[4]**	13.3	13.1	24	6.6	6.6	13.1	0.2
5	**Bruce Lease Net Revenues Variance**	368.2	368.2	48	92.1	92.1	184.1	184.1
6	**Income and Other Taxes Variance - Nuclear**	(31.6)	(31.6)	24	(15.8)	(15.8)	(31.6)	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**	327.3	327.3	48	81.8	81.8	163.6	163.6
9	**Impact for USGAAP Deferral - Nuclear**	56.7	56.7	24	28.3	28.3	56.7	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	5.1	5.1	24	2.6	2.6	5.1	0.0
11	**Total** (lines 1 through 10)	1,212.5	1,212.4		432.3	432.3	864.6	347.9
12	**Total Approved 2011-2012 Production[5] (TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						8.48	

Notes:
1 From 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 refurbishment 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.

Table 8
(Recast of 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 ($/MWh)**	1	34.13	38.20	12%
2	**Nuclear Rate Including Rider ($/MWh)**	2	55.85	60.00	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 ($/MWh)** (line 1 x line 3 / line 5)		9.57	10.71	
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		40.19	43.18	
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		49.77	53.89	
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 Table 6, 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 Table 7, line 13.

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

Board Staff Interrogatory #22

Ref: Exh H1-1-1 Tables 1 and 5

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

Interrogatory

The total balance as at December 31, 2012 in the Pension and OPEB Cost Variance Account shown in Table 1 is $349.8M (i.e., $16.7M + $333.1M shown in lines 8 and 23 of column (d) respectively) whereas the total balance in Table 5 is $346M (i.e. $95.9M + $250.3M totals shown in line 10 of columns (c) and (f) respectively), which represents a difference of $3.8M in the total balances in the two tables.

a) Please indicate what are the correct balances for this account as at December 31, 2011 and December 31, 2012.

b) Please make adjustments as appropriate and recast all applicable tables and related amounts in the application

Response

a) and b)

All balances are correct as filed. The apparent difference of $3.8M consists of $3.6M in interest charges on the account balance as shown at Ex. H1-1-1 Tables 1b and 1c, lines 8 and 23, col. (d). Exhibit H1-1-1 Table 5 shows the derivation of account additions, not balances, and excludes interest charges. The remaining difference of $0.2M is due to rounding, as amounts in the pre-filed evidence are displayed to one decimal place.

Board Staff Interrogatory #23

Ref: Exh. H2-1-3

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

Interrogatory

a) Please provide a breakdown showing the variances between the approved forecast and the actual (or projected) amounts in relation to the components of net periodic pension and benefit cost in the table below.

b) Please provide the reasons for the variances with respect to each component amount in the table below.

Components of Net Periodic Pension and Benefit Cost	Pension Variance Amount		OPEB Variance Amount	
	2011	2012	2011	2012
Employer current service cost				
Interest cost				
Expected return on plan assets				
Amortization of past service costs				
Amortization of net actuarial loss (gain)				
Total				

Response

a) The requested chart is provided below. As noted at Ex. H2-1-3, p.2, lines 14-19 and further discussed in response to interrogatory L-2-1 Staff-21, variances recorded in the Pension and OPEB Cost Variance Account for March to December 2011 and full year 2012 are calculated using a "standard approach" by comparing actual costs to reference amounts calculated as 10/24 and 12/24, respectively, of the two-year 2011/2012 forecast pension and OPEB costs approved in EB-2010-0008. Variances in the components of the costs presented below have been calculated using the same approach.

Components of Net Periodic Pension and Benefit Cost	Pension Variance Amount[1]		OPEB Variance Amount[1]	
	2011[2]	2012	2011[2]	2012
Employer current service cost	31.6	85.7	11.9	22.2
Interest cost	(6.4)	20.1	(3.0)	3.5
Expected return on plan assets	(3.0)	(46.4)	n/a	n/a
Amortization of past service costs	3.2	(3.8)	0.2	(0.1)
Amortization of net actuarial loss (gain)	23.5	100.8	16.4	29.9
Total	48.9	156.5	25.5	55.6

[1] Numbers may not add due to rounding
[2] March 1 to December 31, 2011 only

b) As discussed in Ex. H2-1-3, section 3.2, lower than forecast discount rates are the primary source of variance between the actual/projected 2011 and 2012 pension and OPEB costs and the corresponding reference amounts based on EB-2010-0008 approved forecasts, with differences in asset values and returns also contributing to the variance. The main causes of the significant variances in pension and OPEB cost components shown in the chart in part (a) are the same as the above sources of the total variances discussed in the pre-filed evidence. To the extent that the amount of variance in a component of the costs is significant, the material below indicates which of these sources have specifically contributed to the variance.

For both pension and OPEB, the variances in the 2011 and 2012 current service cost are primarily due to lower-than-forecast discount rates for these two years. This was also the main reason for the 2012 variance in the interest cost for pension.

The projected amount of expected return on pension plan assets for 2012 is higher than the corresponding component of the 2012 reference amount mainly as a result of 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, partially offset by a lower-than-forecast expected rate of return for 2012.

The higher actual/projected amortization of net actuarial loss/gain for OPEB for both years was largely caused by lower discount rates for 2011 and 2012. These lower discount rates were also the main reason for higher actual/projected amortization of net actuarial loss/gain for pension for both years, partially offset by higher-than-forecast pension fund asset values at the end of 2010 and 2011 noted above.

Board Staff Interrogatory #24

Ref: Exh H2-1-3 pages 6 to11

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

Interrogatory

The pre-filed evidence states that 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.

a) Please provide the assumptions and data including the source(s) of the data underlying the discount rates cited for 2013, and provide the expected long-term bond rates and related assumptions and data for 2013.

b) Please provide 2014 projected pension and OPEB costs in the format of Chart 2 (page 11) and the assumptions and data including the source(s) of the data underlying the discount rates cited for 2014.

c) What is the trend that OPG forecasts for discount rates over the next five years and the longer term?

d) For Chart 1 (Exh H2-1-3 page 6), please add "Inflation rate" and "Salary schedule escalation rate" under Assumption (i.e., please add new rows in the chart and provide the related information). In addition, please provide projections of the assumptions (as amended above) in Chart 1 continuing for the years 2013 to 2017 inclusive (i.e., please add new columns for these years in the chart and provide the related information).

Response

a) OPG's independent actuary, currently Aon Hewitt, provides the discount rates for the purposes of determining OPG's actual and forecast pension and OPEB costs. The pre-filed evidence at Ex. H2-1-3, section 4.2 cites the projected discount rates for 2013 provided by Aon Hewitt at the time of the preparation of OPG's pre-filed evidence for the purposes of projecting 2013 pension and OPEB costs presented in the same section.

   OPG notes that discount rates have declined further since the projection in the pre-filed evidence was prepared. The discount rates for 2013 pension and OPEB costs under USGAAP and CGAAP will be known as of the end of 2012 (with the exception of 2013 long-term disability benefit plan costs under USGAAP, which must be determined using discount rates as of 2013 year-end). Prior to the oral hearing, OPG plans to file an update to its evidence to reflect 2013 pension and OPEB costs based on the actual discount rates as of the end of 2012.

b) OPG declines to provide a projection of 2014 pension and OPEB costs as the information is not relevant to the clearance of 2012 audited balances. Additionally, as experience has shown, significant variances may occur between forecast and actual pension and OPEB costs. The main drivers of variance for pension and OPEB costs are discount rates and pension fund performance, both of which are difficult to forecast and beyond management control. Discount rates used to calculate 2014 pension and OPEB costs will be established at the end of 2013.

c) OPG does not forecast the pension and OPEB discount rates. OPG's projections of pension and OPEB costs are derived using the long-term discount rate determined in accordance with USGAAP and CGAAP (as described in part (a) above) based on actual bond yields in existence at the time the projection is prepared.

d) Amended Chart 1 is provided below. Information for years beyond 2013 is not provided for reasons outlined in part b) above.

Chart 1, As Amended

Assumption	2011 Actual	2012 Projection	2013 Projection	2011 OEB-Approved	2012 OEB-Approved
Discount rate for pension	**5.80% per annum**	**5.10% per annum**	**4.70% 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**	**4.80% per annum**	7.00% per annum	7.00% per annum
Discount rate for long- term disability	**4.70% per annum**	**4.00% per annum**	**3.70% 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**	**2.75% 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**	**6.5% in 2012**	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

AMPCO Interrogatory #03

Ref: Exhibit H1-1-1 Page 2 Line 28 to Page 3 Line 2

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

Interrogatory

Preamble: The evidence indicates that Tables 2 through 15 (Exhibit H1-1-1) provide supporting calculations showing the derivation of entries into each of the accounts during 2011 and 2012. Projections for 2012 are based on information as of June 30, 2012.

Please recast all applicable tables and related amounts for 2012 to reflect the latest information available.

Response

OPG plans to file an update to its evidence to reflect material changes in February 2013. A recast of all applicable tables to reflect actual 2012 information will be contained in that update.

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.

AMPCO Interrogatory #05

Ref: Exhibit H2-1-1 Page 3 Lines 12-17
Exhibit H2-1-1 Page 4 Lines 8-13

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

Interrogatory

Preamble: At the first reference, OPG provides the accounting consequences of the current approved ONFA Reference Plan which includes a 2011 year-end net increase to the carrying book value of the ARO and ARC of $943M at a discount rate of 3.43 per cent. At the second reference, OPG states the lower discount rate reflects the impact of current financial market conditions on long-term bond rates.

a) Please confirm the derivation of the discount rate of 3.43 per cent, including by providing supporting calculations and inputs.

Response

a) Please refer to the response to Interrogatory L-1-7 SEC-12.

AMPCO Interrogatory #06

Ref: Exhibit H2-1-2 Page 5 Lines 21-24

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

Interrogatory

Preamble: OPG states that the extended average service life of the Bruce units is projected to increase the fair value of the derivative liability as at December 31, 2012 arising from Supplemental Rent Revenues under the Bruce Net Lease.

a) Please produce supporting analysis of the forecasted average service life of the Bruce units.

Response

As noted in response to interrogatories L-1-1 Staff-08 and L-1-7 SEC-10, the partial rebate by OPG to Bruce Power of supplemental rent payments currently applies only to the Bruce B units. Therefore, the increase in the fair value of the derivative liability as at December 31, 2012 is related only to the extension of the average service life, for depreciation purposes, of the Bruce B station from December 31, 2014 to December 31, 2019.

The service life extension, for depreciation purposes, was based on OPG having high confidence that the condition of the pressure tubes for the Bruce B units should allow the units to operate longer, consistent with Bruce Power's indicated intent to do so. OPG obtained high confidence in this regard as of the end of 2012 given that the Fuel Channel Life Management ("FCLM") project's work program concluded that there is high confidence with respect to extended service lives of Pickering Units 5 - 8. The FCLM project's work program is an OPG-initiated industry effort including Bruce Power L.P. and is being coordinated through the CANDU Owners Group.

Attachment 1, the memorandum of the Depreciation Review Committee for Regulated Business (December 2012), provides (at page 4) the analysis supporting the average service life for the Bruce B units.

DEPRECIATION REVIEW COMMITTEE

For

Regulated Business

December 2012

ONTARIO POWER GENERATION

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM **December 2012**

2012 Depreciation Review – Regulated Business

This memo seeks approval for recommendations resulting from the 2012 review of regulated business service lives for prescribed nuclear facilities and the Bruce nuclear generating stations and the Niagara Tunnel.

Background

The Depreciation Review Committee ("DRC") is convened annually to review the service lives for depreciation purposes of OPG's major facilities and a selection of asset classes in those facilities with the objective of reviewing all significant asset classes over a five year period. In 2011, Gannett Fleming Inc. ("GF"), an external consultant, was engaged to review the estimated average services lives of all asset classes and the average station end-of-life dates of OPG's prescribed facilities. The DRC's 2011 recommendations to adopt the findings of the GF review were approved.

A. Scope for 2012 Review

Since all asset classes of the prescribed facilities were covered in last year's review by GF, the approach in 2012 was to focus primarily on the review of service lives of the regulated stations.

Nuclear

Previous years' approved DRC recommendations noted that the work program necessary to determine the feasibility of achieving extended service lives of pressure tubes at Pickering was on-going and that the Fuel Channel Life Cycle Management project ("FCLM") was a key part of that work program. The work program has been substantially completed in 2012. Therefore, in this year's review, the DRC considered the impact of the results of this work program on the service lives at the Pickering B station and recommends an extension of those service lives. The DRC also addressed the implications on the service lives of the Pickering A and Bruce A and B nuclear generating stations.

With the assessment of the above noted station life impacts completed, the DRC will begin a new five year review cycle for nuclear asset classes in 2013 as recommended by the GF review.

Regulated Hydroelectric

Since all asset classes of the prescribed facilities were covered in last year's review by GF, the approach in 2012 was to focus on the review of service life for depreciation purposes on a major asset class related to the Niagara Tunnel (tunnel lining) which is expected to be placed in service in 2013. The DRC will continue the five year review cycle for regulated hydroelectric asset classes in 2013.

ONTARIO POWER GENERATION

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM **December 2012**

2012 Depreciation Review – Regulated Business

B. Prescribed Nuclear Facilities

Pickering

As noted in the previous year's DRC recommendations, OPG's expectation was that high confidence would be obtained in continued operation for Pickering B Units 5 – 8 by December 2012, based primarily on the results of the FCLM project. The DRC received technical and planning confirmation in the fourth quarter of 2012 that the FCLM project indicated high confidence that Pickering B Units 5 - 8 could be operated until at least 247,000 effective full power hours (EFPH). The DRC has concluded that OPG can now demonstrate high confidence in Pickering B Units 5 – 8 achieving at least 247,000EFPH, which results in the following the end-of-life dates for depreciation purposes:

Unit 5 Q1 2020
Unit 6 Q2 2019
Unit 7 Q4 2020
Unit 8 Q4 2020

This results in a revised average station end-of-life date for depreciation purposes for Pickering Units 5 - 8 of April 30, 2020.

The average station end-of-life date for Pickering A Units 1 and 4 remained at December 31, 2021 in the 2011 DRC recommendations. As indicated in previous years' approved DRC recommendations, there were technical and economic considerations which would have prevailed against the operation of Pickering A Units 1 and 4 in the absence of the continued operation of at least two units of Pickering B Units 5 - 8. However at that time, OPG could not claim high confidence to support a change in the end-of-life dates for Pickering A Units 1 and 4 from the then current date due to the ongoing execution of the FCLM project for achievement of high confidence in the extended service lives of Pickering B Units 5 – 8. Also, it was noted that this would avoid potentially frequent changes to the average end-of-life dates for depreciation purposes over a short period of time.

Now that high confidence has been obtained with respect to the extended service lives of Pickering B Units 5 - 8, the DRC is recommending that the end-of-life dates for Pickering A Units 1 and 4 should be aligned with those of the last two units at Pickering B Units 5 – 8. Thus, the revised average station end-of-life date for depreciation purposes should be adjusted to December 31, 2020.

ONTARIO POWER GENERATION

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM **December 2012**

2012 Depreciation Review – Regulated Business

Recommendations for Prescribed Nuclear Facilities

1. The average end-of-life date for depreciation purposes for Pickering B Units 5 – 8 should be revised from September 30, 2014 to April 30, 2020. The estimated impact on annual depreciation expense beginning in 2013 will be a decrease of approximately $85 million.

2. The average end-of-life date for depreciation purposes for Pickering A Units 1 and 4 should be revised from December 31, 2021 to December 31, 2020. The estimated impact on annual depreciation expense beginning in 2013 will be an increase of approximately $13 million.

3. The average end-of-life date for depreciation purposes for Darlington should remain at December 31, 2051.

(The estimated impact on depreciation expense does not include the depreciation impact from the resulting adjustments to the ARO estimate that are expected to occur at year-end 2012).

The recommended effective date for the end-of-life changes is the current fiscal period ending December 31, 2012.

C. Bruce Nuclear Generating Stations

Bruce A

Refurbishment work on Bruce A Units 1 and 2 has been completed and both units have returned to service in 2012. As indicated in the 2011 DRC recommendations, based on the currently assumed nominal operating life of 30 calendar years for the replaced pressure tubes, these units would be expected to reach their end of life in approximately 2042.

Bruce A Units 3 and 4 are currently operating with their original pressure tubes. As indicated in previous years and based on publicly available information, Bruce Power's intent is to operate these units into the early 2020s at which time the pressure tubes would be replaced and the units refurbished. This is supported by the results of the FCLM project in which Bruce Power has been a participant along with OPG providing high confidence that the pressure tubes can reach beyond nominal life. Based on this high confidence and Bruce Power's intent of replacing the pressure tubes and refurbishing the units at that time, a revised end-of-life date of December 31, 2054 for these units is recommended assuming an extended 30-year nominal operating life of the replaced pressure tubes.

Based on the average end of life dates for Bruce A Units 1 and 2 of December 31, 2042 and for Bruce A Units 3 and 4 of December 31, 2054, the revised average station end-of-life date for depreciation purposes for Bruce A Units 1 – 4 is December 31, 2048.

ONTARIO POWER GENERATION

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM **December 2012**

2012 Depreciation Review – Regulated Business

Bruce B

As noted by the DRC in previous years, the then expectation around the service lives of the Bruce B Units 5 – 8 pressure tubes had resulted in December 31, 2014 as the average end-of-life dates for depreciation purposes. Even though Bruce Power's indicated intent has been to operate the Bruce B units longer, there was insufficient evidence at the time to support a date for depreciation purposes beyond December 31, 2014.

Given the FCLM project's work program aimed at reviewing pressure tube lives has been substantially completed in 2012, the DRC has concluded that there is now high confidence that the condition of the pressure tubes for each of the four units at Bruce B should allow these units to operate until approximately 2020.

Therefore, the DRC recommends the adoption of December 31, 2019 as the average station end-of-life date for depreciation purposes for Bruce B.

Recommendations for Bruce Nuclear Generating Stations

1. The average end-of-life date for depreciation purposes for Bruce A Units 1 – 4 should be revised from December 31, 2042 to December 31, 2048. The estimated impact on annual depreciation expense beginning in 2013 will be a decrease of approximately $10 million.

2. The average end-of- life date for depreciation purposes for Bruce B Units 5 – 8 should be revised from December 31, 2014 to December 31, 2019. The estimated impact on annual depreciation expense beginning in 2013 will be a decrease of approximately $25 million.

As noted previously, the recommended effective date of the above end-of-life changes is the current fiscal period ending December 31, 2012. The estimated impact on depreciation expense does not include the depreciation impact from the resulting adjustment to the ARO estimate that is expected to occur at year-end 2012.

D. Niagara Tunnel

The Niagara Tunnel is expected to be placed in service during 2013. The estimated service life for existing OPG tunnel linings is 75 years, which is consistent with industry practice and has been verified in last year's GF review. The technical specifications as provided under owner's mandatory requirement have a requirement for a service life of 90 years for the lining system and structures of the Niagara Tunnel Facility. An internal review of the technical specifications and construction by Hydro-Thermal Operations staff also confirmed that the service life of the tunnel lining is 90 years. The DRC has accepted this as sufficient evidence.

Recommendations for Niagara Tunnel

For the Niagara Tunnel, the service life for depreciation purposes for the tunnel lining system and structures should be 90 years. This lining should be recorded in a separate asset class. The impact on annual depreciation of using the 90-year life for the Niagara Tunnel lining instead of the 75-year life is estimated to be an annual reduction in depreciation expense of approximately $1 million.

700 University Avenue, Toronto, ON, M5G 1X6

MEMORANDUM **December 2012**

2012 Depreciation Review – Regulated Business

The DRC includes representatives for each operating business unit as well as representatives having experience in finance and accounting, investment planning and rate regulation.

Representatives on the DRC are listed below:

Dennis Dodo, Chair, VP, Shared Financial Services

David Bell, Senior Manager, Shared Financial Services
Carla Carmichael, VP, Nuclear Finance
Alec Cheng, Director External Reporting & Accounting Policy
Alex Kogan, Manager Regulatory Finance
Bill Lanting, Finance Controller, Hydro/Thermal Finance
John Mauti, VP, Business Planning & Reporting
Randy Pugh, Director, Regulatory Research & Analysis
Stephen Rogers, Director Asset Planning & Integration, Investment Planning
Jay Scrinko, Director Controllership, Hydro/Thermal Finance
Charanjit Singh, Director Accounting, Shared Financial Services
John Tipold, Financial Accounting Analyst, Shared Financial Services

AMPCO Interrogatory #07
(NON-CONFIDENTIAL VERSION)

Ref: Exhibit H2-1-2 Page 7 Lines 2-4

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

Interrogatory

Preamble: OPG projects revenues based on waste volume information received from Bruce Power and is projecting those volumes to be higher in 2012 than originally anticipated.

a) Please provide updated data for actual volumes in 2012.

b) Please quantify and comment on any variance from the projections for 2012.

Response

a) & b) As noted in Ex. H2-1-2, section 4.3 and the preamble to this question, OPG's revenue projections for the provision of low and intermediate level waste management services to Bruce Power L.P. ("Bruce Power") are based on forecasted waste volume information from normal operations of the Bruce facilities as received from Bruce Power. OPG is required to maintain the capacity to accept all of the waste generated by Bruce Power. However, as a result of volume reduction initiatives by Bruce Power, the actual volumes received by OPG during 2012 were approximately 60 per cent and 70 per cent below the projected volumes reflected in the pre-filed evidence for low level and intermediate level waste, respectively. The following chart provides confidential information for the 2012 projected and actual volumes of low and intermediate level waste and resulting variances.

	Low Level Waste			Intermediate Level Waste		
	Projection	Actual	Variance (actual < projection)	Projection	Actual	Variance (actual < projection)
Volume (m^3)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AMPCO Interrogatory #08

Ref: Exhibit H2-1-2 Page 10 Lines 10-16

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

Interrogatory

Preamble: OPG indicates that 2012 earnings for the Bruce portion of the nuclear segregated funds are projected to be $17.7 million above the EB-2010-0008 approved forecasts but that this amount may change before the end of the year.

a) Please update the amount of the $17.7 million variance using actual earnings numbers and updated projections to year end for 2012.

Response

a) OPG plans to file an update to its evidence to reflect material changes in February 2013. Actual 2012 information will be contained in that update.

AMPCO Interrogatory #09

Ref: Exhibit H2-2-1 Page 2 Lines 10-21 and Page 3 Lines 1-20

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

Interrogatory

a) Please provide a breakdown showing the contribution of each of the key elements of actual 2011 and projected 2012 planning and preparation work for NND (as described in the referenced section) to the balance of the Nuclear Development Variance Account.

Response

Please see response to L-1-7 SEC-17.

AMPCO Interrogatory #10

Ref: Exhibit H2-2-1 Page 8 Lines 3-7

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

Interrogatory

Preamble: OPG references a high confidence statement regarding the service lives of pressure tubes based on available research and development results Pickering and Darlington, which was to be presented to the OPG Board of Directors in order to make business decisions on the continued operations of Pickering and the refurbishment of Darlington.

a) Has this statement been delivered to and considered by the OPG Board of Directors?

b) If so, what decisions has the OPG Board of Directors made or confirmed as a result regarding the continued operations of Pickering and the refurbishment of Darlington.

c) Please produce a copy of the statement.

Response

a) The Chief Nuclear Officer orally updated the OPG Board of Directors in November 2012 on the status of the Fuel Channel Life Management Project ("FCLMP") including confirming high confidence the fuel channels for Pickering Units 5-8 can reach an operational life of 247,000 Effective Full Power Hours ("EFPH") and medium confidence that Darlington fuel channels can reach an operational life of 210,000 EFPH for Units 1-4.

b) The 2012 results of the FCLMP support previous assumptions around end-of-life for both stations. As a result, the OPG Board of Directors, as part of ongoing business planning, has approved continued expenditures on Pickering Continued Operations post 2012 given OPG's high confidence assessment that Pickering end-of-life can be extended to 2020. Darlington's continuing medium confidence assessment did not change planning assumptions and the OPG Board of Directors has also approved the continuation of Darlington Refurbishment expenditures to ensure readiness for a 2016 project start date.

c) As noted in a), above, the statement was made orally.

AMPCO Interrogatory #11

Ref: Exhibit L-3-1 Page 1 Lines 37-41

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

Interrogatory

Preamble: OPG indicated that it will deliver audited 2012 account balances "prior to the commencement of the oral hearing".

a) Please confirm when audited balances will be provided, and specifically confirm whether they will be provided reasonably in advance of the settlement conference for this hearing.

Response

OPG plans to file audited 2012 account balances as early as possible in February 2013. Since the Settlement Conference is currently scheduled for February 11, 2013 (as per the OEB's Procedural Order #2), OPG will use best efforts to try to ensure that such information is filed prior to the initiation of the Settlement Conference.

CCC Interrogatory #05

Ref: Ex. A2/T1/S1/p. 1 and H1/T1/S1/p. 11

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

Interrogatory

OPG is planning to defer clearance of the Hydro Electric Incentive Mechanism Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account because the studies that the studies that the OEB ordered remain underway. When will the studies be completed? Please explain how these studies can potentially impact the balances in these accounts?

Response

In its Decision with Reasons for EB-2010-0008, the Board directed OPG to provide a more comprehensive analysis of the benefits, among other things, of the Hydro Incentive Mechanism ("HIM") for ratepayers and the interaction between this mechanism and surplus base load generation ("SBG"). This analysis is ongoing and will be complete by the time OPG files its next payment amounts application for its prescribed hydroelectric facilities. OPG currently plans to make such an application in 2013.

In 2011 and 2012, OPG recorded amounts in the HIM and SBG Variance accounts as prescribed by the Board. While OPG does not anticipate that the referenced analysis will have any impact on the recorded balances in these accounts, OPG does expect that the results of the analysis as well as a discussion of the operation of the Sir Adam Beck facility will be required during the review of these balances (See Ex. H-1-1-1, p.11, lines 9-15).

CCC Interrogatory #06

Ref: Ex. H1/T1/S1/p. 8

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

Interrogatory

The evidence states that the December 31, 2012 balance in the Impact for USGAAP Deferral Account is projected to be $59.3 million with $2.7 million attributed to regulated hydroelectric and $56.7 million attributed to nuclear "based on the attribution of the underlying financial impacts." Please explain, specifically, how the attribution was determined?

Response

The OPG-wide LTD benefit plan amounts were attributed to each of regulated hydroelectric and nuclear using labour-related allocation approaches, as discussed more fully in response to interrogatory L-1-1 Staff-34(c).

PWU Interrogatory #02

Ref:

Ref (1): EB-2010-0008, Draft Payment Amounts Order/ Appendix B/Table 1 (Regulated Hydroelectric Payment Amount)

Ref (2): EB-2010-0008, Draft Payment Amounts Order/ Appendix C/Table 1 (Nuclear Payment Amount)

Ref (3): Exhibit L/Tab 2/Schedule 1 Staff-21, a) and b)/Pages 1-2 of 2

Ref (4): Exhibit H1/Tab 1/Schedule 1/Table 5 (Pension and OPEB Cost Variance Account)

Ref (5): Exhibit L/Tab 2/ Schedule 1 Staff-21/Attachment 1-Table 4 (Recast of H1-1-1 Table 5)

Ref (1) provides the methodology for calculating the regulated hydroelectric payment amount for the test period January 1, 2011 to December 31, 2012 and Ref (2) provides the methodology for calculating the nuclear payment amount for the period January 1, 2011 to December 31, 2012.

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

Interrogatory

a. Please confirm that the methodology used in EB-2010-0008 for determining the payment amounts for the test period January 1, 2011 to December 31, 2012 was set in a manner such that OPG is able to recover, over the period March 1, 2011 to December 31, 2012, 22/24 of the combined approved revenue requirements for regulated hydroelectric and nuclear for the test period January 1, 2011 to December 31, 2012.

b. Please confirm that the methodology used in EB-2010-0008 for determining the payment amounts for the test period January 1, 2011 to December 31, 2012 was set in a manner such that OPG is able to recover, over the period March 1, 2011, to December 31, 2012, 22/24 of the combined 2011 full year forecast pension and OPEB costs and the 2012 full year forecast pension and OPEB costs that underpinned approved revenue requirements for regulated hydroelectric and nuclear for the test period January 1, 2011 to December 31, 2012.

c. Please confirm that forecast pension and OPEB costs for the period March 1, 2011 to December 31, 2012, as provided in Ref (4) were consistent with the methodology used for determining the payment amounts in EB-2010-0008.

d. Was the methodology used to calculate Forecast Pension and OPEB costs for the period March 1, 2011 to December 31, 2012, as provided in Ref (5), consistent with the methodology employed in EB-2010-0008 to determine the payment amounts?

Response

a) b) OPG confirms that the methodology used in determining the EB-2010-0008 payment amounts effective March 1, 2011 is such that in effect OPG is able to recover 22/24 of the revenue requirement for the test period from January 1, 2011 to December 31, 2012 over the period from March 1, 2011 to December 31, 2012. This applies equally to regulated hydroelectric and nuclear, and to all components of the revenue requirement.

c) Confirmed.

d) No, as discussed in L-2-1 Staff-21.

Board Staff Interrogatory #25

Ref: Exh H1-2-1 page 1

Issue Number: 3

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

Interrogatory

At line 18 of the pre-filed evidence it states that, "OPG proposes to recover resulting variances in recovery amounts during the period January 1, 2013 to the effective date of the new riders through additional Interim Period Shortfall Riders ("IPSR") ..."

Please confirm that the reference should be to the implementation date of the new riders.

Response

Confirmed. A corrected Ex H1-2-1 page 1 will be issued as part of the updated evidence.

Board Staff Interrogatory #26

Ref: Exh I1-1-1
Exh I1-1-2

Issue Number: 3

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

Interrogatory

OPG is proposing to clear deferral and variance account balances on the basis of audited balances for 2011 and forecast balances for 2012, with audited balances to follow in February 2013.

a) With the exception of EB-2010-0008, please provide examples of any other cases where the Board approved forecast balances for disposition, and audited balances were filed following the technical conference or following the close of the record.

b) How does OPG propose the Board should procedurally address any follow-up inquiry from Board staff and intervenors regarding the audited figures provided in the 2012 audited financial statements at that stage of the proceeding?

c) Please determine rate riders and bill impact if only the 2011 audited balances are recovered.

Response

Parts a though c: The questions are based on an incorrect premise in respect of OPG's proposed approach.

OPG does not propose to "clear deferral and variance account balances on the basis of audited balances for 2011 and forecast balances for 2012, with audited balances to follow in February 2013."

OPG's proposal, as stated at Ex I1-1-1, page 1, lines 9-11 and again at lines 16-17, is that, "The final rider will be set during the Payment Amount Order process using audited 2012 account balances." Given the schedule set out in Procedural Order 2, it appears that the audited 2012 account balances will likely be available prior to the commencement of the oral hearing.

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	Test Period Nuclear	Test Period 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

Board Staff Interrogatory #28

Ref: Filing Guidelines for Ontario Power Generation Inc. (EB-2011-0286)
Exh H1-2-1 page 5

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

Interrogatory

Page 21 of the filing guidelines summarizes the filing of payment amount implementation information. Please provide a description of the settlement process with the IESO, including a description of the timelines associated with a rate rider implementation date of March 1, 2013, as an example

Response

The IESO settlement process is described in Chapter Nine of the Market Rules. OPG has discussed this matter with the IESO and, assuming an implementation date of March 1, 2013, and that no change to the payment structure is proposed, a final rate order establishing the new payment amount riders would have to be issued by March 20, 2013 in order for the IESO to update their systems and perform the settlement for March 2013 using the new values.

AMPCO Interrogatory #12

Ref: Exhibit H1-2-1 Page 2 Lines 8-11

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

Interrogatory

Preamble: OPG intends to calculate rate riders on the basis of the EB-2010-0008 OEB-approved 2011/2012 test period forecast production, rather than on the basis of a future production forecast, on the grounds that this is not a complete cost of service application with a future test period.

a) Why is OPG not using 2011/2012 actual production values to calculate rate riders?

b) Please provide actual production data for 2011 and 2012 and confirm whether such data has been audited.

c) Please quantify, summarize and comment on any variance between the 2011/12 actual production values and the EB-2010-0008 OEB-approved 2011/2012 test period forecast production.

d) Where actual production values are not available, please produce any updated production forecasts that are more recent than the EB-2010-0008 OEB-approved 2011/2012 test period forecast production.

e) Please quantify, summarize and comment on any variance between such updated forecast and the EB-2010-0008 OEB-approved 2011/2012 test period forecast production.

Response

a) OPG proposes that OEB-approved 2011 - 2012 test period forecast production be used in the calculation of the riders because it is the most recent OEB-approved production total.

b) As production values are not financial values, they are not, in and of themselves, audited as part of the audit of OPG's financial statements. Rather, the audited financial statements reflect the financial consequences of production having occurred. Production values are reported in conjunction with OPG's financial results in OPG's Management's Discussion & Analysis ("MD&A"). The actual production values from OPG's prescribed assets for 2011 reported in OPG's 2011 MD&A at page 12 of Ex. A3-1-1, Attachment 1, the financial consequences of which are reflected in OPG's 2011 audited consolidated financial statements provided in the same Attachment, are provided in Chart 1 below.

OPG has not reported or finalized its 2012 financial results at the time of responding to this interrogatory. As such, actual production from the prescribed assets for 2012 in Chart 1 below is provided as estimated on a preliminary basis.

Chart 1
Comparison of 2011 and 2012 Production

TWh	2011 Actual	2011 Board-Approved	Difference	2012 Estimated Actual	2012 Board-Approved	Difference
Regulated Hydroelectric	19.5	19.8	(0.3)	18.5	19.8	(1.3)
Nuclear	48.6	50.4	(1.8)	49.1	51.5	(2.4)

c) **Regulated Hydroelectric**

2011 Actual versus 2011 Board Approved

Actual Regulated Hydroelectric production during 2011 (19.5 TWh) was 0.3 TWh (less than 2 per cent) below Plan production (19.8 TWh). Annual mean flows for the Niagara and St. Lawrence Rivers were similar to the forecast plan flows for 2011. Production was less than plan during the first part of the year when flows were lower than the forecast plan flows.

2012 Estimated Actual versus 2012 Board Approved

Estimated actual Regulated Hydroelectric production for 2012 (18.5 TWh) is 1.3 TWh (6.6 per cent) below Plan production (19.8 TWh). Actual flows for the Niagara and St. Lawrence Rivers were lower than the forecast plan flows from May through December 2012, resulting in decreased production. Management of Surplus Baseload Generation ("SBG") also reduced production at the Niagara plants during 2012. Production was curtailed at Decew Falls during the fall of 2012 to support SBG management.

Nuclear

2011 Actual versus 2011 Board Approved

The actual nuclear production for 2011 of 48.6 TWh is 1.8 TWh lower than the 2011 OEB-approved forecast of 50.4 TWh.

The lower actual production for 2011 relative to the OEB-approved 2011 forecast is due to:

- A 2.1 per cent increase (96.6 days) in the combined nuclear forced loss rate ("FLR"). There was a 6.2 per cent increase in the Pickering FLR largely driven by equipment vulnerabilities. The largest contributors to unplanned losses were at Pickering Units 1 and 4 which included a steam leak on the turbine system, high condenser vacuum pressure on the heat transport system resulting in a reactor trip, moderator level control valve and system pump seal failures. This was offset by a slight decrease of 0.9 per cent in Darlington's FLR.

- There were 70.7 Forced Extension of Planned Outage (“FEPO”) days for Pickering in 2011 (63.9 days due to the Pickering Unit 5 planned outage being extended to address deposits in the calandria, and 6.8 days due to fuelling machine maintenance on Pickering Unit 4).

Offsetting the above, there were 17.0 fewer planned outage (“PO”) days for the combined nuclear fleet (8.0 fewer actual PO days for Darlington and 9.0 fewer actual PO days for Pickering). The 2011 OEB-approved forecast included an allowance for major unforeseen events. OPG no longer tracks major unforeseen events separately, but instead the impacts of any major unforeseen events have been included in the actual FLR and FEPO figures referenced above.

<u>2012 Estimated Actual versus 2012 Board Approved</u>
The nuclear production estimate of 49.1 TWh for 2012 is 2.4 TWh lower than the 2012 OEB-approved forecast of 51.5 TWh.

The lower production estimate for 2012 relative to the OEB-approved 2012 forecast is primarily due to:

- A 25.7 per cent increase (80.3 days) in PO days for the combined nuclear fleet. This includes the introduction of a 20-day Pickering Unit 1 mid-cycle outage aimed at improving plant reliability through preventative maintenance to reduce the risk of future forced outages and three unbudgeted planned outages that were not included in the approved nuclear outage and generation plan, partly offset by the early completion of the Darlington Unit 3 planned outage 14.7 days ahead of the business plan target.

- A 1.7 per cent increase (60.7 days) in the combined nuclear FLR (3.0 per cent increase at Pickering, 0.8 per cent increase at Darlington).

- 16.4 FEPO days for Pickering mostly due to maintenance required on the Unit 8 west fueling machine and on Unit 4 to ensure the pressurizing pump maintenance was successful.

The 2012 OEB-approved forecast included an allowance for major unforeseen events. OPG no longer tracks major unforeseen events separately, but instead the impacts of any major unforeseen events have been included in the estimated FLR and FEPO figures referenced above.

d) See response to part b).

e) See response to part c).

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.

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.

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 #15

Ref: Exhibit H1-2-1 Page 4 Line 28 to Page 5 Line 3

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

Interrogatory

Preamble: OPG provides a formula to calculate its proposed Interim Period Shortfall Riders and discusses the interim period production forecast if for example the implementation date of the new approved rider is March 1, 2013.

a) Please provide an Interim Period Shortfall Riders calculation based on a March 1, 2013 implementation date and provide references for all inputs.

Response

a) As set out in Ex. H1-2-1, pp. 4-5, if one were to assume a March 1, 2013 implementation date and the Regulated Hydroelectric and Nuclear Payment Riders derived from the projected December 31, 2012 balances contained in OPG's Application (Ex. H1-2-1, Tables 1 and 2), the calculation of the Interim Period Shortfall Riders ("IPSR") would be as follows.

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

IPSR = [(Approved Rider – Interim Rider) x Interim Period Production Forecast]
(Production Forecast used to set Approved Rider – Interim Period Production Forecast)

For Regulated Hydroelectric, the variables would have the following values:
Note: 2011 and 2012 Hydroelectric Production values are provided at L–2–1 Staff-16, Attachment 1, Table 2.

Approved Rider = $2.42/MWh (Ex. A1-1-2, p. 2, line 21)

Interim Rider = $0 (as per Procedural Order #1)

Interim Period Production Forecast
= (2011/2012 Average January + 2011/2012 Average February)
= (1.7+1.6)/2 + (1.5+1.6)/2 = 1.65 + 1.55 = 3.2 TWh

Production Forecast used to set Approved Rider
= 39.7 TWh (Ex H1-2-1, Table 1, line 12)

Interim Period Production Forecast
= 3.2 TWh

Therefore, the Hydroelectric IPSR would be calculated as follows:

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

$$= \frac{[(\$2.42 / MWh - \$0 / MWh) \times 3.2TWh]}{(39.7\ TWh - 3.2\ TWh)}$$

$= \$7.744 \times 10^6 / 36.5\ MWh \times 10^6$
$= \$0.21 / MWh$

For Nuclear, the variables would have the following values:
Note: 2011 and 2012 Nuclear Production values are provided at L–2–1 Staff-16, Attachment 1, Table 3.

Approved Rider = $8.51/MWh (Ex A1-1-2, p. 2, line 21)

Interim Rider = $4.33 (as per Procedural Order #1)

Interim Period Production Forecast
= (2011/2012 Average January + 2011/2012 Average February)
= (4.8+4.8)/2 + (4.1+4.2)/2 = 4.8 + 4.15 = 8.95 TWh

Production Forecast used to set Approved Rider
= 101.9 TWh (Ex H1-2-1, Table 2, line 12)

Interim Period Production Forecast
= 8.95 TWh

Therefore, the Nuclear IPSR would be calculated as follows:

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

$$= \frac{[(\$8.51 / MWh - \$4.33 / MWh) \times 8.95\ TWh]}{(101.9\ TWh - 8.95\ TWh)}$$

$= \$37.411 \times 10^6 / 92.95\ MWh \times 10^6$
$= \$0.40 / MWh$

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:

$$\$113.8\text{ M} / (39.7\text{ TWh} / 24\text{ months}) = \$68.81 / \text{MWh}$$

(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:

$$\$1{,}160.5\text{ M} / (101.9\text{ TWh} / 24\text{ months}) = \$273.34 / \text{MWh}$$

(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).

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CCC Interrogatory #07

Ref: Ex. H1/T2/S1/p. 2

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

Interrogatory

The evidence states that, "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." Has OPG prepared a nuclear and hydroelectric production forecast for 2013, 2014 and 2015? If so, please provide.

Response

As OPG proposes to calculate the riders based on the OEB-approved 2011-2012 production forecast and has included a mechanism to true-up the actual amounts collected to the balances approved for collection, OPG sees forecasts of 2013-2014 production to be of limited relevance in this proceeding. Nevertheless, OPG's current approved production forecast for 2013 is 18.0 TWh for regulated hydroelectric and 48.0 TWh for nuclear. While OPG does not have a current approved production forecast for 2014, the 2014 production figures underlying the 2013-2014 estimate contained in L-3-5 EP-02 are 21.3 TWh for regulated hydroelectric and 49.8 TWh for nuclear. 2015 production forecast information is not provided because it is not relevant to this proceeding.

CCC Interrogatory #08

Ref: Ex. A2/T1/S1/p. 2

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

Interrogatory

OPG plans to recover all balances over a two year period with the exception of the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Account. The latter two accounts are to be recovered over four years. Please set out all of the recovery options OPG considered and explain why those options were rejected.

Response

OPG initially considered a two year recovery period for all accounts. However, in order to mitigate the impact of the resulting payment riders on ratepayers, given the size of the balances anticipated in the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, OPG chose to request clearance of those two accounts over four years (January 1, 2013 through December 31, 2016). OPG felt that this change sufficiently mitigated the effect of the rider increases. No further options were considered.

Energy Probe Interrogatory #01

Ref: Exhibit H1, Tab 2, Schedule 1, Tables 1 & 2

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

Interrogatory

Column (f) in each Table apparently contains the sum of column's (d) and (e).
a) Is this correct?
b) What is meant by the column heading "…Amortization/Rider"?

Response

a) Column (f) at lines 1-11 in Ex. H1-2-1, Tables 1 and 2 contains the sum of columns (d) and (e). Column (f) at line 12 in both tables contains an input for the production value, as referenced in the corresponding footnotes. The value in column (f), line 13 in both tables is calculated by dividing the dollar value in column (f), line 11 by the production value in column (f), line 12.

b) "Amortization" refers to amounts presented in each table in column (f) at lines 1 through 11, which represent the combined amortization over the 24-month period of January 1, 2013 to December 31, 2014 (i.e., sum of columns (d) and (e)) for the respective individual accounts and in aggregate. "Rider" refers to the payment rider calculated at line 13, column (f) in both tables.

Energy Probe Interrogatory #02

Ref: Exhibit L, Tab 3, Schedule 1, Staff-27

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

Interrogatory

Line 3 in Table 1 of OPG's response to Board Staff Interrogatory #27 indicates that the "OPG Portion" is 13.6% of regulated hydroelectric and 35% of nuclear. Note 3 thereto is unclear in some respects.

a) Please provide a better and fuller explanation the "OPG Portion" than is given in Note 3.

The various forecasts of OPG production and demand referenced in the footnotes to Table 1 were prepared prior to this Application.

b) Is OPG confident that the consumer bill impact will not affect the residential consumer usage? Please provide a brief explanation of OPG's reasons.

Response

a) In order to obtain the "OPG Portion" percentages quoted, OPG's 2013 and 2014 production forecast available during the preparation of the pre-filed evidence (138.8 TWh) was divided by the forecast total provincial energy demand for 2013 and 2014 as follows:

   OPG Portion = 138.8 TWh / 285.6 TWh = 48.6%

   As noted in the referenced footnote, the source of the forecast provincial electricity demand is the forecast or 142.8 TWh for 2013 contained in the IESO 18-Month Outlook of June 22, 2012. In preparing the impact estimates, OPG assumed the 2014 forecast provincial demand to be the same as the 2013 provincial demand.

   The regulated hydroelectric and nuclear portions were derived by applying 48.6% of OPG portion to the relative shares of regulated hydroelectric and nuclear production used to calculate the riders, shown at line 8 of the referenced table, as follows:

   Regulated Hydroelectric Portion = 39.7 TWh / 141.6 TWh x 48.6% = 13.6%

   Nuclear Portion = 101.9 TWh / 141.6 TWh x 48.6% = 35.0%

b) OPG has not conducted any analysis on whether the estimated consumer bill impact would affect residential consumer usage.

SEC Interrogatory #25

Ref: H1/2/1, p. 3

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

Interrogatory

Please explain why the Applicant is proposing to recover the balances in the Pension and OPEB Variance Account over four years, and the Impact of USGAAP Deferral Account over two years, rather than in each case recovering those balances over the remaining average service lives of the employees. Please calculate the impacts on the hydroelectric and nuclear rate riders proposed (i.e. $2.42 and $8.51) of using remaining average service lives. Please provide a table showing the annual amounts recoverable from ratepayers, excluding interest, a) as proposed by the Applicant, and b) based on remaining average service lives. In the table, please include c) a column showing the annual cash costs (contributions or other actual payments) expected in each of those years related to pensions, OPEBs, and LTD, and d) a column showing the annual accounting costs, on an accrual basis, expected in each of those years for those categories of costs, assuming no change in input assumptions.

Response

OPG is proposing a four-year recovery period for the Pension and OPEB Cost Variance Account, rather than the standard two-year recovery period, to mitigate the impact on customer bills. Given the size of the projected balances in this account, OGP is proposing the standard two-year recovery period for the Impact for USGAAP Deferral Account. These recovery periods are more appropriate than the suggestion to recover the variance over the balance of the expected average remaining service life of the employees ("EARSL") of 11 to 12 years for the following reasons.[1]

1) ***No relationship exists between the amounts recorded in the Pension and OPEB Cost Variance Account and EARSL.***
   Amounts recorded in this account relate to costs incurred and recognized by OPG in 2011 and 2012, not costs of a future period. There is no basis for linking recovery of these amounts to EARSL, because there is no causal relationship between them and the period during which employees are expected to render future service.

   The costs recorded in the account have an immediate impact on pension/OPEB costs. Absent the error in setting payment amounts for 2011 and 2012, a more accurate forecast of these costs would have already been recovered from ratepayers. The costs recorded in the Pension and OPEB Cost Variance Account are those in the 2011-2012

[1] EARSL of 12 years for pension and 11 years for OPEB. See Ex. A3-1-1, page 93.

period - they are not costs to be deferred and amortized over the remaining average life of employees.

2) ***Recovery over EARSL would be inconsistent with the basis upon which the Pension and OPEB Cost Variance Account was established.***

As noted in Ex. H2-1-3, section 4.1, the OEB specifically approved the variance account as the simplest and most expeditious method of remedying the error related to the rejection in EB-2010-0008 of an updated forecast of pension and OPEB cost for the 2011-2012 period. Therefore, the impact of the error is reflected in the payment amounts received by OPG during 2011 and 2012. Absent the error, an updated forecast of the costs would have already been recovered from ratepayers. OPG notes that similar circumstances led to the establishment of the Tax Loss Variance Account, which has been approved for clearance over 3 years and 10 months.

3) ***Given the relatively small balances in the Impact for USGAAP Deferral Account customer impacts, regulatory consistency and administrative convenience argue against extending recovery for the 11 year duration of EARSL.***

The balance in the Impact for USGAAP Deferral Account relates to amounts that, under CGAAP, would have been amortized into costs, and therefore reflected in revenue requirement, over a future period based on EARSL. Indeed, as discussed at Ex. A3-1-2 at p. 4, line 18 to p. 5, line 10 and in response to L-6-1 Staff-36, this is a key reason why OPG should be allowed to recover these costs.

The projected balance in the Impact for USGAAP Deferral Account is OPG's fifth largest balance in this proceeding and represents less than five per cent (nuclear) and three per cent (regulated hydroelectric) of the total projected balances sought for recovery. OPG's projected nuclear rider would decrease by $0.45 per MWh and the projected hydroelectric rider would decrease by $0.05 per MWh using EARSL as the recovery period for the Impact for USGAAP Account. Thus there would be little customer bill mitigation value resulting from the extended recovery period.

In addition, as discussed below, an 11 year recovery period would be inconsistent with OEB precedent regarding recovery periods for OPG deferral and variance accounts. Finally, the recovery of the balance in this account, which will have no additions once new payments for OPG are established using USGAAP (as follows from discussion in L-6-1 Staff-39) would require tracking and reporting over 11 years, which would be inconsistent with regulatory efficiency. Thus, for reasons of simplicity, practicality and consistency, OPG's proposed two-year recovery period is reasonable.

4) ***Recovery over two to four years is consistent with OPG's historical approach to deferral/variance account cost recovery and mitigation.***

There are many considerations that enter into OPG's recovery proposals. In general, as OPG's payment amounts are established for a two-year test period, the same period is the starting point for recovery proposals. Longer recovery periods may be considered for accounts involving larger account balances, to lessen customer bill impacts.

OPG's current recovery proposal for these accounts is consistent with this approach. The Pension and OPEB Cost Variance Account with its relatively large projected balance has a proposed recovery period of four years. The Impact for USGAAP Deferral Account has a relatively small projected balance and thus the standard two-year recovery period is proposed.

5) Recovering these accounts over EARSL would be inconsistent with past OEB decisions regarding recovery periods for every OPG deferral and variance account. The longest recovery period approved for OPG's deferral and variance accounts has been 3 years 10 months.[2] OPG's proposed four year recovery period is consistent with the longest deferral or variance account recovery period ever approved by the OEB for OPG and helps achieve reasonable customer bill impacts for the overall recovery of the deferral and variance account balances. The 11 to 12 year recovery period suggested by SEC is similar to the 11 year, 9 month period of recovery OPG proposed in EB-2007-0905. In the EB-2007-0905 Decision with Reasons the OEB described this recovery period as "lengthy" and rejected it in favour of a much shorter (3 years, 9 months) recovery period.

Calculations and Projections

Based on the information provided in the pre-filed evidence, OPG estimates that the nuclear and regulated hydroelectric rate riders would be $6.96/MWh and $2.23/MWh respectively, excluding interest and using an estimated recovery period based on EARSL. As EARSL per OPG's 2011 audited consolidated financial statements is 12 years for pension and 11 years for OPEB, a simple average of 11 years and 6 months is the estimated recovery period used in this calculation for the Pension and OPEB Cost Variance Account. The estimated recovery period used for the Impact for USGAAP Deferral Account is 11 years, as the LTD benefit plan is a part of OPEB.

The resulting annual recovery amounts absent interest (i.e., amortization only) for the two accounts and those calculated at Ex. H1-2-1, Table 2 are provided in Chart 1 below.

In calculating both the payment rider and the annual recovery amount in Chart 1 below, OPG interpreted "excluding interest" to mean that no interest amounts are included for post-2012 periods.

[2] EB-2010-0008 approved recovery of the Tax Loss Variance Account from March 1, 2011 to December 31, 2014

Chart 1
Comparison of Recovery Amounts

Annual Recovery Amount ($M)	As Proposed (Ex. H1-2-1 Tables 1 & 2)	As Estimated Based on EARSL
Pension and OPEB Cost Variance Account – Nuclear	83.3	29.0
Pension and OPEB Cost Variance Account – Reg Hydro	4.2	1.5
Impact for USGAAP Deferral Account – Nuclear	28.3	5.2
Impact for USGAAP Deferral Account – Reg Hydro	1.3	0.2

The regulated portions of OPG’s projected 2013 accounting costs for each of pension, OPEB excluding the LTD benefit plan, and the LTD benefit plan under CGAAP and USGAAP, as well as projected 2013 pension plan contributions, OPEB payments excluding the LTD benefit plan, and payments for the LTD benefit plan, are provided in Chart 2 below. The 2013 projections reflect inputs and assumptions that are necessary to make reasonable estimates of the pension and OPEB amounts (see L-2-1 Staff-24, Chart 1).

Chart 2
Projection of Regulated Portion of 2013 Pension and OPEB Amounts[1]

<table>
<tr><th rowspan="2">Amount ($M)</th><th colspan="2">Cost Amounts</th><th colspan="2">Cash Amounts</th></tr>
<tr><th>Hydro electric</th><th>Nuclear</th><th>Hydro electric</th><th>Nuclear</th></tr>
<tr><td>Pension – CGAAP/USGAAP</td><td>17.8</td><td>352.0</td><td>12.3</td><td>242.9</td></tr>
<tr><td>OPEB (excl. LTD) – CGAAP/USGAAP</td><td>10.4</td><td>204.3</td><td>3.4</td><td>65.9</td></tr>
<tr><td>LTD Plan – CGAAP</td><td>1.1</td><td>22.3</td><td rowspan="2">1.1</td><td rowspan="2">22.3</td></tr>
<tr><td>LTD Plan – USGAAP</td><td>1.0</td><td>20.2</td></tr>
</table>

[1] Amounts are presented on the same basis as CGAAP and contribution total amounts those in Tables 1 and 1a in response to L-1-7 SEC-23.

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

SEC Interrogatory #26

Ref: H1/2/1, p. 4

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

Interrogatory

Please explain why the Applicant is proposing to recover the balance in the Bruce Lease Net Revenues Account over four years, rather than over the remaining term of the lease (including the expected extension to 2036). Please calculate the impacts on the hydroelectric and nuclear rate riders proposed (i.e. $2.42 and $8.51) of using the remaining term of the lease including extension. Please provide a table showing the annual amounts recoverable from ratepayers, excluding interest, a) as proposed by the Applicant, and b) based on using the remaining term of the lease including extension.

Response

OPG is proposing a four-year recovery period to mitigate the impacts of recovering this account over the typical two-year recovery period for OPG's deferral and variance accounts. A four-year recovery period is more appropriate than the suggestion to recover the variance over the balance of the expected lease term for the following reasons:

1) ***Recovery over four years is consistent with OPG's historical approach to deferral/variance account cost recovery and mitigation:***
There are many considerations that enter into OPG's recovery proposals. In general, as OPG's payment amounts are established for a two-year test period, the same period is the starting point for recovery proposals. Longer recovery periods may be considered for accounts involving larger account balances, to lessen customer bill impacts. OPG's current recovery proposal is consistent with this approach.

2) ***The proposed annualized recovery amount of Bruce Lease Net Revenues Variance Account is less than the annualized Bruce Lease Net Revenue Variance Account recovery currently reflected in the EB-2010-0008 nuclear payment rider:***
In EB-2010-0008 the OEB approved a recovery of the December 31, 2010 Bruce Lease Net Revenues Variance Account balance of $249.4M over a 22 month period. The annualized recovery is $135.9M. As shown in Ex. H1-1-1 Table 1c, line 20 col. f), the projected account balance is $368.2M. OPG is proposing to recover the actual audited balance over a four year period. The annualized recovery of the projected amount is $92M, or approximately 67 per cent of the current approved annualized recovery amount.

3) ***OPG's proposal is consistent with the recovery horizon for the Bruce Lease derivative reflected in the EB-2010-0008 nuclear payment rider:***

The recovery of the December 31, 2010 account balance was approved over 22 months to December 31, 2012. That balance included the Bruce Lease derivative revenue amounts, which were determined using a December 31, 2014 average end-of-life date for the Bruce B station. As a result, the December 31, 2010 derivative amount was recovered over a period slightly shorter than 50 per cent of the estimated remaining life of the Bruce B units.

OPG's proposed recovery of the December 31, 2012 balance over a four-year period ending December 31, 2016 includes a Bruce Lease derivative revenue variance amount based on a December 31, 2019 end-of life date for the Bruce B units. Therefore, consistent with EB-2010-0008, OPG's proposal will result in the December 31, 2012 derivative amount being recovered over slightly longer than 50 per cent of the estimated remaining life of the Bruce B units.

4) Recovery over the duration of the lease would be inconsistent with past OEB decisions regarding recovery periods for every OPG deferral and variance account:

The longest recovery period approved for OPG's deferral and variance accounts has been 3 years 10 months[1]. The 24 year alternative period of recovery proposed by SEC is over twice as long as the 11 year, 9 month period of recovery OPG proposed in EB-2007-0905 which, as discussed in L-3-7 SEC 25 was considered "lengthy" by the OEB and rejected in favour of a much shorter (3 year, 9 months) recovery period. OPG's proposed four year recovery period is consistent with the longest deferral or variance account recovery period ever approved by the OEB for OPG and helps achieve reasonable customer bill impacts for the overall recovery of the deferral and variance account balances. Finally, OPG notes that in EB-2010-0008, after discussing the impacts of HOEP falling below $30/MWh on supplemental rent, SEC proposed a 3 year, 10 month recovery period for the Bruce Lease Net Revenue Variance Account.[2]

5) The lease term is not a source of <u>any</u> of the variances recorded in the account:

The expected lease term to 2036 is used only to calculate base rent revenue (net of related tax impacts). The lease term assumes post-refurbishment operation of the Bruce A units. As shown in Ex. H1-1-1, Table 14a, line 5, there is no variance associated with base rent revenue and, as noted in L-1-7 SEC-10, the lease term does not factor into the calculation of other revenue or cost items, such as changes in the fair value of the derivative liability or depreciation expense (and, therefore, nuclear waste management and nuclear decommissioning liability impacts).

<u>Calculations</u>

A recovery period of 24 years for the Bruce Lease Net Revenues Variance Account results in a nuclear payment rider of $7.01/MWh excluding interest based on information provided in the pre-filed evidence. There is no impact on the proposed hydroelectric payment rider.

[1] EB-2010-0008 approved recovery of the Tax Loss Variance Account from March 1, 2011 to December 31, 2014

[2] EB-2010-0008, Final Argument of the School Energy Coalition, pages 75-76.

The resulting annual recovery amounts absent interest (i.e., amortization only) for the account and those calculated at Ex. H1-2-1, Table 2 are provided in Chart 1 below.

In calculating both the payment rider and the annual recovery amount in Chart 1 below, OPG interpreted "excluding interest" to mean that no interest amounts are included for post-2012 periods.

Chart 1
Comparison of Recovery Amounts

Annual Recovery Amount ($M)	As Proposed (Ex. H1-2-1 Table 2)	Using Recovery Period to 2036
Bruce Lease Net Revenues Variance Account	92.1	15.3

SEC Interrogatory #27

Ref: H2/1/2, p. 2

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

Interrogatory

Please confirm that nothing in O Reg 53/05 limits the period of time over which the Board can order recovery of Bruce-related costs

Response

Confirmed.

SEC Interrogatory #28

Ref: H1/2/1, p. 4

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

Interrogatory

Please explain the reasons for the delay in filing, i.e. filing an Application for January 1st rate riders on September 24th. Please confirm that the Application does not contemplate the possibility of new rate riders as of January 1st, as the final numbers would not in any case be available until February or later. Please explain why the Applicant did not either a) file earlier and seek new rate riders as of January 1, 2013 based on forecast balances, or b) file later and seek new rate riders effective July 1, 2013 based on actual balances.

Response

Given that this application is for clearance of deferral and variance accounts, as opposed to a full cost of service application, OPG anticipated that this application could be dealt with relatively expeditiously.

As noted in the referenced exhibit, and at Ex. A2-1-2, p.2, OPG's application is for new riders effective January 1, 2013 and OPG has proposed Interim Period Shortfall Riders in recognition that the implementation date will be later than the proposed effective date in order to incorporate actual balances.

While figures in OPG's application reflect projected 2012 balances, OPG's proposal is to use actual audited balances, which are expected to be available in February 2013, to develop the payment amount riders. These figures will be provided in an update. OPG proposed this approach as it is similar to the approach that was accepted by the OEB in EB-2010-0008, as noted at Ex. H1-2-1, p.1.

SEC Interrogatory #29

Ref: H1/2/1, Tables 1 and 2

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

Interrogatory

Please confirm that the Applicant is proposing to collect from ratepayers, in 2013 and 2014, an incremental amount of $963.7 million on 141.6 TWh of forecast production, for an average cost of $6.81/MWh.

Response

OPG proposes to collect amounts consistent with actual audited 2012 account balances. The referenced tables show derivation of account balances and riders based on projected 2012 balances.

OPG confirms that the arithmetic in the question is correct based on the projected 2012 balances.

SEC Interrogatory #30

Ref: H1/3/1, p.5

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

Interrogatory

Please explain the rationale for applying interest to the monthly opening balances of accounts such as the Pension and OPEBs Variance Account or the Bruce Lease Net Revenues Variance Account, when those accounts are made up almost exclusively of non-cash obligations.

Response

OPG records interest in the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account as per the OEB's Decisions and Orders in EB-2011-0090 and EB-2010-0008, respectively, using the OEB-approved generic interest rate methodology for determining carrying charges on outstanding deferral and variance account balances.

The general basis for recording interest is the incidence of over or under-collection by the utility, not the nature of the item that has been over or under-collected. The approved balances in the above accounts represent differences between the amount of OEB-approved forecast costs (or net revenues) collected (or repaid) by OPG and such approved actual amounts as determined on the same basis as the forecast amounts. It is appropriate that such differences attract interest.

SEC Interrogatory #31

Ref: L/1/1, Staff 14

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

Interrogatory

Please provide the Applicant's forward cash flow analysis to demonstrate, with respect to the proposed recovery of the Pension/OPEB account, that "such recovery is necessary to ensure that OPG has adequate cash resources for financial sustainability".

Response

While the question references a statement in OPG's response to Board Staff interrogatory L-1-1 Staff-14 regarding the Pension and OPEB Cost Variance Account, the statement was made in the context of all Board Staff interrogatories that, in aggregate, suggested delaying the clearance of a significant portion of OPG's account balances. Specifically, in addition to L-1-1 Staff-14, L-1-1 Staff-13 suggested that the review of the Bruce Lease Net Revenues Variance Account could be set aside until a future proceeding, while L-6-1 Staff-31 suggested deferring OPG's request to adopt USGAAP for regulatory purposes, thereby also deferring the recovery of the Impact for USGAAP Deferral Account. As detailed below, the cited statement by OPG reflected a concern that significant cash flow reductions from any delays in the recovery of account balances would negatively impact financial sustainability, particularly in the context of a negative outlook on OPG's credit rating issued in Standard & Poor's Rating Services ("S&P") Research Update dated November 27, 2012 (the "Outlook"). The Outlook report is provided in Attachment 1 to this response.

OPG's pre-filed evidence indicates that the above three accounts have projected 2012 year-end balances totaling over $750M.[1] This represents approximately 60 per cent of the total projected balances of approximately $1.3 billion. Delaying the recovery of these balances would significantly reduce OPG's cash flows and unfavourably impact related financial metrics. For the three accounts mentioned, the total of the projected annual recovery amounts is in excess of $200M[2] (over 40 per cent of the total proposed annual recovery amounts for all accounts of approximately $480M).

A key measure used by OPG and assessed by credit rating agencies in evaluating cash flow adequacy is Funds from Operations ("FFO") Interest Coverage, which has been disclosed by OPG throughout 2012 in its Management's Discussion and Analysis ("MD&A") as part of quarterly financial results.[3] As can be seen from these documents, this measure, as

[1] Ex. H1-2-1, Table 1, lines 8 and 9, col. (b) + Ex. H1-2-1, Table 2, lines 5, 8 and 9, col. (b) total $777.4M
[2] Ex. H1-2-1, Table 1, lines 8 and 9, col. (d) and Ex. H1-2-1, Table 2, lines 5, 8 and 9 col. (d) total $209.2M
[3] Calculation and discussion of the FFO Interest Coverage measure are found as follows:
pp. 12, 22, 27 and 28 of OPG's Q1 2012 MD&A at http://www.opg.com/investor/pdf/2012_Q1_MDA.pdf

calculated over a rolling 12-month period, has deteriorated during 2012, from 3.1 for the 12 months ended December 31, 2011 to 2.8 for the 12 months ended September 30, 2012. An FFO Interest Coverage ratio of below 3.0 times is considered to be unfavourable, as, for example, noted in the Outlook, which states "[…] we believe that the SACP [stand-alone credit profile] could be lowered if we expect OPG's […] adjusted FFO interest coverage weakens to below 3.0x." (Attachment 1, p. 5)

A reduction of $200M per year in deferral and variance account recoveries is significant, both in absolute terms and in terms of the relative impact on FFO Interest Coverage. OPG estimates that such a reduction would decrease FFO Interest Coverage by approximately 0.5. Given that the measure has already deteriorated to below 3.0 at September 30, 2012, OPG is concerned with the impacts of any delay in recovering a significant portion of 2012 account balances on the assessment of OPG's credit worthiness and ability to meet its obligations by credit rating agencies.

OPG's concerns were reaffirmed by the above-noted S&P release lowering the credit rating outlook for OPG from "Stable" to "Negative". The Outlook was issued subsequent to the commencement of the public hearing process for this proceeding. If the recovery of the balances is deferred, OPG will be required to increase borrowings and incur additional interest costs, thus negatively impacting cash flow metrics and leading to a higher risk of a credit rating downgrade. Such a downgrade will negatively impact OPG's cost of funding and financial sustainability.

Specifically, the Outlook notes that "unfavourable rate decisions" could negatively impact FFO interest coverage and adjusted FFO-to-total debt measures, thereby lowering the SACP, which would, in turn, result in a downgrade (Attachment 1, p. 5). The Outlook also specifically notes that: "stress on financial metrics" could be caused by the timing difference between the incurrence of costs and the start of cash inflows related to these costs as a result of regulatory approval (Attachment 1, p. 3). While this statement was made by S&P in the context of recovery of costs for capital projects, it would apply equally to a lag in clearing deferral and variance accounts. Coupled with OPG's proposal for a longer recovery period of four years for the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account in order to lessen ratepayer impact (as discussed in L-3-4 CCC-08, L-3-7 SEC-25 and L-3-7 SEC-26), this further underscores the material risks to OPG's financial sustainability of not clearing the balances on a timely basis.

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pp. 13, 24, 30, 31 of OPG's Q2 2012 MD&A at http://www.opg.com/investor/pdf/2012_Q2_FullRpt.pdf
pp. 14, 25, 32, 33 of OPG's Q3 2012 MD&A at
http://www.opg.com/investor/pdf/Q3%202012%20Full%20Report_FINAL.pdf

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Standard & Poor's Research

Research Update:

Ontario Power Generation Inc. Outlook Revised To Negative From Stable On Growth Plan Stresses; 'A-' Ratings Affirmed

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Research Update:

Ontario Power Generation Inc. Outlook Revised To Negative From Stable On Growth Plan Stresses; 'A-' Ratings Affirmed

Overview

- We are revising our outlook on Ontario Power Generation Inc. (OPG) to negative from stable.
- At the same time, we are affirming our ratings, including our 'A-' long-term corporate credit rating, on the company.
- The outlook revision reflects the revision of our stand-alone credit profile on OPG to 'bbb-' from 'bbb'.
- The ratings reflect our opinion of the company's strong business risk profile and significant financial risk profile.

Rating Action

On Nov. 27, 2012, Standard & Poor's Ratings Services revised its outlook on Ontario Power Generation Inc. (OPG) to negative from stable. At the same time, Standard & Poor's affirmed its ratings, including its 'A-' long-term corporate credit rating, on the company.

The outlook revision reflects the revision of our stand-alone credit profile (SACP) to 'bbb-' from 'bbb'. Based on our criteria for government-related entities, based on a 'bbb-' SACP and a "high" probability of extraordinary government support, the negative outlook reflects the negative outlook on the utility's shareholder, the Province of Ontario (AA-/Negative/A-1+). A further lowering of the SACP or a downgrade on the province would lead to a negative rating action on OPG.

Rationale

The SACP revision reflects our view that OPG's credit metrics could weaken in the near-to-medium term. The company is continuing with a number of projects that require a significant amount of capital expenditure in the next two years. In particular, we forecast that the Darlington nuclear facility refurbishment together with the Lower Mattagami project will require approximately C$1 billion in capital expenditures in each of the next two years. This is in addition to the other projects that OPG is working on along with sustaining capital expenditure.

We view this capital expenditure in a regulatory context, which provides limited cash flow relief during construction for multiyear projects and a balanced-but measured-perspective on yearly rate applications. Accordingly, the timing difference between the regulatory asset's development (with the consequential debt) and the start of cash flow in the regulatory environment (which has allowed moderate rate increases) could stress financial metrics.

The ratings on OPG, which Ontario owns, reflect Standard & Poor's opinion of the regulatory oversight of the utility's baseload nuclear and hydroelectric assets; a diverse generation portfolio; and dominant market position in Ontario. Weak cash flow metrics and exposure to regulatory delay and cost overruns related to new construction and refurbishment of existing facilities offset the company's credit strengths, in our view. Exposure to merchant electricity prices and volume related to OPG's unregulated business further constrain the SACP. We rate management as "fair" under our management and governance criteria. The company borrows about 80% of its C$4.9 billion reported consolidated debt as of Sept. 30, 2012, from the government shareholder, through Ontario Electricity Financial Corp. (OEFC).

We base the 'A-' rating on OPG's SACP, which we assess at 'bbb-', and our opinion that the ratings on OPG and Ontario are linked. We assess that there is a "high" likelihood that the government shareholder would provide timely and sufficient extraordinary support in the event of financial distress. This reflects our views that OPG's role is "important" to Ontario, that the utility plays a major role in the government's energy policy; and that the link between the utility and the province is "very strong", reflecting ownership relationship, ongoing financial support from OEFC, and the province's strong influence in the company's investment decisions.

In our view, OPG's business risk profile benefits from having about 77% of its EBITDA in 2011 supported by regulated sources. These sources include nuclear and baseload hydroelectric assets that the Ontario Energy Board (OEB) regulates as well as regulated nuclear waste management. Assurance of cost recovery and a predictable, albeit moderate, return for these assets is a positive credit factor. Historically, although the OEB decisions have led to more moderate returns for OPG, given the discretion that the company has with respect to its capital expenditure and the resultant level of debt it was able to mitigate the impact of lower revenues. However, the company has reached an inflection point in its capital plans where significant expenditures for such things as the Darlington facility refurbishment and the Lower Mattagami project are required. We believe that these projects will put significant strain on credit metrics for the next two years.

The fuel diversity and large number of generating units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance its business position, in our opinion. As of Sept. 30, 2012, the portfolio of assets that the company owns and operates includes:

- 6,606 megawatts (MW) of baseload regulated nuclear generation;
- 6,996 MW of predominantly run-of-the-river hydroelectric generation, of which 3,312 MW is regulated; and
- 5,447 MW of intermediate unregulated thermal generation (projected to shut down by 2014).

We believe OPG has a strong competitive position. The company dominates the Ontario electricity market, producing 85 terawatt-hours (TWh; most of it baseload) of the 142 TWh of electricity consumption in the province in 2011. Its unregulated hydro assets typically enjoy a competitive advantage compared with higher marginal cost gas-fired alternatives.

Constraining OPG's unregulated cash flows, in our view, are the company's exposure to the wholesale electricity price and volume risk due to fluctuations in Ontario demand, the inherent uncertainty of available water flows, and competitively priced imports from neighboring markets. Wholesale electricity prices have struggled in 2012, with the weighted average Hourly Ontario Electricity Price at C$24 per MW-hour (MWh) for the nine months ended Sept. 30, 2012, compared with the C$32 per MWh in 2011.

Technical challenges associated with key components of nuclear facilities have the potential to expose the units to lengthy outages, hurting cash flow performance and increasing capital demands. OPG's nuclear liability risk-sharing agreement with Ontario limits the company's used nuclear fuel liabilities and partially mitigates the operating challenges.

In implementing its energy policy favoring renewable energy generation to replace the less eco-friendly coal-fired generation facilities, the province has directed OPG toward investments in projects on various occasions. It also required the utility to shut down the remaining coal-fired plants by 2014. Along with these directives, the government has provided ongoing support to OPG through loans from OEFC and long-term power purchase agreements with the Ontario Power Authority to support the company's other projects. It also provides OPG with a contingency support agreement to cover operating costs and a modest return on investments of the coal-fired facilities until complete closure in 2014. We regard these ongoing supports as important mitigating factors to the company's business risk profile.

We believe OPG's stand-alone financial risk profile is significant. We believe stand-alone cash flow metrics are generally weak, partially as a result of the material postretirement benefit adjustments and modest return on investments. Adjusted funds from operations (AFFO) interest coverage was 2.7x and FFO-to-total debt was 9.1% for the 12 months ended Sept. 30, 2012. AFFO, in our definition, deducts the contribution to nuclear waste and decommissioning funds, which we regard as a cost of ongoing operations. We expect any improving trend that might emerge in the next three years to be gradual. We forecast that AFFO for the next two years will be approximately C$800 million in each of the next two years. Based on the significant capital expenditure required, we believe that AFFO-to-debt could fall below 9% in each of the next two years.

Liquidity

OPG's liquidity is adequate under our criteria, and should be sufficient to cover cash uses in the next 12 months. Standard & Poor's bases its liquidity assessment on the following factors and assumptions:

- We expect that the company's liquidity sources of about C$2.9 billion in the next 12-18 months will exceed its uses by about 1.6x.
- Available cash resources include our expectation of annual cash flow from operations of about C$900 million, and available credit facilities of C$1.9 billion as of Sept. 30, 2012. The committed and available credit facilities comprise a C$1 billion maturing May 2017, a C$700 million bank credit facility to support initial construction of the Lower Mattagami project, and a C$700 million OEFC facility for Lower Mattagami.
- Projected uses of cash in the next 12 months include a sizable capital expenditure of about C$1.7 billion.

We expect that the utility will not pay out dividends in the foreseeable future and future debt maturities do not present a material concern, given the shareholder's practice of refinancing notes payable at their due dates.

Outlook

The negative outlook reflects our view of the 'bbb-' SACP, the high likelihood of provincial support, and the negative outlook on the province. Although we recognize that OPG's cash flow adequacy will be weaker in the next two years due to substantial capital expenditure on regulated and contracted projects, we believe that the SACP could be lowered if we expect OPG's adjusted FFO-to-total debt to stay below 8%-10% or adjusted FFO interest coverage weakens to below 3.0x. This could result from unfavorable rate decisions, operational issues resulting in unexpected outages in its generation facilities, or a move toward a more aggressive financial policy (including extended significant debt financed capital expenditure). A decline in the SACP to 'bb+' would result in a downgrade on OPG.

For the SACP to move a notch higher, we believe OPG would need to improve significantly the level and stability of is overall cash flow strength comfortably above 10%-12%. This could result from an equity injection from the province which we consider to be highly unlikely. It could also result from some form of additional regulatory cash flow support during the upcoming period of high capital spending on large projects that we have seen for other Canadian utilities in a similar position.

We link the ratings on the utility and those on the province through our enhanced government-related entity methodology. All else being equal, a one-notch downgrade to Ontario would result in a one-notch downgrade in OPG. An outlook revision to stable on the province could result in a similar outlook revision on OPG. A change in the relationship with the government shareholder, which includes changes in ownership, could move the ratings in either direction.

Related Criteria And Research

- Methodology: Management and Governance Credit Factors for Corporate Entities and Insurers, Nov. 13, 2012
- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Ratios And Adjustments, April 15, 2008

Ratings List

Ontario Power Generation Inc.

	To	From
Outlook Revised To Negative		
Corporate credit rating	A-/Negative/--	A-/Stable/--
Ratings Affirmed		
Commercial paper		
Canada scale	A-1(Low)	

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Board Staff Interrogatory #29

Ref: Exh H2-1-3 page 8

Issue Number: 4
Issue: Is the proposed continuation of the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order appropriate?

Interrogatory

The pre-filed evidence indicates that 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.

When does OPG plan to file a cost of service application(s) for its next payment amounts order(s) for hydroelectric and/or nuclear prescribed assets and what years would the payment order(s) be in effect for?

Response

OPG currently plans to file an application with the OEB in 2013 for new regulated prices for production from OPG's regulated hydroelectric facilities to be effective in 2014 for the 2014/2015 period. OPG continues to consider the timing and approach for a rate application for production from its regulated nuclear facilities.

Board Staff Interrogatory #30

Ref: Exh H2-1-3 page 11

Issue Number: 4
Issue: Is the proposed continuation of the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order appropriate?

Interrogatory

Mark Carney, Governor of the Bank of Canada, in a Monetary Policy Report news conference on October 24, 2012 stated that "over time, rates are more likely to go up than not."

Does OPG support the continuation of this variance account in the longer term in recognition that discount rates are more likely than not to increase in the future, so that any benefits accruing to ratepayers (not reflected in the future test years' revenue requirements) can be attributed to ratepayers in the future? If not, please provide the reasons and what year should be the sunset for this variance account.

Response

OPG supports continuation of this variance account. This support is not dependent on the anticipated direction of future discount rate movements.

Energy Probe Interrogatory #03

Ref: Exhibit H1, Tab 2, Schedule 1, p.3 of 5

Issue Number: 4
Issue: Is the proposed continuation of Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order appropriate?

Interrogatory

Regarding recovery of hydroelectric deferral and variance accounts, the balance in the Pension and OPEB Cost Variance Account will be amortized over an extended period to lessen the ratepayer impact.

a) If the yearend balance in this account attracts an annual interest or carrying cost amount, how is the ratepayer impact lessened?

b) Doesn't the interest/carrying cost offset the time value benefit of the longer amortization period?

Response

a) 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 was chosen to lessen the impact on monthly ratepayer bills as compared to a 24-month amortization period.

b) The purpose of the 48-month amortization is to lessen the impact on monthly ratepayer bills, not to minimize the total amount paid by ratepayers over that period. However, conceptually, the interest on the unamortized balance in the account is offset by the time value of money. If both ratepayers and OPG were to use the OEB's prescribed interest rate on the variance account as the discount rate for their analyses, they should be essentially indifferent to the recovery period on a net present value basis. In reality, however, the prescribed interest rate of Bankers' Acceptances three-month rate plus a spread of 25-basis points for deferral and variance accounts (currently 1.47%) is likely to be significantly lower than a typical consumer's cost of borrowing. Thus considering a typical consumer's time value of money, most customers would likely be better off under the proposed 48-month amortization.

SEC Interrogatory #32

Ref: H2/1/3, p. 1

Issue Number: 4
Issue: Is the proposed continuation of Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order appropriate?

Interrogatory

Please provide the Applicant's most current long term forecast of interest and discount rates, i.e. the forecast currently in use for strategic planning or similar purposes.

Response

OPG does not use a single general assumption for long-term interest or discount rates for "strategic planning or similar purposes." Instead, each rate is specific to the particular purpose or analysis for which it is used and reflects the nature of the calculations and any applicable accounting, actuarial, or regulatory requirements. Some examples are provided in the following paragraphs.

For the purposes of projecting interest costs for new 10-year long-term debt in 2013, OPG has used an average interest rate of 4.7 per cent. The rate is based on an average forecast Government of Canada bond yield plus a credit risk spread for OPG. This forecasting methodology was also discussed in EB-2010-0008, Ex. C1-1-2, section 4.2.

OPG uses a discount rate that reflects its weighted average cost of capital rate (rather than a rate based solely on interest rates) to evaluate potential investments related to its prescribed facilities. For this purpose, OPG currently uses a long-term discount rate of seven per cent.

As noted in response to interrogatory L-2-1 Staff-24 (c), OPG does not forecast the pension and OPEB discount rates. The projections of OPG's pension and OPEB costs are derived using the long-term discount rates determined in accordance with USGAAP and CGAAP based on actual bond yields in existence at the time the projection is prepared. These discount rates are provided by an independent actuary. Exhibit H2-1-3, page 11 and the response to interrogatory L-2-1 Staff 24 (d) show the long term discount rates used in calculating OPG's projected 2013 pension and OPEB costs as presented in the pre-filed evidence. OPG will file an update to its evidence in February 2013, which will include the actual discount rates as of the end of 2012 as well as 2013 pension and OPEB costs based on these rates.

In summary, OPG uses a variety of forward-looking interest or discount rates for different purposes. Rates are selected to be suitable for a specific purpose and meet any applicable requirements, and are thus not suitable for other uses.

AMPCO Interrogatory #17

Ref: Exhibit H1-1-1 Page 11 Lines 9-12

Issue Number: 5
Issue: Is the proposed continuation of other deferral and variance accounts appropriate?

Interrogatory

Preamble: As a reason for deferring the clearance of the HIM and SBG Accounts, OPG states that the review of the balances in the HIM and SBG Accounts will require the results of analysis that was ordered by the OEB and that OPG is undertaking with respect to the operation of the Sir Adam Beck PGS, how these operations affect SBG and the interaction between SBG and HIM.

a) What is the status and expected completion date of this analysis?

Response

In its Decision with Reasons for EB-2010-0008, the Board directed OPG to provide a more comprehensive analysis of the benefits, among other things, of the Hydro Incentive Mechanism ("HIM") for ratepayers and the interaction between this mechanism and surplus base load generation ("SBG"). This study is ongoing and will be complete by the time OPG files its next payment amounts application for its prescribed hydroelectric facilities. OPG currently plans to make such an application in 2013.

CCC Interrogatory #09

Ref: Ex. H1/T3/S1

Issue Number: 5
Issue: Is the proposed continuation of other deferral and variance accounts appropriate?

Interrogatory

The evidence sets out a summary of the continuing deferral and variance accounts and the basis for making entries into those accounts after December 31, 2012. Please describe any changes made relative to what has been previously approved by the OEB with respect to making entries.

Response

After December 31, 2012, OPG will continue to record amounts, including interest, into the continuing deferral and variance accounts in accordance with the applicable OEB decisions and orders and *Ontario Regulation 53/05*. Where appropriate, based on the nature of the authorized account, OPG will continue to record differences relative to forecast reference amounts underpinning the EB-2010-0008 approved revenue requirement. The bases for entries into the relevant accounts for periods after December 31, 2012 as set out in Ex. H1-3-1 follow the methods approved by the OEB in EB-2009-0174 for periods after December 31, 2009, which were applied by OPG for entries made up to March 1, 2011 and reflected in the December 31, 2010 balances approved for recovery in EB-2010-0008.

Board Staff Interrogatory #31

Ref: Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (EB-2008-0408)
Exh A3-2-2

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

Interrogatory

Issue 4 of the Addendum is "Should the Board permit rate applications or RRR reporting under USGAAP?" At page 19 of the Addendum, it states:

> However, the Board must consider the general public interest in ensuring efficiency and consistency in utility regulation in Ontario, and will require utilities to explain the use of an accounting standard other than MIFRS for regulatory purposes.
>
> A utility, in its **first cost of service application following the adoption of the new accounting standard** [emphasis added], 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 the standard from the appropriate Canadian securities regulator (if applicable) showing any conditions or limitations, and set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

Please explain why OPG's request for approval to adopt USGAAP for regulatory purposes is not part of a cost of service application, where detailed information on all potential accounting changes and the associated quantifiable impacts could be fully examined and assessed.

Response

OPG's evidence states that it is applying to use USGAAP for regulatory accounting, reporting and rate-making purposes to avoid keeping multiple sets of financial records (Ex. A3-1-2, page 2). As discussed in Ex L6-1-Staff 38 b), OPG has applied to use USGAAP in this application in order to get a decision on the method that the OEB will accept for regulatory accounting, reporting and ratemaking purposes so that any subsequent applications can be made on that basis.

OPG has provided evidence on accounting differences between CGAAP and USGAAP. OPG would provide the same evidence in a cost of service proceeding; therefore, there is no compelling reason to defer consideration of this issue to a cost of service hearing.

Further, the fact that the OEB has identified it as an issue in the current proceeding is evidence that the OEB believes that it is possible to consider this issue outside a cost of service proceeding. This is consistent with the fact that the OEB has approved the use of USGAAP for Hydro One Distribution (EB-2011-0399 Decision and Order issued March 23, 2012) based on a stand-alone application filed for this purpose rather than through a cost of service proceeding.

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.

Board Staff Interrogatory #33

Ref: Exh A3-1-2, pages 8-9

Issue Number: 6

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

Interrogatory

OPG has indicated if it had adopted IFRS there would have been several changes under IFRS including pension and OPEB plans and nuclear liabilities which would introduce additional volatility. This includes additional impacts for 2012 based on the actuarial gains and losses and past service costs arising during that year which would be charged to and remain in AOCI. As at the end of 2012, OPG projected the cumulative impact of the changes to be close to $3.9 billion on a pre-tax basis.

a) If OPG had adopted IFRS in 2012 rather than USGAAP, what would the financial impact be on pension expense for 2012 and 2013 arising from the cumulative impact of the changes of close to $3.9 billion referenced above and financial impact on the variable costs being expensed immediately in 2012 and 2013?

b) Are there other quantifiable financial impacts from an adoption of IFRS for 2013 that can be identified?

Response

OPG must adhere to USGAAP rules and maintain USGAAP financial records starting January 1, 2012, as required by O. Reg. 395/11 under the *Financial Administration Act*. OPG discontinued IFRS conversion work in late 2011 and focused all efforts on conversion to USGAAP given the short amount of time available to accommodate USGAAP adoption.

While OPG does keep apprised of significant IFRS developments, such as new IFRS guidance, OPG does not do so in sufficient detail to enable the evaluation of specific current or possible future transactions under IFRS.

OPG does not generate or maintain current financial records or forecast information presenting the impacts of IFRS on 2011 or subsequent year transactions. This includes not having available 2011 IFRS impacts using 2011 actual financial results as requested in Ex. L-6-1 Staff-40. The discontinued IFRS work included work associated with the finalization and audits of the restatement of 2011 transactions under IFRS (partly because the 2011 fiscal year had not concluded when IFRS work was curtailed), finalization of financial planning information under IFRS for subsequent years, and preparation of financial statements under IFRS.

An extensive amount of work requiring numerous assumptions would be necessary to estimate IFRS impacts using current information, as OPG's IFRS conversion project would need to be restarted. This would be impractical and could not be completed within a reasonable timeframe.

In any event, the IFRS work that OPG had begun would no longer be accurate because it presumed an IFRS adoption date of January 1, 2012 (with an opening balance sheet as at January 1, 2011). Given that OPG's financial reporting must be under USGAAP commencing January 1, 2012, OPG could not have adopted IFRS for financial reporting purposes as of that date.

Any future consideration of IFRS for financial reporting purposes necessarily would be based on a later adoption date, which would create different impacts, including differences arising from any changes to IFRS guidance related to initial adoption. Should OPG be required to use IFRS for regulatory purposes starting on January 1, 2012, the different adoption dates would mean that OPG's regulatory and financial reporting would be permanently out of step with each other even if at some future point OPG is required to adopt IFRS for financial reporting purposes.

In summary, while OPG is providing some high level IFRS information on financial impacts in order to assist the OEB in reaching a decision on OPG's application to adopt USGAAP for regulatory purposes, it notes that actual amounts could be very different if OPG were required to adopt IFRS in the future. OPG provided estimated, order-of-magnitude impacts of adopting amended International Accounting Standard 19 ("IAS 19") in its pre-filed evidence because this amount can be estimated with reasonable certainty.

a) The impact on variable (and other) costs associated with nuclear liabilities is discussed in Ex. L-6-1-Staff 40 b) and d). The requested impact on pension and OPEB is discussed below.

   As noted in Ex. A3-1-2, pp. 7-8, the pre-filed evidence provided a pre-tax estimate of close to $3.9 billion as the cumulative impact of recognizing, as a component of equity, all previously unamortized actuarial gains and losses and past service costs related to pension and OPEB as of the end of 2012 based on the mandatory adoption of IAS 19. This permanent recognition of all previously unamortized non-LTD pension and OPEB amounts as of the end of 2012 in a component of equity would eliminate the amortization component of pension and OPEB costs under IFRS in subsequent years.

   Under CGAAP (and USGAAP), the amortization of the $3.9 billion amount would have been included in future revenue requirements and recovered through the setting of future payment amounts. OPG would therefore seek recovery of these amounts to avoid the very substantial, financial harm that would otherwise result from the implementation of a new accounting basis, consistent with the OEB's principles governing the transition to a different regulatory accounting basis, including fairness. As noted in Ex A3-1-2 p. 8, OPG would seek approval of deferral account(s) ("IFRS deferral account"), to be effective January 1, 2012, in order to recover and moderate the above impacts, as it did in making its EB-2011-0432 application to recover or refund the financial impacts of adopting USGAAP.

To properly estimate the financial impact of IFRS in relation to the projected $3.9 billion impact, OPG considers the amortization of the IFRS deferral account balance that it would request to commence effective January 1, 2013 – the same date proposed in this Application for starting the recovery of the Impact for USGAAP Deferral Account. Consistent with the costs giving rise to the impacts, OPG would propose the recovery period for the IFRS deferral account would be based on the expected average remaining service life ("EARSL") for OPG's employees of 12 years. This figure is reflected in the calculation of OPG's 2011 pension costs as reported in its 2011 audited annual consolidated financial statements at Ex. A3-1-1, Attachment 1, p. 93. The resulting amortization amount would be approximately $325M annually, on a pre-tax basis.

Under USGAAP, OPG's revenue requirement would continue to reflect the non-LTD portion of these amounts as they are first charged to AOCI and then amortized over time as a component of pension and OPEB costs. Based on projections used in the pre-filed evidence, the amount of this amortization is expected to be approximately $200M annually, on a pre-tax basis.

The net financial impact of the above is an estimated additional $125M to be recovered annually from customers. To eliminate this impact, the recovery of the IFRS deferral account would have to be extended from EARSL (12 years) to 20 years.

In addition, the application of amended IAS 19 would also result in an increase in the component of pension costs equivalent to the net of interest cost and the expected return on pension plan assets components under USGAAP and CGAAP. This increase would need to be included in revenue requirement and therefore create additional impacts to be recovered by OPG.

For 2012, based on projections used in the pre-filed evidence and using the same logic and assumptions above, OPG's USGAAP pension and OPEB period costs for the regulated business include approximately $150M for amortization of actuarial gains and losses and past service costs. While this amount would not be included in an estimate of 2012 IFRS period costs, it has been included by OPG as a reduction in arriving at the estimated $3.9 billion estimated impact that would need to be recovered from ratepayers.

b) Additional 2013 impacts on OPG's regulatory accounting with respect to nuclear liabilities are discussed in response to Ex. L-6-1 Staff-40 (b) and (d). Other than these additional impacts and the tax impacts associated with all nuclear liability and pension and OPEB-related impacts, the only other impact on regulatory accounting identified by OPG as part of the discontinued IFRS conversion project relates to accounting for Bruce Lease base rent revenue. This impact was estimated to be the same as that under USGAAP as discussed in Ex. A3-1-2, section 4.2.2.

Potential regulatory accounting *presentation* impacts arising from possible financial statement presentation changes that may result from reclassification between line items on OPG's income statement, balance sheet or statement of comprehensive income under IFRS are not considered because OPG did not complete the development of IFRS financial statements as noted above. These items would not impact revenue requirement.

Board Staff Interrogatory #34

Ref: OPG Application for USGAAP Deferral Account (EB-2011-0432)
Exh H1-1-1 pages 8-9

Issue Number: 6

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

Interrogatory

In the decision in proceeding EB-2011-0432, issued on March 2, 2012, the Board approved the establishment of the Impact for USGAAP Deferral Account. At page 5 of the decision, it states that:

> • The approval of the establishment of the deferral account should not be considered to be in any manner or degree whatsoever predictive of disposition of the account; and
>
> • Approval of the establishment of the deferral account should not be considered to be predictive in any manner or degree whatsoever of the Board's determination with respect to the adoption of USGAAP for regulatory accounting purposes in OPG's next payment amounts application.

The extent to which any of the amounts captured in this account would be subject to carrying charges will be determined by the panel deciding the next payments case. [emphasis added]

a) In the event that the Board does not approve the adoption of USGAAP for regulatory purposes in the current proceeding, please confirm that the Impact for USGAAP Deferral Account would not be eligible for clearance in the current proceeding.

b) At pages 8-9 of Exh H1-1-1, OPG states that it proposes to record an estimated $0.8M of interest for 2012 on the balance in this account. Please explain why the balance in this account would be subject to carrying charges. Please explain why OPG is seeking a determination on carrying charges in the current application and not in a future payment amounts proceeding.

c) Please provide references to previous proceedings and any further information to support the allocation of amounts between regulated hydroelectric and nuclear in the Impact for USGAAP Deferral Account.

Response

a) Confirmed.

b) OPG has followed the direction provided by the Board in EB-2007-0905, p. 131 directing OPG "to accrue interest on deferral and variance account balances after March 2008 using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy." The OEB's interest rate policy was applied to all deferral and variance accounts in setting OPG's EB-2007-0905 payment amounts.

In the EB-2010-0008 Decision with Reasons (p. 126) the Board noted that "Interest on the accounts has been applied in accordance with the rates prescribed by the Board from time to time". Interest was applied to all accounts and no findings were made in EB-2010-0008 to impact the application of interest to these accounts.

The EB-2011-0432 Decision and Order, page 5 establishes the Impact for USGAAP Deferral Account effective from January 1, 2012. Once a deferral or variance account has been approved by the Board, OPG accrues interest pursuant to the OEB's interest rate policy, unless the Board has determined otherwise.

Interest cost on the underlying balance is incurred as a result of the accumulation of amounts in the account. Cost causality would suggest that as the interest is directly incurred as a result of the accumulation of the underlying balance, it should be recovered in conjunction with the recovery of the underlying balance. OPG can see no reason why interest recovery should be deferred to a subsequent proceeding.

c) The entries into the Impact for USGAAP Deferral Account calculated on the basis of differences in long-term disability benefit plan costs for 2011 and 2012 reflect the assignment of these costs to each of regulated hydroelectric and nuclear using the methodology approved in EB-2010-0008 as referenced in response to interrogatory L-1-1 Staff-14.

The entry related to long-term disability benefit plan costs recognized in the opening USGAAP balance sheet ($31.4M per Ex. A3-1-2, p. 4) has been allocated to each of regulated hydroelectric and nuclear using the same labour-related allocation factors used to allocate pension and OPEB assets/liabilities reported on OPG's balance sheet The allocation methodology is described in both EB-2012-0002 (Ex. A3-1-1 Attachment 2, p. 36) and in EB-2010-0008 (Ex. A2-1-1, Attachment 3, p. 37).

The regulatory tax impact recorded in the account associated with the above entries is calculated for regulated hydroelectric and nuclear separately based on the attribution of costs described above. Interest amounts were calculated for regulated hydroelectric and nuclear separately, at the OEB's approved interest rate, based on the after tax amounts attributed to each business.

Board Staff Interrogatory #35

Ref: Exh A3-1-2 Attachment 3 Page 5

Issue Number: 6

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

Interrogatory

The 2011 Actuarial Report stated:

> Transition
>
> Upon transition at January 1, 2011, the net benefit asset (liability) in respect of each of the plans must be adjusted to reflect each plan's funded status, with corresponding adjustments to AOCI.
>
> For the LTD [long-term disability benefits] plan, all unrecognized past service costs and unrecognized net actuarial gains and losses under Canadian GAAP must be recognized immediately upon transition [to USGAAP] at January 1, 2011, with a corresponding adjustment to retained earnings.

Based on the above statements, the LTD benefits plan for 2011 was recorded in retained earnings under USGAAP. This resulted in a $39.6M adjustment to retained earnings in 2011 of which $31.4M was allocated to the regulated business and recorded in the USGAAP Deferral Account in 2012 according to H1-1-1 Table 6.

a) Please provide the specific accounting guidance under USGAAP that provides for this accounting treatment specifically for the LTD benefits plan to reflect LTD related unrecognized past service costs and actuarial gain or loss in net income (or retained earnings) but not in AOCI.

b) Please indicate where the LTD benefits plan adjustments are reflected in the Q2-2012 MD&A and financial statements, and particularly in Note 18 US GAAP Transition, posted on OPG's website at the following link: http://www.opg.com/investor/pdf/2012_Q2_FullRpt.pdf

c) What is the estimated annual impact arising from this treatment change to LTD benefits on go forward basis for financial accounting and revenue requirement purposes?

Response

a) Accounting Standards Codification Topic 712, *Compensation – Nonretirement Postemployment Benefits*, paragraph 712-10-25-5, directs that the costs of nonretirement post employment benefits that do not vest or accumulate should be recognized immediately into income. OPG's long-term disability benefit plan falls into this category of benefits and therefore must be accounted for in accordance with this paragraph.

b) Since the LTD benefit plan cost adjustments related to the second quarter and six months ended June 30, 2011 rounded to less than $1M, they were not explicitly disclosed in OPG's Q2 2012 MD&A or financial statements. The Q2 2012 financial statements also do not contain the transitional adjustment calculated as at January 1, 2011 or the full year 2011 impact, as these adjustments were previously disclosed in Note 18 to OPG's Q1 2012 financial statements, posted on OPG's website at the following link:
http://www.opg.com/investor/pdf/2012_Q1_FullRpt.pdf

Specifically, the "Reconciliation of Shareholder's Equity as Previously Reported under Canadian GAAP to USGAAP" in Note 18 to the Q1 2012 financial statements shows a reduction in Retained Earnings of $40M (rounded from $39.6M), which is referenced in Note A under "Notes to Transitional Adjustments" in Note 18.

The $11M OPG-wide impact related to the restated 2011 costs referenced in Note A is included as a component of the total amount in the Effect of Transition to USGAAP column under the Operations, Maintenance and Administration expense line item in the "Reconciliation of the Consolidated Statement of Income from Canadian GAAP to USGAAP for the year ended December 31, 2011" presented in Note 18 to the Q1 2012 financial statements. Of the $11M adjustment, $9.3M is attributed to regulated operations and was recorded in the Impact for USGAAP Deferral Account (Ex. A3-1-2, Chart 1, line 2).

c) Based on assumptions used in the preparation of the evidence, the estimated 2013 financial impact on OPG's regulated operations arising from the change in the accounting treatment of the costs for the LTD benefit plan as a result of the adoption of USGAAP is a reduction in the costs of $2.7M.

Board Staff Interrogatory #36

Ref: Ref: Exh A3-1-2 page 4 Chart 1

Issue Number: 6

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

Interrogatory

The total transition costs associated with the LTD benefits plan due to accounting changes to USGAAP in 2011 were calculated as $40.7M (i.e., $31.4M related to LTD and $9.3M related to higher restated costs in 2011) before tax impacts.

a) Please provide a detailed calculation showing the derivation of the $9.3M related to higher restated costs in 2011.

b) Please identify what amounts for LTD benefits were included in the current test period (March 2011 to December 2012) revenue requirement arising from the amortization of net cumulative unamortized actuarial gain or loss for the LTD plan (under the CGAAP corridor method) and past service costs related to the LTD plan. If there were any amounts included in the revenue requirement, should these amounts be an offset to the amounts recorded in the USGAAP Deferral Account or should the amounts be included in the true-up reflected in the Pension and OPEB Variance Account?

c) Please provide the journal entry in OPG's financial accounting records including the date of the entry for the $40.7M LTD benefits plan in relation to the changes in 2011 as recorded in OPG's financial records.

d) Please explain why the $40.7M LTD benefits plan attributable to accounting changes in the 2011 financial year (while still under CGAAP) should be classified as "transition costs" and be carried forward for inclusion as part of the 2012 account balance and should be recoverable given that the approved deferral account is effective from January 1, 2012 to the effective date of the next payment amounts order.

Response

The question incorrectly references changes as having occurred in 2011. As explained in part (d) below, the referenced changes occurred on January 1, 2012.

(a) As shown in Ex. H1-1-1, Table 6, lines 2-4, col. (c), the amount of $9.3M represents the difference between the regulated portion of OPG-wide USGAAP and CGAAP costs associated with the LTD benefit plan. As shown in note 3 to that Table, the OPG-wide costs were $45.1M under USGAAP and $33.2M under CGAAP. The difference of $11.8M (after rounding of individual amounts) is also shown in Ex. A3-1-2, Attachment 3, p. 5 under "Summary of Financial Results" in the bottom table. The details underlying this difference are provided below.

Net actuarial loss for 2011 immediately recognized under USGAAP *(from Ex. A3-1-2, Attachment 3, page 23)*	$13,207K
Amortization in 2011 of previously deferred net actuarial loss under CGAAP *(from Ex. H2-1-3, Attachment 2, Schedule 1)*	-$ 1,004K
Amortization in 2011 of previously deferred past service cost under CGAAP *(from Ex. H2-1-3, Attachment 2, Schedule 1)*	-$ 388K
Difference between amounts recognized in 2011 under USGAAP and CGAAP	**$11,818K**

The $9.3M for OPG's regulated operations is determined by assigning OPG-wide costs using the methodology approved in EB-2010-0008 as referenced in response to interrogatories L-1-1 Staff-14(c) and L-1-1 Staff-34 c).

(b) The amounts included in the approved EB-2010-0008 test period forecast of CGAAP pension and OPEB costs for amortization of the net cumulative unamortized loss and past service costs related to the LTD benefit plan are provided below, with full-year 2011 forecast amount pro-rated by 10/12:

$	**Mar-Dec 2011**		**Jan-Dec 2012**	
	Regulated Hydro	**Nuclear**	**Regulated Hydro**	**Nuclear**
Amortization of Net Cumulative Unamortized Loss	2K	38K	1K	15K
Amortization of Past Service Costs	12K	240K	14K	288K
Total	**14K**	**278K**	**15K**	**303K**

These amounts should not be an offset to amounts recorded in either the Impact for USGAAP Deferral Account or the Pension and OPEB Cost Variance Account.

As noted in Ex. H2-1-3, p. 1, line 29, the EB-2011-0090 Decision and Order specifically stated that the Pension and OPEB Cost Variance Account is to capture "the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the EB-2010-0008 Decision and the resulting payment amounts order, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts" effective March 1, 2011. The above amounts were included in OPG's approved payment amounts as part of OPEB costs effective March 1, 2011; therefore they should be and have been used by OPG to determine, for recording into the Pension and OPEB Cost Variance account, the difference between amounts collected in approved payment amounts and actual amounts as described above.

As cited at p. 3, lines 21-22 of Ex H2-1-3, the OEB also stated in the EB-2011-0090 Decision and Order that “there will be no entries in the variance account related to changes in accounting standards, such as IFRS or USGAAP,” i.e., the variances are to be computed on a CGAAP basis. As per EB-2011-0432, financial impacts associated with the adoption of USGAAP are recorded by OPG in the Impact for USGAAP Deferral Account.

Having “trued-up”’ the LTD benefit plan costs, including the above amortization, to actual costs on a CGAAP basis as a result of the Pension and OPEB Cost Variance Account, the Impact for USGAAP Deferral Account therefore appropriately captures the incremental variance between actual LTD benefit plan costs on a CGAAP basis and those on a USGAAP basis.

(c) The following provides the regulated portion of the journal entries recorded by OPG as part of the 2012 Restatement discussed at Ex. A3-1-2, p.3, lines 4-9. The entries were recorded in February 2012, with the opening balance sheet entry posted as of year-end 2010[1] and the 2011 cost adjustment entries posted as of each of the four quarter-end dates for 2011.

Opening Balance Sheet Adjustment Entry

DR	Retained Earnings	$31.4M	
CR	LTD Liability		$31.4M

Total of Adjustment Entries for 2011 Costs

DR	LTD Cost	$9.3M	
CR	LTD Liability		$9.3M

(d) OEB Staff characterize the $40.7M in transition costs as occurring “in the 2011 financial year.” They implicitly assume that these costs should not be allowed because they occur before the January 1, 2012 effective date of the Impact for USGAAP Deferral Account. For the reasons outlined below, this characterization is incorrect. As a result, the $40.7M in transition costs are eligible for recovery.

As explained in Ex. A3-1-2 starting at p. 4, line 18 to p. 5, lines 10, the amount of $40.7M would have been included in the calculation of recoverable costs under CGAAP in subsequent years and would have been part of the revenue requirement in future payment amounts applications. Since these costs would have been eligible for recovery under CGAAP, it is fair to provide for their recovery under USGAAP (i.e., neither customers, nor OPG, are financially disadvantaged from the change to USGAAP).

The timing of these costs is not an impediment to their being recorded in the Impact for USGAAP Deferral Account for three main reasons.

[1] For technical reasons, OPG’s general ledger system required the opening balance sheet entry to be posted as of year-end 2010, rather than January 1, 2011, in order for it to be reflected in the 2011 opening balance sheet

First, it is not appropriate to refer to the transition impact of $40.7M as “attributable to accounting changes in the 2011 financial year.” As stated at Ex. A3-1-2, p. 4, lines 3-5, the accounting change of OPG adopting USGAAP took place in 2012 effective January 1, 2012, and the transition costs, which are a direct consequence of the adoption, were therefore incurred on January 1, 2012, not in 2011. This view is supported by the fact that the journal entries for these transition costs (see part c) were recorded in February 2012.

Second, the question is based on an incorrect premise that costs calculated using amounts that have a relationship to a period prior to the effective date of the account cannot be recorded in the account. In actuality, the effective date of the account represents the point after which qualifying events give rise to entries into the account. Transition costs were required to be calculated using 2011 data because of the requirement to provide comparative USGAAP financial information as a consequence of OPG having adopted USGAAP. The “qualifying event” of OPG’s adoption of USGAAP took place in 2012. Put simply, both OPG’s adoption of USGAAP and the deferral account are effective January 1, 2012, and all costs resulting from the adoption start on that date.

Third, if these costs were incurred prior to 2012, they would have had to have been reflected in OPG’s 2011 historical financial information, as represented by OPG’s 2011 audited annual consolidated financial statements (Ex. A3-1-1, Attachment 1). No such costs were recorded or reported in those statements.

Board Staff Interrogatory #37

Ref: Exh A3-1-2 page 6

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

Interrogatory

OPG indicates that USGAAP requires the amount of base rent revenue to be recognized on a straight-line basis is 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).

a) Please confirm that the change in accounting under USGAAP starts retrospectively from the inception of the Bruce Lease on a straight-line basis for the Bruce Lease base rent and thus the impact of this change results in rents being recalculated from the lease inception and then applied prospectively starting in 2012 over the remaining years of the lease. If not, please provide a clarification.

b) Please explain whether CGAAP contains the same provisions for the use of the straight line basis since the inception of the Bruce Lease in 2001, and consequently whether this change in accounting could have been applied under CGAAP following the Board direction in EB-2007-0905.

c) Are there any changes to the approach used by OPG to determine the Bruce Lease supplemental rent revenues under USGAAP as compared to CGAAP?

Response

a) OPG can confirm that the impact of the cited USGAAP requirement results in base rent revenue being retrospectively recalculated from the inception of the Bruce Lease. The retrospectively recalculated revenue amount under USGAAP, net of deferred taxes, is lower by approximately $1.6M on an annual basis as compared to the amount that OPG has been recognizing since April 1, 2008 following the OEB's direction in EB-2007-0905 and would have continued to recognize under CGAAP. OPG will continue to recognize the lower amount under USGAAP going forward.

b) While CGAAP contains similar provisions to USGAAP requiring unregulated commercial entities to use straight-line accounting for certain lease revenues since the inception of the lease, OPG could not have accounted retrospectively to the inception of the Bruce Lease in adopting CGAAP effective April 1, 2008 following the direction in EB-2007-0905.

Prior to the OEB's direction in EB-2007-0905, in applying CGAAP provisions for accounting for rate-regulated operations then in effect, OPG accounted for base rent revenue on a cash basis, as this was the basis upon which this revenue was reflected in the information provided to the Province for the purposes of determining interim payment amounts for the period from April 1, 2005 to March 31, 2008. The OEB's direction in EB-2007-0905 resulted in a change in the way in which the revenues were to be reflected in the payment amounts, on a prospective basis, by requiring such amounts to be determined using CGAAP provisions for lease accounting applicable to unregulated commercial entities. In accordance with these CGAAP lease accounting provisions, OPG adopted the straight-line basis of accounting for base rent revenue effective April 1, 2008. Since the reason for this change was a prospective change in the regulatory treatment stemming from a new event (i.e., the OEB's direction), OPG was required to account for this change prospectively, as a change in estimate, in accordance with CICA Handbook Section 1506, *Accounting Changes*, paragraph 5(b), and therefore could not do so retrospectively.

c) No.

Board Staff Interrogatory #38

Ref: Exh A3-1-2, pages 2 and 9

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

Interrogatory

OPG has stated that, "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...the adoption of USGAAP for regulatory purposes would allow OPG to maintain a single accounting system once new USGAAP-based payment amounts are established."

a) Given that the CGAAP financial records for regulatory reporting purposes continue until OPG's payment amounts are reset in the future, why could OPG not make a request to use USGAAP for regulatory purposes at the time when the next payment amounts application is filed?

b) Are there any savings associated with the cost of recording-keeping in the near term if the Board approves the use of USGAAP for regulatory purposes in this application considering that OPG's payments amounts would not be reset under USGAAP until a cost of service application is subsequently filed?

Response

a) OPG has applied to use USGAAP for regulatory accounting, reporting and rate-making purposes. The primary driver for the request at this time is not regulatory reporting, as OPG must maintain CGAAP financial records for regulatory reporting purposes (although OPG only intends to audit CGAAP information to the extent it is required for the sole purpose of meeting OPG's regulatory obligations)[1] rate-making efficiency and cost avoidance are the primary drivers of the request to use USGAAP at this time as discussed below.

b) In the near term, approval of USGAAP for regulatory reporting purposes would allow OPG to avoid the costs described in Ex A3-1-2, p. 2. As explained in L-6-1 Staff-33, OPG does not maintain IFRS records; therefore approval of OPG's request would allow the company to avoid the costs necessary to develop IFRS financial records, analyze implementation options available on adoption of IFRS, and prepare financial statements. OPG's business planning is done on the same basis as its financial reporting (i.e., USGAAP). IFRS is not used. As OPG's business plan elements for regulated activities

[1] For example, pension and OPEB costs and Bruce lease revenues and costs will be audited to validate the variance account balances resulting from the difference between amounts reflected in EB-2010-0008 rates determined on a CGAAP basis and actual costs determined on the same CGAAP basis.

are used in preparing its payment amount applications, a change in accounting methodology for rate-making purposes would require the development and approval of an alternative business plan.

The financial reporting prepared on a USGAAP basis would underpin the historical year financial information contained in OPG's next application. If USGAAP is not accepted for regulatory reporting purposes, then trend analyses would require that historical year information be prepared (and perhaps audited) on an IFRS basis. This would create new costs to maintain and perhaps audit a second set of financial records and statements.

OPG notes that the OEB considered the use of USGAAP as a preliminary issue in both the recent Union Gas and Enbridge applications. The OEB's approach makes sense as these entire filings were based on USGAAP evidence. Union Gas and Enbridge would have been required to fully amend their applications to reflect the use of a different accounting basis, if the OEB had not approved the use of USGAAP for these companies. In OPG's view, it makes sense to get a decision on the method that the OEB will accept for regulatory accounting, reporting and ratemaking purposes, and then develop an application on that basis.

Board Staff Interrogatory #39

Ref: Exh A3-1-2

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

Interrogatory

OPG has identified only the LTD benefits as the key financial impact in the transition to USGAAP, the impact of which was recorded in the USGAAP Deferral Account. If OPG's request to use USGAAP for regulatory purposes is approved, should the USGAAP Deferral Account be closed to any new principal entries effective on January 1, 2013, except for the transitional LTD benefits until new payment amounts are set?

Response

At Ex A3-1-2, p. 5 OPG discusses Implementation Costs (line 12) and Tax Impacts (line 18) related to LTD costs, noting that both of these cost variances will continue until payment amounts are reset as part of the next payment amounts order. To be clear, these costs are both for nuclear and hydroelectric operations, so costs would continue to be recorded until new base payment amounts are established for both hydroelectric and nuclear operations on a USGAAP basis.

Board Staff Interrogatory #40

Ref: Exh A3-1-2

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

Interrogatory

OPG provided some benefits (and no disadvantages) for using USGAAP compared to the alternative of adopting IFRS for financial accounting and ratemaking purposes.

a) Please provide specific details for 2011 and 2012 including quantification of the financial accounting and ratemaking impacts in the revenue requirement arising from changes to capitalization under IFRS for, among other things, indirect administrative and general overhead costs and preconstruction project costs

b) Please provide the estimated 2011 and 2012 impacts arising from differences 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.

c) Please provide the estimated 2011 and 2012 impacts arising from any treatment change to LTD benefits for financial accounting and revenue requirement purposes under IFRS?

d) Please provide the estimated 2011 and 2012 impacts arising from any treatment change to accretion rates for financial accounting and revenue requirement purposes under IFRS?

Response

a) Excluding the impacts on nuclear liabilities discussed in parts (b) and (d) below, OPG accounting in the area of capitalization is consistent under IFRS, USGAAP and CGAAP.

   Specifically, OPG does not capitalize indirect administrative and general overhead costs. OPG only capitalizes direct costs related to a capital project. For the construction of new assets or refurbishment of an existing asset, capitalization commences once sufficient confidence is achieved through available evidence to support that the execution of the construction project will be completed and that the preferred alternative has been selected and approved.

b) In general, the full value of fixed nuclear liability costs expected to be incurred over the production lifecycle of nuclear facilities is considered to be committed and, therefore, is immediately recognized in the asset retirement obligation (“ARO”) and asset retirement costs (“ARC”). Variable costs are considered to be committed as incremental waste is generated, and therefore are recognized in the asset retirement obligation and expensed over time on a volumetric basis. There are two impacts related to the differences in the timing of recognition of certain costs due to their re-categorization from fixed costs under USGAAP/ CGAAP to variable costs under IFRS.

The first impact results from certain costs expected to be incurred for managing waste generated over the full production lifecycle of nuclear facilities being classified as fixed under CGAAP, whereas they would be classified as variable if OPG adopted IFRS. As a result, they would be removed from the previously recognized nuclear liability costs, reducing the asset retirement obligation on transition to IFRS. Instead, these removed costs would be recognized in subsequent periods, starting in 2011, as incremental waste is generated, resulting in higher variable expenses and therefore revenue requirement impacts under IFRS than under USGAAP/CGAAP.

Under the OEB-approved methodology described at Ex. C2-1-2 in EB-2010-0008, variable expenses are recovered through the revenue requirement when incurred as period expenses. The costs removed from the asset retirement obligation in establishing the opening IFRS balance sheet would continue to be included in ARC and recovered through depreciation of and the return on ARC in years following the transition in accordance with the OEB-approved methodology. This accounting timing difference between USGAAP/ CGAAP and IFRS would result in a higher recovery in future periods under IFRS. As a result, a deferral account would need to be established to address this higher revenue requirement impact over time, which, for matching purposes, may need to have a recovery period extending to the end-of-life dates for depreciation purposes of OPG's nuclear stations, the latest of which is currently December 31, 2051 for Darlington.

The second IFRS impact related to the re-categorization of costs would occur when the nuclear liabilities changed based on cost estimate changes in an updated ONFA Reference Plan such as occurred at the end of 2011.[1] Under IFRS, the changes in the nuclear liability costs included in the ARO as variable costs would be immediately expensed by OPG upon the reassessment of the ARO. All changes resulting from a reassessment of the ARO are capitalized by OPG under USGAAP/CGAAP; no impacts are expensed.

By being included in ARC under USGAAP/CGAAP, the impact of the ARO reassessment is included in the determination of future payment amounts through depreciation expense and, in the case of prescribed assets, return on ARC. The changes in these costs would include changes in cost estimates for managing nuclear waste and the impact of using a current discount rate to revalue the portion of the ARO related to variable costs using a

[1] Changes could also occur for other reasons such as changes in station lives for accounting purposes.

current accretion rate, as required under IFRS and discussed in part (d) below. This immediate expensing would both increase the revenue requirement and introduce additional volatility given that cost estimates are typically updated by OPG on a five-year cycle required under the ONFA. While OPG's base payment amounts determined on a USGAAP/CGAAP basis continue to be in effect, the expensed amounts resulting from ARO changes in 2011 onwards would need to be recorded in a deferral account to be recovered from ratepayers in order to achieve the same outcome as the capitalization of these costs under CGAAP (i.e., considered for recovery in the future).

c) The projected revenue requirement impacts for 2011 and 2012 related to LTD benefit plan costs, including transition costs, would have been the same under IFRS as under USGAAP, and are therefore discussed and presented in Ex. A3-1-2, Chart 1 and Ex. H1-1-1 Table 6, column c). The underlying pre-tax financial accounting impacts for 2011 are provided in the form of requested journal entries in L-6-1 Staff-36 part (c) with the following equivalent journal entry projected in 2012 (amount as shown in Ex. A3-1-2, Chart 1, line 4):

Total of Adjustment Entries for 2012 Costs

DR	LTD Cost	$3.2M	
CR	LTD Liability		$3.2M

d) As noted in L-2-1 Staff-20, IFRS would require OPG to revalue the full, rather than just the incremental, amount of its nuclear liabilities using an accretion rate determined at the time of their change. Under USGAAP/CGAAP, the existing liability continues to be carried at historical discount rates. Because of the requirement that entities adopt IFRS as if they had always reported under IFRS, if OPG had adopted IFRS on January 1, 2012 it would have been required to reflect the IFRS accretion rate methodology in the January 1, 2011 opening IFRS balance sheet. The IFRS rate would have been lower than the-then CGAAP weighted average rate of 5.58 per cent and therefore would have increased OPG's ARO on transition to IFRS. This increase in the ARO amount was not previously recovered from ratepayers through either the depreciation of or return on ARC, or variable expenses. Therefore, a deferral account would need to be established to allow for such recovery.

The impacts of the required IFRS accretion rate methodology would continue to increase the revenue requirement beyond the opening balance sheet calculation. Discount rates have been declining due to the current financial market conditions, as exemplified by the low accretion rate of 3.43 per cent applicable to the 2011 increase in the ARO under USGAAP/CGAAP as noted in Ex. H2-1-1, p. 4. When used as part of the IFRS accretion rate methodology, lower discount rates would result in significantly bigger increases in the ARO in 2011 and 2012, than under USGAAP/CGAAP. The impacts of the higher ARO would be recovered from ratepayers through higher subsequent depreciation of, and return on, ARC for prescribed assets (depreciation and accretion expense for Bruce assets) and higher variable costs. While payment amounts determined on a USGAAP/CGAAP basis continue to be in effect, the increases in the revenue requirement would also need to be recorded in a deferral account for future recovery.

Board Staff Interrogatory #41

Ref: Exh A3-1-2

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

Interrogatory

In moving to USGAAP, please explain how OPG could be benchmarked going forward and identify other utilities that would be comparable (e.g., cohort group) for benchmarking purposes.

Response

OPG will continue to engage in various financial benchmarking activities going forward using data from US utilities. OPG Nuclear derives its financial performance metrics (e.g., Total Generating Costs per MWh; Capital Cost per MW DER[1]) for its nuclear stations using Electric Utility Cost Group ("EUCG") databases (ref. EB-2010-0008, Ex. F2-1-1, p. 6, line 10). The utilities that make-up the EUCG database used by OPG Nuclear are, with the exception of Bruce Power and OPG, located in the United States, and include companies such as Constellation, Dominion Resources, Entergy, Exelon, FPL, First Energy, Progress Energy, Southern and TVA.

OPG's regulated hydroelectric stations also participate in EUCG. EUCG benchmarking also includes participation from Canadian and U.S. utilities, including: Manitoba Hydro, New Brunswick Power, Pacific Gas & Electric, U.S. Army Corps of Engineers, Tennessee Valley Authority and Bonneville Power Authority, among others.

In addition, regulated hydroelectric participates in OM&A unit energy cost ($/MWh) benchmarking carried out by Navigant Consulting (ref. EB-2010-0008, Ex. F1-1-1, p. 16, line 22). The Navigant Consulting benchmarking participants are predominantly from Canada (e.g., Algonquin Power, BC Hydro, TransAlta Utilities, Newfoundland and Labrador Hydro, TransCanada) and the United States (e.g., Tennessee Valley Authority, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, New York Power Authority). The hydroelectric stations benchmarked are diverse in size, type, location and age, and include a mix of run-of-the-river, peaking, and pumped storage stations.

The majority of the EUCG and Navigant Consulting benchmarking participants currently are or will be using USGAAP for financial reporting, including some Canadian participants (e.g., Algonquin Power, Newfoundland and Labrador Hydro, and TransCanada).

[1] DER stands for "Design Electrical Rating". For purposes of setting a target metric, capital cost is reported on a capital cost per MW DER.

Moving to USGAAP has the potential to improve accuracy of the benchmarking information. While each benchmarking organization (EUCG, Navigant) has its own requirements for reporting costs, no adjustments are typically made by the utility making the data submission or by the benchmarking organization related to differences in financial accounting standards. Therefore, greater consistency in financial accounting standards among participating utilities has the potential to improve accuracy by making benchmarking information more comparable.

Board Staff Interrogatory #42

Ref: Exh A3-1-2

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

Interrogatory

If IFRS does not permit regulatory accounting (e.g., recognition of regulatory assets and liabilities) effective for 2015, does OPG plan to seek further exemption relief from the Ontario Securities Commission in order to continue USGAAP for financial reporting purposes?

Response

OPG currently intends to seek exemption relief from the Ontario Securities Commission beyond 2014 in order to continue using USGAAP for financial reporting purposes as required by O. Reg. 395/11 under the *Financial Administration Act*, (Ontario.)

Board Staff Interrogatory #43

Ref: Exh A3-1-2

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

Interrogatory

In the revised 2012 *Accounting Procedures Handbook for Electricity Distributors,* Article 100 at page 3 and 4, it states, “For ratemaking under an alternative accounting framework [e.g., USGAAP and ASPE under Part II of the CICA Handbook], the Board may require or prescribe accounting procedures and requirements in such items as depreciation methodology, capitalization policy, employee benefit recovery, and specified deferral and variance accounts.”

Does OPG plan to proactively implement IFRS-based rules in its next cost of service application for the Board’s review, and if not, please provide an explanation?

Response

OPG does not plan to implement IFRS rules in its next cost of service application. OPG has applied for approval to adopt USGAAP for regulatory purposes in this application. OPG must adhere to USGAAP rules and maintain USGAAP financial records, as required by O. Reg. 395/11 under the *Financial Administration Act* (Ontario). Developing and maintaining IFRS records in addition to USGAAP would be costly and impractical.

Additionally, consistent with the required basis for financial reporting, OPG’s business planning process is and will continue to be based on USGAAP.

AMPCO Interrogatory #18

Ref: EB-2008-0408 Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, June 13, 2011, Page 33

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

Interrogatory

Preamble: The Board's Report states:

> "Issue 4:
> The Board requires a utility that adopts USGAAP or an alternate accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to:
> - 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 the standard from the appropriate Canadian securities regulator (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." [emphasis added]

a) Please summarize the disadvantages to OPG and its ratepayers of using USGAAP.

Response

a) As noted at Ex. A3-1-2, page 7, footnote 2, OPG is not aware of any disadvantages associated with adopting USGAAP for regulatory purposes relative to adopting IFRS.

Energy Probe Interrogatory #04

Ref: Exhibit A3, Tab 1, Schedule 2, p.2 of 12

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

Interrogatory

The Application notes that OPG is not seeking to recover the costs associated with the implementation of USGAAP for financial accounting purposes.

a) Please clarify that OPG is not seeking to recover the costs associated with the implementation of USGAAP for financial accounting purposes *in this Application*.

b) How does OPG propose to recover costs associated with the implementation of USGAAP in connection with financial accounting for its regulated businesses?

Some of OPG's payments in lieu of taxes are calculated according to the Income Tax (Canada) where the treatment of certain expenses (e.g. capital cost allowance) may differ from the corresponding treatment under CGAAP (e.g. depreciation).

c) Having adopted USGAAP, will it be necessary for OPG to revert to CGAAP and deviations therefrom as required under the Income Tax (Canada) in order to determine the required payment in lieu of taxes?

Response

a) and b) OPG is not seeking to recover the costs it has incurred in connection with implementing USGAAP for financial accounting purposes for its regulated businesses in this Application and will not seek recovery of these past costs in a future application.

b) No. OPG's payments in lieu of income taxes 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. Both the Supreme Court of Canada and the Canada Revenue Agency have confirmed that in ascertaining profit, a taxpayer can adopt any method that is consistent with the provisions of the *Income Tax Act* (Canada) and is based on well-accepted business principles. USGAAP meets these requirements and is acceptable for the purposes of computing OPG's taxable income and filing its tax returns.

Board Staff Interrogatory #44

Ref: Exh A3-1-2

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

a) Other than the three issues identified on adoption of USGAAP for regulatory accounting purposes that produced financial impacts (LTD, SR&ED tax credits, Bruce Lease Base Rent), please indicate whether other potential issues were identified by OPG, its auditors or its consultants, which may cause financial impacts while reporting under USGAAP in the 2013 to 2014 period. If so, please identify these and their potential financial impacts.

b) OPG had completed IFRS transition accounting work prior to its adoption of USGAAP for financial reporting purposes. If OPG is required to adopt IFRS for financial accounting and/or regulatory purposes in the future, please identify the key areas of accounting changes and their associated financial impacts in moving from USGAAP to IFRS.

Response

The assertion that OPG's transition to IFRS was completed is incorrect. The project was not completed and was discontinued in late 2011, as discussed in Ex L-6-1 Staff-33.

a) OPG has not identified any additional financial impacts beyond those identified in Ex. A3-1-2, nor is OPG aware of any other potential regulatory accounting impacts for 2013 and 2014.

   There are additional financial accounting differences that impact OPG's financial reporting, not OPG's regulatory accounting. For instance, there are financial accounting balance sheet classification differences that impact regulated operations such as the USGAAP requirement to recognize all actuarial gains and losses and past service costs for non-long term disability benefit plans through a charge to accumulated other comprehensive income, as offset by a regulatory asset (recognized for financial accounting purposes only), and an increase in the reported pension and OPEB liabilities, as discussed in Ex. A3-1-2, section 5.0 and Ex. A3-1-1, p. 3, lines 15-21.

b) Given the significant similarities between CGAAP and USGAAP as they apply to OPG at this time and given the continued uncertainty with respect to accounting for regulatory assets and liabilities under IFRS, OPG currently expects the key areas of financial accounting changes between USGAAP and IFRS, as they apply to OPG, to be: pension and OPEB, nuclear liabilities, recognition of regulatory assets and liabilities, and associated deferred tax impacts.

Beyond identifying the key areas above, OPG does not have specific accounting impacts of a hypothetical future movement from USGAAP to IFRS for reasons described in Ex L-6-1 Staff-33. As discussed in that interrogatory response, OPG would have to restart the IFRS conversion project in order to identify such impacts, which would be problematic for the reasons given in that interrogatory response. OPG does keep apprised of significant IFRS developments, such as new IFRS guidance, but does not do so in sufficient detail to enable the company to evaluate specific current or possible future transactions under IFRS.

Board Staff Interrogatory #45

Ref: Exh H2-1-3 Attachment 4, pages 5 and 6

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

Schedules 1 and 2 show the results for the 2012 post-employment benefits plan for CGAPP and USGAAP respectively. Schedule 1 shows LTD benefits plan cost of $29.3M under CGAAP whereas Schedule 2 shows $33.3M under USGAAP. Please explain why LTD under USGAAP has increased by $4M compared to CGAAP, including the accounting changes that caused this difference in the estimation.

Response

The difference in the cited OPG-wide LTD benefit plan costs is due to the difference in the accounting treatment of actuarial gains and losses and past service costs related to the LTD benefit plan under USGAAP and CGAAP. As explained in Ex. A3-1-2, section 4.1, such gains or losses and past service costs are deferred and amortized under CGAAP whereas they are recognized immediately under USGAAP. As also explained in that section, this difference in accounting treatment is what gives rise to entries into the Impact for USGAAP Deferral Account related to the regulated portion of the OPG-wide amounts, as explained for 2012 in Note 4 to Ex. H1-1-1, Table 6.

Specifically, Ex. H2-1-3, Attachment 4, Schedule 1 shows $388K for amortization of previously deferred past service cost and $1,937K for amortization of previously deferred net actuarial loss as components of the projected 2012 OPG-wide CGAAP LTD benefit plan cost of $29,306K. Schedule 2 of the same attachment shows nil for amortization of past service cost but a higher amount of $6,299K for amortization of net actuarial loss as components of the projected 2012 OPG-wide USGAAP LTD benefit plan cost of $33,280K. Although labeled as "amortization" for presentation consistency with Schedule 1, the amount of $6,299K in Schedule 2 represents the immediate recognition of the projected net actuarial loss for 2012 under USGAAP. This amount is deferred under CGAAP and instead, the projected cost includes a lower amount of amortization of $1,937K of previously deferred net actuarial loss (and $388K for past service cost), resulting in a lower overall cost under CGAAP.

AMPCO Interrogatory #19

Ref: Ref #1: Exhibit A3-1-2, Page 5 Lines 12-16
Ref #2: Exhibit H1-1-1 Table 6

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

Preamble: Reference #1 states the difference in accounting treatment of LTD costs required as a result of the adoption of USGAAP is projected to produce higher costs during 2012. Variances are recorded in the Impact for USGAAP Deferral Account. The Table in Reference #2 (line7) shows a $3.2 M projected variance for 2012.

a) Please provide the derivation and calculation of the $3.2 M including all inputs and assumptions.

b) The notes to the Table reference the regulated portion of total OPG LTD benefits costs. Please confirm OPG's allocation methodology of costs between regulated and non-regulated.

Response

a) As shown in Ex. H1-1-1, Table 6, lines 5-7, col. (c), the amount of $3.2M represents the projected difference between the regulated portion of OPG-wide USGAAP and CGAAP costs associated with the LTD benefit plan calculated for 2012. As shown in note 4 to that Table, the projected OPG-wide costs calculated for 2012 are $33.3M under USGAAP and $29.3M under CGAAP. The difference of $4M and its derivation, based on the report from OPG's independent actuary Aon Hewitt, provided at Ex. H2-1-3, Attachment 4, pp. 5-6, are discussed in response to Interrogatory L-7-1 Staff-45. The underlying actuarial methods and assumptions are outlined starting at page 3 of Ex. H2-1-3, Attachment 4.

b) The $3.2M regulated portion of the above OPG-wide difference was determined using the methodology for assigning centrally-held pension and OPEB costs described in the EB-2010-0008 pre-filed evidence at Ex. F4-3-1, section 6.3.3 and reflected in approved EB-2010-0008 payment amounts. This methodology has been applied consistently as referenced in responses to Interrogatories L-1-1 Staff-14(c), L-6-1 Staff-34(c), and L-6-1 Staff-36(a).

SEC Interrogatory #33

Ref: A3/1/2, p. 4

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

Please confirm that the $31.4 million of LTD costs referred to in Chart 1 represents unamortized net actuarial losses and pas service costs from the period prior to 2011, which as a result of the conversion to USGAAP are required to be charged to AOCI as of January 1, 2012. Please confirm that the amount of $9.3 million is a similar adjustment for amounts arising in 2011 and required to be charged to AOCI as of January 1, 2012. Please confirm that the amount of $3.2 million is a similar adjustment for amounts expected to arise in 2012 and required to be charged to AOCI as of January 1, 2013.

Response

Not confirmed. The interrogatory incorrectly indicates that amounts are charged to Accumulated Other Comprehensive Income ("AOCI"). In fact, these amounts affect retained earnings. The $31.4M amount and its impact are explained in Ex. A3-1-2, pp. 4-5 with further details provided in L-6-1 Staff-35 and 36. The $9.3M amount and its impact also are discussed in L-6-1 Staff-35 and 36. The amount of $3.2M is similar in nature to the $9.3M amount and is discussed in L-7-1 Staff-45 and L-7-2 AMPCO-19.

SEC Interrogatory #34

Ref: A3/1/2, p.5

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

Please confirm that the timing of the tax cost of $14.6 million is driven by the period over which the proposed amounts in the deferral account are collected. Please confirm that, subject to changes in income tax rates, the relationship between the period of recovery and the incidence of the additional tax is linear, i.e. if recovered over 2 years, the tax cost is $7.3 million per year, and if recovered over 10 years, the cost is $1.46 million per year.

Response

The projected $14.6M income tax impact amount recorded in the Impact for USGAAP Deferral Account (Ex. H1-1-1, Table 6, line 8) is caused by the projected additions for the long-term disability benefit plan cost differences of $43.9M for the period ended December 31, 2012 (Ex. H1-1-1, Table 6, lines 1+4+7). Therefore, the $14.6M is independent of the period of recovery of the account balance. The recovery of this income tax impact amount as part of the disposition of the account balance is necessary to offset the additional income taxes payable by OPG upon the recovery of the balance.

If the account is recovered on a linear basis and tax rates remain constant, the recovery will result in a linear impact on income taxes payable during the recovery period.

SEC Interrogatory #35

Ref: A3/1/2, p.6, and L/6/1, Staff 37

Issue Number: 7
Issue: Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Interrogatory

Please confirm that the impact described in 4.2.2 is not being recorded in the Impact of USGAAP Deferral Account, but will have an impact on the Bruce Lease Net Revenues Variance Account. Please provide a table showing a) the actual/forecast total annual base rent, b) the amount recognized under CGAAP, and c) the amount that would have been recognized under USGAAP, for each year from the beginning of the Bruce Lease to 2015.

Response

The impact described in Ex. A3-1-2, section 4.2.2 is not being recorded in the Impact of USGAAP Deferral Account.

The Bruce Lease Net Revenues Variance Account records differences between revenues and costs determined on a CGAAP basis reflected in the current payment amounts, and actual CGAAP revenues and costs. This approach applies for all approved variance and deferral accounts as discussed in Ex. A3-1-1, p. 2, lines 16-18. As noted in Ex. A3-1-2 section 4.2.2, the reduction in base rent revenue under USGAAP will increase revenue requirement in OPG's next application for new nuclear payment amounts based on USGAAP, but, until such time, has no impact on the deferral or variance account balances, as noted above.

As discussed in response to L-6-1 Staff-37, the annual amount of retrospectively calculated base rent revenue, net of deferred taxes, under USGAAP, is approximately $1.6M lower as compared to the amount that OPG has been recognizing under CGAAP following the OEB's direction in EB-2007-0905. As noted in Ex. A3-1-2, section 4.2.2, the $1.6M amount represents a difference in pre-tax base rent revenue of $2.2M per year, net of a reduction in deferred taxes of $0.6M per year.

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 this information in attached Table 1 for the period during which OPG has been regulated by the OEB. OPG understands the description of item a) requested in the question to mean the amount of base rent payable to OPG under the Bruce Lease agreement (i.e., cash basis). As such, Table 1 shows, for each year 2008 to 2013 on a pre-tax basis, base rent payable under the Bruce Lease, base rent revenue recognized under CGAAP, and retrospectively recalculated base rent revenue under USGAAP.

Base rent revenue amounts for periods after 2013 are not relevant to the clearance of the 2012 audited actual account balances.

Numbers may not add due to rounding.

Table 1
Bruce Lease Base Rent - 2008 to 2013 ($M)

No.	Particulars	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Projected	2013 Projected
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Base Rent Payable under the Bruce Lease Agreement**	72.0	74.0	76.0	78.0	80.0	81.0
2	**Base Rent Revenue under CGAAP**[1]	72.7	40.9	40.9	40.9	40.9	40.9
3	**Base Rent Revenue under USGAAP**[2,3]	69.5	38.7	38.7	38.7	38.7	38.7

Notes:

1. Amounts for 2008 and 2009 from EB-2010-0008 Ex. G2-2-1, Table 2, line 5, cols. (b) and (c), respectively.
   Amount for 2010 is that underpinning the December 31, 2010 audited balance of the Bruce Lease Net Revenues Variance Account approved for recovery in the EB-2010-0008 Payment Amounts Order. Amounts for 2011 and 2012 are from EB-2012-0002 Ex H1-1-1 Table 14a, line 5, cols. (c) and (f), respectively.
   Amounts for 2011 and 2012 are from EB-2012-0002 Ex H1-1-1 Table 14a, line 5, cols. (c) and (f), respectively.
   Amount for 2013 is as also shown in Table 1 to L-1-7 SEC-4.
2. Amounts for 2008 to 2010 as retrospectively recalculated under USGAAP. Amount for 2011 as restated by OPG for purposes of comparative financial information required to be presented upon adoption of USGAAP on January 1, 2012.
   Projected amounts for 2012 and 2013 as recognized in OPG's consolidated USGAAP financial statements.
3. Difference between 2008 CGAAP and USGAAP amounts includes that arising for the first quarter of 2008 due to the use of the cash basis of accounting, prior to the effective date of the OEB's direction in EB-2007-0095 that resulted in a change to straight-line accounting effective April 1, 2008.