ONTARIOPOWER GENERATION

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December 7, 2012

VIA RESS AND COURIER

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

Dear Ms. Walli:

EB-2012-0002 – Responses to Board Staff Interrogatories

Attached please find OPG's responses to interrogatories from OEB Staff.

Certain of the interrogatories would benefit from updated financial information, particularly those dealing with pension and OPEB costs based on the actual discount rates to be established at the end of 2012. Prior to the oral hearing, OPG plans to file an update to its evidence to reflect material changes and will update the relevant interrogatory responses at that time. This will be done in February 2013.

Two paper copies are provided with this letter, as per Procedural Order #1. OPG is also submitting this document on the Regulatory Electronic Submission System ("RESS"). Intervenors have been sent electronic copies via email.

Best Regards,

[Original signed by]

Garry M. Hendel

Attach

cc:	Charles Keizer (Tory's)	via email (no attachments)
	Carlton Mathias	via email (no attachments)
	EB-2012-0002 Intervenors	via email

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	99
2	Return on Rate Base	6
3	Variable Expenses – Used Fuel Management	25
4	Variable Expenses – Low & Intermediate Level Waste Management	1
5	Income Tax Impact	24
6	**Addition to Deferral Account**	**155**

The above estimate reflects the forecast asset retirement cost adjustment at the end of 2012, as provided in the bottom portion of Ex. H2-1-1, Table 3, and other assumptions used in the pre-filed evidence. The actual amount of the asset retirement cost adjustment and related inputs into the calculation of 2013 additions to the deferral account will not be known until December 31, 2012. As discussed in OPG's December 7, 2012 interrogatory response transmittal letter to the Ontario Energy Board, OPG plans to file an update to this interrogatory to reflect the actual results for 2012 in February 2013.

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* **Error! Hyperlink reference not valid.** *[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.

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

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 2010-0008, 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.

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.

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

Line No.	Account	January - February 2011 Transactions[1]	Interest[1]	Total	March - December 2011 Transactions[2]	Interest[2]	Total	Projected January - December 2012 Transactions[3]	Interest[3]	Total	Grand 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

Numbers may not add due to rounding.
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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

TABLE OF CONTENTS

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**			

<u>**Note 1**</u>
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.

<u>**Note 2**</u>
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

MEMORANDUM

2011 Depreciation Review Recommendations – Regulated Business

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.

MEMORANDUM

2011 Depreciation Review Recommendations – Regulated Business

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.

MEMORANDUM

2011 Depreciation Review Recommendations – Regulated Business

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.

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			Projected 2012		
		Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	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			Projected 2012		
		Hydroelectric	**Nuclear**	**Total**	**Hydroelectric**	**Nuclear**	**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			2012		
		Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Forecast Additions to / Deductions from Regulatory Earnings Before Tax						
1a	Full Year Pension Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	5.8	114.0	119.8	8.1	162.8	170.9
2a	Full Year OPEB Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	8.0	159.3	167.3	8.3	166.7	175.0
3a	Less: Full Year Pension Plan Contributions from EB-2010-0008, Ex. L-01-085	9.9	196.2	206.1	9.9	196.2	206.1
4a	Less: Full Year OPEB Payments from EB-2010-0008, Ex. L-01-085	3.6	71.9	75.5	3.9	76.9	80.8
5a	Net Additions to Regulatory Earnings Before Tax	0.3	5.2	5.5	2.6	56.4	59.0
6a	Forecast Regulatory Income Tax Impact (line 5a x tax rate / (1 - tax rate)) (note 4)	0.1	1.9	2.0	0.9	18.8	19.7
7a	Hydroelectric Mar-Dec 2011 Amount ((line 6a, 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.

Numbers may not add due to rounding.

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.

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.

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

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
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	161.7	426.3	588.0
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		161.7	426.3	588.0
8	**Total Approved 2011-12 Production (TWh)**	5	39.7	101.9	141.6
9	**Required Recovery ($/MWh)** (line 7 / line 8)		4.07	4.18	4.15
10	**Typical Monthly Consumer Bill Impact ($)** (line 4 x line 9)		0.47	1.23	1.70
11	**Typical Monthly Residential Consumer Bill ($)**	6	116.30	116.30	116.30
12	**Percentage Increase in Consumer Bills** (line 10 / line 11)		0.40%	1.06%	1.46%

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 Update IESO 18-Month Outlook issued June 22, 2012, Table 3.1, which can be found 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 ($M) (H1-1-1 Table 1, col. (f), line 11 (Reg. Hydro), H1-1-1 Table 2, col. (f), line 11 (Nuclear))	96.2	867.5
2a	EB 2010-0008 Payment Riders ($/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)	161.7	426.3

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.

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.

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-2011-0090 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.

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.