EB-2009-0038

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities;

OPG COMPENDIUM OF EVIDENCE

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OPG Compendium of Evidence

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TAB 1

EB-2007-0905
EB-2008-0380

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities;

AND IN THE MATTER OF Rule 42 of the Rules of Practice and Procedure of the Ontario Energy Board.

NOTICE OF MOTION

Ontario Power Generation Inc. ("OPG") will make a motion to the Ontario Energy Board ("OEB") at its offices at 2300 Yonge Street, Toronto on a date and time to be fixed by the Board.

The Motion is for:

1. a review and variance of the OEB's decision of November 3, 2008 in EB-2007-0905 (the "Decision"), as confirmed by the decision of the OEB review panel dated December 19, 2008 in EB-2008-0380 (the "Review Panel Decision") (attached as Appendix 1) which dismissed OPG's November 24, 2008 motion for review and variance of the Decision (the "Motion to Vary," attached as Appendix 2) on preliminary grounds;

2. an Order:

   (a) for an oral hearing of the Motion on the merits and, ultimately, for an order:

      (i) varying the approximately $342 million reduction in OPG's revenue requirement in the absence of any legal basis for the reduction;

      (ii) varying the finding that there was no connection between OPG's proposed revenue requirement reduction and regulatory tax losses carried forward from the 2005-2007 period in the absence of any evidence to support this finding; and

(b) as an efficient method to give effect to (a) (i) and (ii) above, given the OEB's Payment Amounts Order dated December 2, 2008, establishing a variance account to record the revenue requirement reduction of $342 million incorporated in the test period payment amounts and directing that the disposition of that account be conducted in conjunction with consideration of the analysis of prior period tax returns in OPG's next case;

or, in the alternative,

(c) for an oral hearing on the threshold question of whether OPG's Motion to Vary raises a substantial question as to the correctness of the Decision; and

3. such further and other relief as counsel may advise and the Board permit.

The Grounds for the Motion are:

1. There exist substantial questions as to the correctness of the Decision, including:

(a) the OEB exceeded its jurisdiction by ordering a revenue requirement reduction of $342 million without evidentiary or legal foundation. In this regard, the Decision unlawfully deprives OPG of the opportunity to recover its OEB-approved costs and its OEB-approved return on equity;

(b) the OEB erred in fact and in law in finding that there was "no connection" between regulatory tax losses and OPG's proposal to reduce its test period revenue requirement; and

(c) the OEB's analysis and disposition of the regulatory tax loss and mitigation issue was never advanced at the hearing by OEB Staff, intervenors, OPG or the OEB itself. As a result, OPG was deprived of the opportunity to respond to the OEB's approach to the regulatory tax loss and mitigation issue, disclosed for the first time upon release of the Decision.

The Review Panel Decision did not address any of these issues.

2. the Review Panel Decision was made without a hearing;

3. while the OEB's Rules of Practice and Procedure contemplate the possibility of a decision being made not to review a motion to vary on preliminary grounds without a hearing, it has not been the OEB's practice to do so (see: EB-2006-0322 et al., Decision with Reasons, May 22, 2007 and Hydro One Connection Procedures Decision, EB-2007-0797, Decision and Order, November 26, 2007). OPG had a reasonable expectation that it would be heard on the threshold issue and basic fairness requires that it should have been heard before any decision to dismiss the Motion to Vary was made;

4. the OEB's powers, under Rule 43, to review all or part of any order at any time and to vary, suspend or cancel that order;

5. the OEB's Rules of Practice and Procedure, in particular:

   (a) Rule 1.03 which provides that the OEB may dispense with, amend, vary or supplement, with or without a hearing, all or part of any rule at any time, if it is established that the circumstances of the proceedings will require, or it is in the public interest to do so;

   (b) Rule 2.01 which provides that the Rules shall be liberally construed in the public interest to secure the most just, expeditious, and efficient determination on the merits of every proceeding before the OEB;

   (c) Rule 2.02 which provides that where procedures are not provided for in the Rules, the Board may do whatever is necessary and permitted by law to enable it to effectively and completely adjudicate on the matter before it; and

   (d) Rules 5, 7, 8 and 42 to 45 of the Rules; and

6. such further and other grounds as counsel may advise and the OEB permit.

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Documentary Support

The documentary support upon which OPG intends to rely will consist of material from the record in this proceeding, the Decision and OPG's Submission provided with this Motion.

January 28, 2009

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AND TO: All Intervenors

Ontario Energy Board | **Commission de l'Énergie de l'Ontario**

Ontario

EB-2008-0380

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to Rule 42 of the *Rules of Practice and Procedure* for an Order varying part of the Ontario Energy Board's Decision with Reasons made November 3, 2008.

BEFORE: Paul Vlahos
Presiding Member

Cynthia Chaplin
Member

Ken Quesnelle
Member

DECISION AND ORDER

On November 24, 2008 Ontario Power Generation Inc. ("OPG") filed a Notice of Motion (the "Motion") for a review and variance of the Ontario Energy Board's (the "Board")

Decision with Reasons in file number EB-2007-0905, dated November 3, 2008 6
("Decision"). The Motion has been assigned file number EB-2008-0380.

The Decision dealt with payment amounts for OPG's prescribed facilities. One of the matters dealt with by the Board was OPG's proposal regarding treatment of tax losses and mitigation. In its Motion, OPG described the requested relief as follows:

> OPG seeks to vary the portion of the Decision dealing with the treatment of tax losses to provide for:
>
> (i) a clear acknowledgement of the link between OPG's mitigation proposal and the tax losses...
>
> (ii) a clear acknowledgement that OPG's mitigation proposal is not an unqualified gift but rather, was unambiguously based on OPG's calculation of prior period regulatory tax losses notionally available to be carried forward into the test period, based on the "stand-alone" principle and the principle that "benefits follow costs."...
>
> (iii) a clear acknowledgement that OPG will, under no circumstances, be found liable to provide credits to customers on account of any regulatory tax losses which have the effect of requiring OPG to credit customers twice for the same tax losses; and
>
> (iv) the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the draft rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Decision as to the re-calculation of those tax losses...[1]

The Motion is brought under Rule 44 of the Board's *Rules of Practice and Procedure* which states:

> Every notice of a motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

[1] Ontario Power Generation Inc. Notice of Motion, November 24, 2008, p, 4.

(i) error in fact;
(ii) change in circumstances;
(iii) new facts that have arisen;
(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to Rule 42, request a stay of the implementation of the order or decision or any part pending the determination of the motion.

Rule 45 of the *Rules of Practice and Procedure* states the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

The review panel has determined that there are no grounds for review. In the review panel's view, the objective of the relief sought is to protect OPG from findings that *might* be made as a result of a future panel's interpretation of the Decision in the next OPG Payment Amounts application. The Motion anticipates an interpretation which is detrimental to OPG, and seeks to safeguard against such an interpretation by obtaining acknowledgements from the review panel which effectively remove the possibility of such an interpretation being made. It is the review panel's opinion that what is being sought is not the proper subject of a review motion as it is based upon how the Decision might be interpreted rather than the Decision proper.

The right of a future panel to interpret and apply the Decision as it sees fit cannot be pre-empted. OPG will have the opportunity to present its interpretation of the Decision as it relates to tax losses and mitigation to the future panel; OPG will also be able to present its concerns with respect to other potential interpretations. The future panel will undoubtedly inform itself as to all the relevant circumstances in determining the appropriate balance between customers and OPG. If after the next Payment Amounts proceeding and Board decision OPG is of the view that the interpretation and application of the Decision has led to customers receiving credit twice for the same amounts, OPG may bring a motion to vary at that time.

THE BOARD THERFORE ORDERS THAT:

The Motion is dismissed.

ISSUED at Toronto, December 19, 2008
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

NOTICE OF MOTION

1. Ontario Power Generation Inc. ("OPG") will make a motion to the Ontario Energy Board ("OEB") on a date and time to be fixed by the OEB.

2. The motion is for a review and variance of part of the OEB's Decision with Reasons dated November 3, 2008 ("Decision") as set out below.

The Issue

3. Chapter 9 of the Decision is entitled "Design and Determination of Payment Amounts."

4. In earlier chapters of the Decision the OEB ruled on the recovery of all of OPG's costs for April 1, 2008 to December 31, 2009 (the "test period"). The OEB essentially ordered that OPG's test period costs were recoverable for one of three reasons: 1) because recovery was required by O.Reg. 53/05; 2) because they were found to be a reasonable forecast of test period costs associated with the prescribed facilities; and, 3) in the case of cost of capital, because recovery was required by the fair return standard. In coming to these conclusions, the OEB accepted and adopted the "stand-alone" principle, whereby the revenues and costs of OPG's regulated business (i.e., the facilities prescribed by O. Reg. 53/05) were determined independently of OPG's other, unregulated businesses.

5. In Chapter 9, the OEB dealt with OPG's mitigation proposal, which was based on tax losses which arose from 2005 to 2007 (the "prior period"). OPG fully utilized those tax losses on an actual basis to offset overall corporate income by the end of December 31,

2007. However, notwithstanding that the tax losses were fully utilized in the prior period on a corporate basis, OPG proposed (applying the "stand-alone" principle and the principle that "benefits follow costs") to carry the tax losses forward as "regulatory tax losses" and to apply them to reduce OPG's revenue requirement in the test period. OPG did so because: 1) the tax losses arose from contributions OPG was required to make to fund nuclear waste and decommissioning obligations associated with operations at the Pickering, Darlington and Bruce nuclear generating stations and other costs related to the nuclear facilities incurred in the prior period; and, 2) the consumer impact of the expenditures that led to the prior period tax losses either were or are likely to be recovered from consumers in OPG's payment amounts.

6. The OEB, however, contrary to the evidence and its own findings of fact, held that there was no connection between OPG's mitigation proposal and OPG's prior period tax losses.

7. Further, even though the OEB was not convinced that there were any prior period regulatory tax losses to be carried forward after December 31, 2007, the OEB nevertheless purported to require OPG to maintain an amended form of its mitigation proposal (i.e., required OPG to make an unqualified "gift" to consumers which represents the revenue requirement impact of the amount required to reduce taxes otherwise payable in the test period to zero plus an additional 22% of the revenue deficiency as determined by the OEB in the Decision).

8. The OEB also directed OPG to file in its next application an analysis of its prior period tax returns which would identify all items that "should be taken into account in the tax provision for the prescribed facilities."

9. In other words, the OEB appears to have found that there was no link between OPG's mitigation proposal and the tax losses on the basis that it was not convinced that there *were* any regulatory tax losses to carry forward after December 31, 2007, ordered OPG to reduce its revenue requirement by an amended amount based on its mitigation proposal anyway, and held that, for 2010 and beyond, OPG will be required to provide an analysis of prior period tax returns which appears intended to result in the OEB ordering

additional credits to consumers based on the very prior period tax losses that formed the basis of OPG's mitigation proposal in the first place. 11

10. In this context, specifically, OPG is seeking a review and variance of pages 167 to 172 of chapter 9 of the Decision, which purport to delink OPG's mitigation proposal from the prior period tax losses, require OPG to make an unqualified gift to consumers and expose OPG to liability to credit consumers twice for the same prior period tax losses.

The Grounds

11. The grounds for this motion which raise a question as to the correctness of the Decision are as follows.

(a) The OEB's analysis and disposition of the tax loss issue was never advanced before or during the hearing by Board Staff, intervenors, OPG or the OEB itself. As a result, OPG was deprived of the opportunity to respond to the OEB's approach to the tax loss issue, disclosed for the first time upon release of the Decision.

(b) The OEB erred in fact and in law by failing to recognize regulatory tax loss carry forwards as the basis for OPG's proposal to mitigate payment amounts in the test period.

(c) The OEB exceeded its jurisdiction by arbitrarily ordering OPG to make an unqualified gift to consumers. In this regard, the OEB's Decision on the tax loss issue is confiscatory and unlawfully deprives OPG of the opportunity to recover its OEB-approved costs and its OEB-approved return on equity. In the absence of the relief sought in this motion, it will be OPG's position that there is no mitigation available (tax loss or otherwise) to reduce test period payment amounts.

(d) The OEB's Decision on the tax loss issue is unreasonable in that it appears intended to result in double counting tax loss credits to consumers – once as a result of OPG's use of regulatory tax losses to calculate mitigation of the test period revenue requirement and again in connection with the re-assessment of OPG's prior period tax returns when setting payment amounts in 2010 and beyond.

The Relief Sought

12. OPG seeks to vary the portion of the Decision dealing with the treatment of tax losses to provide for:

(i) a clear acknowledgement of the link between OPG's mitigation proposal and the tax losses. There was clear evidentiary support for this link and no contrary evidence;

(ii) a clear acknowledgement that OPG's mitigation proposal is not an unqualified gift but rather, was unambiguously based on OPG's calculation of prior period regulatory tax losses notionally available to be carried forward into the test period, based on the "stand-alone" principle and the principle that "benefits follow costs." This too was supported by the evidence and there was no contrary evidence;

(iii) a clear acknowledgement that OPG will, under no circumstances, be found liable to provide credits to customers on account of any regulatory tax losses which have the effect of requiring OPG to credit customers twice for the same tax losses; and

(iv) the establishment of a tax loss variance account. This variance account would record any variance between the tax loss mitigation amount which underpins the draft rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in the Decision as to the re-calculation of those tax losses. Disposition of the balance in this account would be addressed as part of OPG's next payment amounts application.

Documentary Support

14. The documentary support upon which OPG intends to rely will consist of material from the record in this proceeding and the Decision together with such other material as may be required. It is OPG's intention to prepare a compendium of the relevant documentary material and to file that compendium, along with a written summary of argument, in due course in advance of the hearing of this motion.

November 24, 2008

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AND TO: All Intervenors

TAB 2

Exhibit F3 - Other Operating cost items

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Gannett Fleming also recommended increased use of benchmarking of certain asset service lives as an additional means of ensuring the impartiality of the DRC process. In 2008, OPG will consider benchmarking the service lives of its hydroelectric assets and certain components of its nuclear facilities for which meaningful comparison data can be obtained.

The second recommendation relates to transparency and understandability of the DRC report in a regulatory forum. The 2006 DRC report that Gannett Fleming reviewed focused on documenting the results of the DRC and provided limited information on asset selection criteria or depreciation policies and procedures. In order to address Gannett Fleming's recommendation in this area, OPG intends to document the asset selection criteria in its subsequent DRC reports in greater detail and has also documented relevant depreciation policies and procedures as part of this exhibit.

4.0 REGULATORY INCOME TAXES

General Requirements

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

Accounting Methodology

Prior to rate regulation, OPG utilized the liability method of accounting for income taxes and recorded both current and future income tax expense in accordance with Generally Accepted Accounting Principles. When OPG became subject to rate regulation on April 1, 2005, the taxes payable method of accounting for income taxes was adopted for the regulated operations in accordance with Generally Accepted Accounting Principles. This method was adopted because it is the method approved by the OEB for determining the tax allowance in the rates for regulated gas utilities and is specified in the Electricity Distributors Rate Handbook. Under the taxes payable method of accounting for income tax, only the current tax expense is recorded in the financial statements; future taxes are not recorded to the extent that they are recovered or refunded through regulated payment amounts.

In late 2007, the Canadian Institute of Chartered Accountants introduced certain changes to Generally Accepted Accounting Principles that will be effective on January 1, 2009. These changes will require all rate regulated entities to use the liability method of accounting for income taxes and, therefore, record future tax expense in the financial statements. In accordance with these changes to Generally Accepted Accounting Principles, OPG expects to record a regulatory asset or liability for the amount of future income taxes expected to be recovered or refunded through regulated payment amounts. Consistent with the use of the taxes payable method approved by the OEB for other regulated utilities (as noted above), OPG has not incorporated future tax expense into its revenue requirement.

Regulatory Income Taxes – Current Tax Expense

For purposes of establishing regulated payment amounts, OPG seeks recovery of current income tax expense only. The regulatory income taxes are determined by applying the statutory tax rate to regulatory taxable income of the combined nuclear and regulated hydroelectric operations as well as taxable income associated with the Bruce facilities. These income taxes are then allocated to nuclear (including the Bruce facilities) and regulated hydroelectric operations based on each business's regulatory taxable income. This approach reduces the total taxes included in the revenue requirement because if there is a tax loss in one regulated business unit, it reduces the tax expense in the other regulated business unit.

Regulatory taxable income is computed by making adjustments to the regulatory earnings before tax for items with different accounting and tax treatment, applying the same principles as used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. The most significant adjustments, as detailed in the calculation of taxable income/loss for the period 2005 - 2009 in Tables 7 and 8 accompanying this exhibit, are as follows:

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1. Depreciation/Capital Cost Allowance– Accounting depreciation expense is not deductible for tax purposes, however tax depreciation (i.e., capital cost allowance) is deductible. The capital cost allowance deduction for 2005 and subsequent years has been reduced to reflect the impact of adjustments resulting from an ongoing income tax audit of OPG by the Provincial Tax Auditors (the "Tax Auditors").
2. Nuclear Waste Management Expenses – OPG is responsible for decommissioning its nuclear stations and nuclear used fuel and low-level and intermediate-level waste management (collectively, the "Nuclear Liabilities") as described in Ex. H1-T1-S1. Expenses accrued relating to this obligation are not deductible for tax purposes.
3. Cash Expenditures for Nuclear Waste and Decommissioning – Cash expenditures incurred and charged against the Nuclear Liabilities are deductible for tax purposes.
4. Segregated Fund Contributions and Receipts – OPG is required under the Ontario Nuclear Fuel Act to make contributions to segregated funds to enable it to meet its obligations for the Nuclear Liabilities, as described in Ex. H1-T1-S1. *The Electricity Act, 1998* allows OPG a tax deduction when the contributions are made. When OPG receives monies from the funds for reimbursement of eligible expenditures, the amount received is taxable.
5. Adjustment Related to Duplicate Interest Deduction – This adjustment removes a portion of interest related to OPG's Nuclear Liabilities since this interest is included in both OPG's tax deduction for segregated nuclear fund contributions and the tax deduction associated with the deemed interest expenses financing OPG's rate base. The adjustment is determined based on the debt ratio and cost of debt from Ex. C1-T2-S1, and an assessment of the portion of OPG's rate base related to the Nuclear Liabilities.
6. Pension/Other Post-Employment Benefits – Pension and other post-employment benefits expenses recorded by OPG for accounting purposes (as discussed in Ex. F3-S4-T1) are not deductible for tax purposes. However, cash contributions to the registered pension plan, as well as OPEB and the supplementary pension plan payments are deductible for tax purposes.
7. Regulatory Assets and Liabilities – Certain expenditures recorded by OPG as regulatory assets for accounting purposes are considered to be operating expenses for tax

purposes and can be deducted in the year incurred. These expenses are recovered from ratepayers in future test periods in accordance with the direction provided by the OEB and the benefit of the tax deduction is recognized in the year these expenses are recovered (and recorded as amortization expense for accounting purposes). For instance, tax deductible costs incurred to increase the output of, refurbish or add operating capacity to a generation facility are recorded as a regulatory asset for accounting purposes and are not deducted as an operating expense as part of the calculation of the regulatory taxable income during the historical and bridge periods. Amounts recorded in the Nuclear Development Deferral Account and the Capacity Refurbishment Variance Account will be deducted for regulatory taxable income purposes during the test period based on the recovery amount/methodology approved by the OEB.

As an exception to the above principle, Pickering A return to service ("PARTS") expenses recorded by OPG as a regulatory asset in the PARTS deferral account described in Ex. J1-T1-S1 were deducted as an operating expense in the calculation of the regulatory taxable income in the year the expenses were actually incurred. Therefore, the amortization of the PARTS regulatory asset is added back for the purposes of calculating the regulatory taxable income, as the ratepayers will receive the tax benefit associated with these deferred costs through the application of the tax loss carry forward balance (discussed below) during the test period.

8. First Nations' Past Grievances Provision – Expenses recorded by OPG for accounting purposes as provisions for anticipated future expenditures are not deductible for tax purposes. Refer to Ex. F1-T2-S2 for a discussion of the First Nations' Past Grievances Provision.
9. Other – This category includes various miscellaneous tax adjustments such as the accrual for materials obsolescence, capital items that are expensed for accounting purposes, and meals and entertainment expenses that are subject to the 50 percent tax deduction limitation.
10. One Time Adjustments – Costs representing the impairment of inventory and construction in progress assets in 2005 as a result of OPG's decision not to proceed with

the return to service of Pickering A Units 2 and 3 were not recovered from the ratepayers. Consequently, the related amount deductible by OPG for tax purposes is added back in order to calculate the regulatory taxable income in 2005.

The regulatory taxable income calculation for the years 2005 - 2007 results in tax losses for those years, as shown in Ex. F3-T2-S1 Tables 7, 8 and 9. The actual cumulative tax losses at the end of 2007 that are available to be carried forward are $990.2M. These tax losses were generated mainly due to OPG's contributions to segregated funds, which are deductible for tax purposes under the *Electricity Act, 1998* and regulations there-under. OPG made annual contributions of $454M in 2005 - 2007 as well as a one-time additional payment of $334M in 2007 in accordance with the Ontario Nuclear Funds Agreement. This one-time payment was previously forecast to occur in the first quarter of 2008. (Refer to Ex. G2-T2-S1 for further detail on this payment.) In 2005, the $258M in PARTS expenses recorded as a regulatory asset were also deducted for tax purposes, as allowed under the *Income Tax Act* (Canada) contributing to a tax loss in that year. In 2007, OPG's negative earnings before taxes contributed to the tax loss in that year. OPG has forecasted higher regulatory earnings before tax for the test period and, accordingly, taxable income of $163.0M and $324.0M in 2008 and 2009, respectively. Table 9 accompanying this exhibit presents a continuity schedule of OPG's regulatory taxable income/losses.

Since OPG became subject to regulation on April 1, 2005, the annual regulatory tax loss for 2005 calculated as $364.4M in Ex. F3-T2-S1 Table 8 should be adjusted to remove the portion of the loss attributable to the period prior to regulation. The adjustment is based on a straight-line pro-ration with the exception of the loss resulting from the PARTS deferred costs deduction. The ratepayers receive the benefit of the full PARTS deferred costs deduction as O. Reg. 53/05 requires OPG to recover the full amount of these costs. The amount of the adjustment is a reduction to the loss of $28.4M, as reflected in Ex. F3-T2-S1 Table 9.

Typically, if a net tax loss arises in a particular year, it is carried forward to reduce regulatory taxable income in future years. OPG has applied its projected total cumulative tax losses at the end of 2007 to reduce the projected regulatory taxable income in 2008 and 2009 of

$163.0M and $324.0M, respectively, to nil. In this application, the projected tax losses are also used to mitigate the customer bill impact of OPG's payment amount and deferral/variance account recovery proposals. This mitigation proposal is described in Exhibit K.

Income Tax Audit

OPG is currently being audited by the Tax Auditors for the 1999 taxation year. In 2006 and 2008, OPG received preliminary communications from the Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of OPG's operations, or matters that were not addressed through the *Electricity Act, 1998*. Although OPG has resolved some of these issues, there is uncertainty as to the resolution of the remaining issues. OPG expects to receive a reassessment for its 1999 taxation year. Although this reassessment would relate to the 1999 taxation year, the potential impact of the reassessment could be to materially increase income taxes for the 2005 - 2009 period and subsequent years, and therefore reduce tax losses.

Regulatory Income Taxes – Large Corporations Tax

OPG was subject to the large corporations tax until it was eliminated by the federal government effective 2006. For the historical year 2005, large corporations tax was calculated by applying the applicable rate to the rate base in excess of the full large corporations tax exemption. The full exemption was attributed to regulated operations as part of the calculation, consistent with the determination of regulatory income taxes on a stand-alone basis. The calculation of large corporations tax presented in Tables 3 and 6 accompanying this exhibit includes an amount related to the Bruce facilities.

Ontario Corporate Minimum Tax

Ontario corporate minimum tax ("OCMT") is designed to impose a minimum tax based on financial statement income calculated without most tax adjustments. The OCMT paid in a year can be applied to reduce taxes payable in future years. The OCMT rate is substantially

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F3
Tab 2
Schedule 1
Table 7

Table 7
Calculation of Regulatory Income Taxes ($M)
Years Ending December 31, 2007, 2008 and 2009

Line No.	Particulars	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	Regulatory Earnings Before Tax[1]	(84.0)	472.0	504.0
2	Additions for Tax Purposes:			
3	Depreciation	387.0	408.0	443.0
4	Nuclear Waste Management Expenses	79.0	48.0	39.0
5	Receipts from Nuclear Segregated Funds	119.0	49.0	54.0
6	Pension and OPEB/SPP Accrual	384.0	353.0	337.0
7	Regulatory Asset Amortization - PARTS Deferred Costs	95.0	39.0	16.0
8	Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account	N/A	8.0	10.0
9	Regulatory Asset Amortization - Nuclear Liability Deferral Account	N/A	36.0	48.0
10	First Nations' Past Grievances Provision	27.0	0.0	0.0
11	Adjustment Related to Duplicate Interest Deduction	34.0	56.0	54.0
12	Other	22.0	11.0	12.0
13	Total Additions	1,147.0	1,008.0	1,013.0
	Deductions for Tax Purposes:			
14	CCA	316.0	311.0	314.0
15	Cash Expenditures for Nuclear Waste & Decommissioning	198.0	226.0	193.0
16	Contributions to Nuclear Segregated Funds	788.0	454.0	350.0
17	Pension Plan Contributions	211.0	233.0	239.0
18	OPEB/SPP Payments	58.0	68.0	73.0
19	Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account	N/A	7.0	10.0
20	Regulatory Asset Deduction - Nuclear Liability Deferral Account	N/A	1.0	1.0
21	Other	45.0	17.0	13.0
22	Total Deductions	1,616.0	1,317.0	1,193.0
23	Regulatory Taxable Income/(Loss) Before Loss Carry-Over	(553.0)	163.0	324.0
24	Tax Loss Carry-Over to Future Years / (from Prior Years)[2]	553.0	(163.0)	(324.0)
25	Regulatory Taxable Income After Loss Carry-Over	0.0	0.0	0.0
26	Income Tax Rate	34.12%	31.50%	31.00%
27	Total Regulatory Income Taxes	0.0	0.0	0.0
	Tax Rates:			
28	Federal Tax	21.00%	19.50%	19.00%
29	Federal Surtax	1.12%	0.00%	0.00%
30	Provincial Tax	14.00%	14.00%	14.00%
31	Manufacturing & Processing Profits Deduction	-2.00%	-2.00%	-2.00%
32	Total Income Tax Rate	34.12%	31.50%	31.00%

1 Reconciliation of regulatory EBT for 2007 to the audited financial statements is presented in Exhibit C1-T2-S1.
2 Refer to Ex. F3-T2-S1 Table 9 for a continuity schedule of regulatory tax losses.

Numbers may not add due to rounding.

Table 8
Calculation of Regulatory Income Taxes ($M)
Year Ending December 31, 2005 and Year Ending December 31, 2006

Line No.	Particulars	2005 Actual	2006 Actual
		(a)	(b)
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[1]	106.0	193.8
2	**Additions for Tax Purposes:**		
3	**Depreciation**	421.0	404.0
4	**Nuclear Waste Management Expenses**	34.0	38.0
5	**Receipts from Nuclear Segregated Funds**	23.0	19.0
6	**Pension and OPEB/SPP Accrual**	234.0	374.0
7	**One-Time Adjustment: P2P3 Inventory Write-offs**	49.0	N/A
8	**One-Time Adjustment: P2P3 CIP Write-offs**	38.0	N/A
9	**Regulatory Asset Amortization - PARTS Deferred Costs**	4.0	25.0
10	**Adjustment Related to Duplicate Interest Deduction**	45.0	38.0
11	**Other**	48.0	20.0
12	**Total Additions**	896.0	918.0
	Deductions for Tax Purposes:		
13	**CCA**	317.0	318.0
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	84.0	153.0
15	**Contributions to Nuclear Segregated Funds**	454.0	454.0
16	**Pension Plan Contributions**	197.9	207.0
17	**OPEB/SPP Payments**	38.0	55.0
18	**Regulatory Asset Deduction - PARTS Deferred Costs**	258.0	13.0
19	**Other**	17.5	13.0
20	**Total Deductions**	1,366.4	1,213.0
21	**Regulatory Taxable Income/(Loss) Before Loss Carry-Over**	(364.4)	(101.2)
22	**Tax Loss Carry-Over to Future Years / (from Prior Years)**[2]	364.4	101.2
23	**Regulatory Taxable Income After Loss Carry-Over**	0.0	0.0
24	**Income Tax Rate**	34.12%	34.12%
25	**Regulatory Income Taxes**	0.0	0.0
	Calculation of Regulatory Income Taxes		
26	**Regulatory Income Taxes** (line 25)	0.0	0.0
27	**Large Corporations Tax - Nuclear** (Ex. F3-T2-S1 Table 6)	5.7	0.0
28	**Large Corporations Tax - Reg. Hydro.** (Ex. F3-T2-S1 Table 3)	7.0	0.0
29	**Total Regulatory Income Taxes**	12.7	0.0
	Tax Rates:		
30	**Federal Tax**	21.00%	21.00%
31	**Federal Surtax**	1.12%	1.12%
32	**Provincial Tax**	14.00%	14.00%
33	**Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
34	**Total Income Tax Rate**	34.12%	34.12%

1 Reconciliation of regulatory EBT to the audited financial statements is presented in Exhibit C1-T2-S1.
2 Refer to Ex. F3-T2-S1 Table 9 for a continuity schedule of regulatory tax losses.

Numbers may not add due to rounding.

Table 9
Summary of Regulatory Tax Losses ($M)
Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Particulars	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**	N/A	(336.0)	(437.2)	(990.2)	(827.2)
2	**Income/(Loss) for the Year**	(364.4)	(101.2)	(553.0)	163.0	324.0
3	**Allocation to Period Prior to Regulation**[1]	28.4				
4	**Loss Carried Forward**	(336.0)	(437.2)	(990.2)	(827.2)	(503.2)

1 See Ex. F3-T2-S1 for discussion of allocation of 2005 loss to period prior to regulation.

Exhibit J - Variance & Deferral Accounts

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- Any differences that result from tax assessments or re-assessments (including reassessments associated with the application of these rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

As discussed in Ex. F3-T2-S1, OPG is currently being audited by the Provincial Tax Auditors. Based on a preliminary communication from the Tax Auditors with respect to their initial findings, OPG expects to receive a reassessment that may result in an increase to income taxes. This event is beyond OPG's control. OPG expects that the reassessment may result in a material financial impact; however the amount of the ultimate settlement is not predictable with sufficient accuracy to include it in OPG's forecast. Including a reassessment value in its forecast would reduce the tax loss carry forward amount. OPG has applied these tax loss carry forward amounts to reduce income tax expense during the test period, and to mitigate the consumer impact of OPG's revenue requirement proposals as described in Ex. F3-T2-S1 and Exhibit K.

OPG notes that in December 2005, the OEB issued a communication (Response to Frequently Asked Questions with respect to the Accounting Procedures Handbook for the Electricity Distribution Utilities – Response #19) that allowed regulated electric distributors to use Account 1592, 2006 Payments In Lieu and Taxes Variances, to capture the tax impact a number of items including "any differences that result from a legislative or regulatory change to the tax rates or rules assumed" and "any differences that result from a change in, or a disclosure of, a new assessing or administrative policy "as well as specified tax re-assessments.

OPG forecasts taxes and payments in lieu of taxes (where applicable) for the test period based on the enacted tax rates and laws currently in effect. OPG has not forecast the impact of potential changes in laws, tax rates, rules or reassessments pursuant to these rules (e.g., potential amendment to O. Reg. 224/00 pursuant to the *Electricity Act, 1998* impacting the amount of payments in lieu of property taxes is discussed in Ex. F3-T2-S1). All these matters are beyond the control of OPG.

Exhibit K - Mitigation of Payment Amount Increases

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MITIGATION OF PAYMENT AMOUNT INCREASES

OPG's revenue requirement forecast as presented in Ex. K1-T1-S1 summarizes the revenue and expense evidence for OPG's 21 month test period for the nuclear and regulated hydroelectric facilities. OPG recognizes that the revenue requirement increase over the current payment amounts is significant and will have an impact on electricity consumers. OPG proposes to mitigate this impact by crediting the benefit associated with certain tax losses accumulated over the interim period to consumers in the test period.

As detailed in Ex. F3-T2-S1, the regulatory taxable income calculation for the years 2005 - 2008 results in tax losses for those years. OPG has used the accumulated tax losses at the end of 2008 to reduce the regulatory taxable income for 2009 to nil. The projected remaining balance of regulated tax losses is $503.2M at the end of 2009.

Absent any mitigation, OPG would propose to carry forward this balance to reduce regulatory taxable income in future years until no tax loss balance remained. To mitigate the increase in payment amounts in this application, OPG proposes to accelerate the application of the available tax losses to reduce the test period revenue requirement. This mitigation approach results in the application of the associated tax loss balance multiplied by the 2009 income tax rate of 32 percent (see Ex. F3-T2-S1 Table 7) to revenue requirement in the test period. This results in a reduction to the revenue requirement of $228M. This mitigation approach results in a 14.8 percent increase in the payment amounts, as opposed to an 19.0 percent increase without mitigation.

OPG proposes to apply the mitigation associated with the tax loss carry forward balance to its nuclear and regulated hydroelectric payment amounts to achieve a consistent payment amount increase across the two technologies. This application results in a reduction of regulated hydroelectric revenue requirement of $90.1M and a reduction in the nuclear revenue requirement of $137.9M. The offset in revenue requirement associated with mitigation is used in the calculation of the regulated hydroelectric and nuclear payment amounts as presented in Ex. K1-T2-S1 and Ex. K1-T3-S1, respectively.

Table 1
Summary of Revenue Requirement ($M)
April 1, 2008 to December 31, 2008

Line No.	Description	Note	Regulated Hydroelectric 2008	Regulated Hydroelectric Adjustment (Note 1)	Regulated Hydroelectric 2008 (Apr. 1-Dec. 31)	Nuclear 2008	Nuclear Adjustment (Note 1)	Nuclear 2008 (Apr. 1-Dec. 31)	Total 2008 (Apr. 1-Dec. 31)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Rate Base								
1	**Net Fixed Assets**	2	3,863.1	(5.2)	3,857.8	2,794.0	(6.3)	2,787.7	6,645.5
2	**Working Capital**	2	0.6	0.0	0.6	705.4	0.0	705.4	706.0
3	**Cash Working Capital**	2	21.8	0.0	21.8	16.0	0.0	16.0	37.8
4	**Total Rate Base**		3,885.5	(5.2)	3,880.2	3,515.4	(6.3)	3,509.1	7,389.3
	Capitalization								
5	**Short-term Debt**	3	99.4	0.0	99.4	89.9	0.0	89.9	189.3
6	**Long-Term Debt**	3	1,551.9	(2.3)	1,549.7	1,404.1	(2.7)	1,401.4	2,951.1
7	**Common Equity**	3	2,234.1	(3.0)	2,231.1	2,021.4	(3.6)	2,017.7	4,248.9
8	**Total Capital**		3,885.5	(5.3)	3,880.2	3,515.4	(6.3)	3,509.1	7,389.3
	Cost of Capital								
9	**Short-term Debt**	4	5.8	0.0	5.8	5.2	0.0	5.2	11.0
10	**Long-Term Debt**	4	89.3	(23.8)	65.4	80.8	(21.6)	59.2	124.6
11	**Return on Equity**	4	234.6	(58.9)	175.7	212.2	(53.3)	158.9	334.6
12	**Total Cost of Capital**		329.7	(82.7)	246.9	298.3	(74.9)	223.3	470.3
	Expenses								
13	**OM&A**	5	119.0	(25.9)	93.1	2,184.6	(521.9)	1,662.7	1,755.8
14	**Fuel and GRC**	6	228.2	(48.3)	179.9	162.4	(36.7)	125.7	305.6
15	**Depreciation & Amortization**	7	61.5	(15.6)	45.9	350.1	(72.8)	277.2	323.2
16	**Property and Capital Taxes**	8	8.7	(2.2)	6.5	21.8	(5.5)	16.3	22.9
17	**Total Expenses**		417.4	(92.0)	325.4	2,718.8	(636.8)	2,082.0	2,407.4
	Less:								
	Other Revenues								
18	**Bruce Lease Revenues Net of Direct Costs**	9	N/A	N/A	N/A	69.1	(17.4)	51.8	51.8
19	**Ancillary and Other Revenue**	10	32.4	(8.1)	24.3	65.5	(16.0)	49.4	73.8
20	**Total Other Revenues**		32.4	(8.1)	24.3	134.6	(33.4)	101.2	125.5
21	**Income Tax**	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Revenue Requirement**		714.7	(166.7)	548.0	2,882.5	(678.4)	2,204.1	2,752.1

Notes:

1 Adjustment to remove activity from January 1, 2008 to March 31, 2008 as described in Ex. K1-T1-S1
2 Ex. B1-T1-S1 Table 1 (Reg. Hydro), Ex. B1-T1-S1 Table 2 (Nuclear)
3 Totals from Ex. C1-T2-S1 Table 3 (Column (a))
Capitalization is allocated to Regulated Hydroelectric and Nuclear operations using rate base.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-T2-S1 Table 3
4 Totals from Exhibit C1-T2-S1 Table 3 (Column (d))
Cost of Capital is allocated to Regulated Hydroelectric and Nuclear operations using rate base.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-T2-S1 Table 3
5 Ex. F1-T1-S1 Table 1 (Reg. Hydro), Ex. F2-T1-S1 Table 1 (Nuclear). Nuclear adjustment includes $25M deferred from Q1 and treated as a regulatory asset.
6 Ex. F1-T4-S1 Table 1 (Reg. Hydro), Ex. F2-T5-S1 Table 1 (Nuclear)
7 Reg. Hydro: Ex. F3-T2-S1 Table 1 (OM&A Dep'n & Amort.) plus Ex. J1-T2-S1 Table 2 (Deferral & Variance Account Amort.)
Nuclear: Ex. F3-T2-S1 Table 4 (OM&A Dep'n & Amort.) plus Ex. J1-T2-S1 Table 3 (Deferral & Variance Account Amort.)
8 Ex. F3-T2-S1 Table 1 (Reg. Hydro), Ex. F3-T2-S1 Table 4 (Nuclear)
9 Revenues from Ex. G2-T2-S1 Table 1 less Direct Costs from Ex. G2-T2-S1 Table 3
10 Ex. G1-T1-S2 Table 1 (Reg. Hydro), Ex. G2-T1-S1 Table 1 (Nuclear)

Numbers may not add due to rounding.

Table 2
Summary of Revenue Requirement ($M)
January 1, 2009 to December 31, 2009

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total 2009
			(a)	(b)	(c)
	Rate Base				
1	**Net Fixed Assets**	1	3,847.5	2,696.0	6,543.5
2	**Working Capital**	1	0.6	771.8	772.4
3	**Cash Working Capital**	1	21.8	16.0	37.8
4	**Total Rate Base**		3,869.9	3,483.8	7,353.7
	Capitalization				
5	**Short-term Debt**	2	99.6	89.7	189.3
6	**Long-Term Debt**	2	1,545.0	1,390.9	2,936.0
7	**Common Equity**	2	2,225.2	2,003.2	4,228.4
8	**Total Capital**		3,869.9	3,483.8	7,353.7
	Cost of Capital				
9	**Short-term Debt**	3	6.0	5.4	11.3
10	**Long-Term Debt**	3	91.5	82.4	173.8
11	**Return on Equity**	3	233.6	210.3	444.0
12	**Total Cost of Capital**		331.1	298.1	629.1
	Expenses				
13	**OM&A**	4	119.0	2,168.7	2,287.7
14	**Fuel and GRC**	5	244.1	204.2	448.2
15	**Depreciation & Amortization**	6	61.6	388.9	450.5
16	**Property and Capital Taxes**	7	8.7	22.0	30.7
17	**Total Expenses**		433.4	2,783.8	3,217.1
	Less:				
	Other Revenues				
18	**Bruce Lease Revenues Net of Direct Costs**	8	N/A	82.6	82.6
19	**Ancillary and Other Revenue**	9	33.1	50.9	84.0
20	**Total Other Revenues**		33.1	133.4	166.6
21	**Income Tax**	7	0.0	0.0	0.0
22	**Revenue Requirement**		731.3	2,948.4	3,679.7

Notes:
1 Ex. B1-T1-S1 Table 1 (Reg. Hydro), Ex. B1-T1-S1 Table 2 (Nuclear)
2 Totals from Ex. C1-T2-S1 Table 2 (Column (a))
Capitalization is allocated to Regulated Hydroelectric and Nuclear operations using rate base.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-T2-S1 Table 2
3 Totals from Ex. C2-T1-S1 Table 2 (Column (d))
Cost of Capital is allocated to Regulated Hydroelectric and Nuclear operations using rate base.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-T2-S1 Table 2
4 Ex. F1-T1-S1 Table 1 (Reg. Hydro), Ex. F2-T1-S1 Table 1 (Nuclear)
5 Ex. F1-T4-S1 Table 1 (Reg. Hydro), Ex. F2-T5-S1 Table 1 (Nuclear)
6 Reg. Hydro: Ex. F3-T2-S1 Table 1 (OM&A Dep'n & Amort.) plus Ex. J1-T2-S1 Table 2 (Deferral & Variance Account Amort.)
Nuclear: Ex. F3-T2-S1 Table 4 (OM&A Dep'n & Amort.) plus Ex. J1-T2-S1 Table 3 (Deferral & Variance Account Amort.)
7 Ex. F3-T2-S1 Table 1 (Reg. Hydro), Ex. F3-T2-S1 Table 4 (Nuclear)
8 Revenues from Ex. G2-T2-S1 Table 1 less Direct Costs from Ex. G2-T2-S1 Table 3
9 Ex. G1-T1-S2 Table 1 (Reg. Hydro), Ex. G2-T1-S1 Table 1 (Nuclear)

Numbers may not add due to rounding.

Table 1
Payment Design - Regulated Hydroelectric
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period
		(a)
1	**Revenue Requirement ($M)**	1,279.3
2	**Less: Mitigation ($M)**[1]	90.1
3	**Requested Revenue Requirement Recovery ($M)**	1,189.2
	(line 1 - line 2)	
	PAYMENT AMOUNT:	
4	**Requested Revenue Requirement Recovery ($M)**	1,189.2
	(line 3)	
5	**Forecast Production (TWh)**[2]	31.5
6	**Payment Amount ($/MWh)**	37.8
	(line 4 / line 5)	

Notes:

1 Inclusion of tax losses applicable to future periods as described in Ex. K1-T1-S1

2 From Ex. K1-T1-S1 Table 3 (line 1, columns (a)+(d))

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit K1
Tab 3
Schedule 1
Table 1

Table 1
Payment Design - Nuclear
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period
		(a)
1	**Revenue Requirement ($M)**	5,152.5
2	**Less: Mitigation ($M)**[1]	137.9
3	**Requested Revenue Requirement Recovery ($M)**	5,014.6
	(line 1- line 2)	
4	**Less: Amortized Amount for Deferral & Variance Accounts ($M)**	128.1
5	**Revenue Requirement to be Recovered Through Payment Amounts ($M)**	4,886.5
	(line 3 - line 4)	
	FIXED MONTHLY PAYMENT AMOUNT:	
6	**Proposed Fixed Recovery**[2]	25%
7	**Fixed Recovery Amount ($M)**	1,221.6
	(line 5 * line 6)	
8	**Fixed Monthly Payment ($M)**	58.2
	(line 7 / 21 months)	
	VARIABLE PAYMENT AMOUNT:	
9	**Remaining Revenue Requirement ($M)**	3,664.9
	(line 5 - line 7)	
10	**Forecast Production (TWh)**[3]	88.2
11	**Variable Payment ($/MWh)**	41.5
	(line 9 / line 10)	
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER AMOUNT:	
12	**Payment Rider ($/MWh)**[4]	1.45

Notes:
1 Inclusion of tax losses applicable to future periods as described in Ex. K1-T1-S1
2 Per Ex. I-T1-S1
3 From Ex. K1-T1-S1 Table 3 (line 1, columns (b)+(e))
4 From Ex. J1-T2-S1 Table 3

TAB 3

Board Staff Interrogatory #115

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

OPG's application (K1-T1-S2 and K1-T1-S3-Table 1) indicates that the proposed revenue requirement for the 21-month period ended December 31, 2009 has been reduced by $228 million through application of "certain tax losses accumulated over the interim period." At the February 6, 2008 hearing on the issues list, OPG's counsel stated the following in respect of tax losses:

... there actually are not corporate tax losses anymore. They were actually used. But what we have done is, because we understood that the regulated assets were to be treated on a stand-alone basis, we have notionally preserved those tax loss carry-forwards that were attributable to the regulated business, and even though they "corporately" actually don't exist anymore, we are giving the customers of [sic] the benefits of those tax loss carry forwards. [Transcript, February 6, 2008, pp. 38 and 39]

a) Please confirm that OPG does not currently have any tax loss carry forwards that can be applied to reduce PILs payments required in 2008 and later years.

b) If OPG, as the corporate entity that pays PILs, does not have any tax loss carry forwards, does that mean that any tax losses incurred by the prescribed assets in 2005 through 2007 have been used to reduce PILs payments that otherwise would have been made by OPG in those years? If that is correct, how can the benefits of those losses be used twice – once to reduce corporate PILs payments in 2005 through 2007, and again to reduce PILs payments in respect of earnings from the prescribed assets in 2008 and 2009?

Response

a) As at December 31, 2007, OPG, as a corporate entity, has no tax loss carry forwards that can be applied to reduce PILs payments required in 2008 or later years.

b) OPG's prescribed and non-prescribed assets are in the same corporate entity. Therefore, any actual tax losses incurred by the prescribed assets in 2005 through 2007 would automatically offset any actual taxable income generated by the non-prescribed assets and, accordingly, would reduce PILs payments by OPG as a whole. There are no actual corporate tax losses available to reduce PILs payments by OPG, as a single corporate entity, in 2008 or later years. However, as stated by OPG's counsel at the hearing on February 6, 2008 and as noted in Section 4.0, Ex. F3-T2-S1, for the purposes of this Application OPG has calculated regulatory tax losses that have been generated by the prescribed assets on a stand-alone basis since April 1, 2005. These losses are used to reduce OPG's regulatory taxes as part of the proposed revenue requirement calculation for the benefit of the ratepayers through lower payment amounts in 2008 and 2009. The application of these losses to reduce OPG's revenue requirement for the test period has no direct impact on the actual amount of PILs payments that will be required in 2008 and later years by OPG as a corporate entity.

Board Staff Interrogatory #116

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

Starting April 1, 2005, OPG began accounting for income taxes (PILs) related to the prescribed assets using the taxes payable method, rather than the liability method that is required to be used by most commercial companies. Per Note 11 (page 36) of OPG's 2007 financial statements, it appears that had the company followed the liability method of accounting, its December 31, 2007 balance sheet would have included an additional future tax liability of $436 million (the difference between a $205 million liability as shown in the financial statements and a $641 million liability that would have been booked had the liability method been adopted).

a) Given that OPG's prescribed assets were not subject to regulation by the OEB in 2005, 2006, and 2007, please explain the rationale for following the taxes payable method in those years.

b) The unrecorded future income liability of $436 million referred to in the preamble to this question presumably will turn into a real PILs liability in future periods as the temporary differences between book and tax deductions start to reverse. Is OPG proposing that those taxes be included in future payment amounts for the prescribed assets approved by the Board? If so, please explain why is it appropriate for electricity consumers in future periods to pay for a tax liability that OPG chose not to recognize in 2005, 2006, and 2007?

Response

a) Although OPG's prescribed assets were not regulated by the OEB during 2005, 2006 and 2007, OPG considers that they were regulated assets under the terms of O. Reg. 53/05.

   In the information provided to the Province for its use in setting the payment amounts during 2005, 2006 and 2007, OPG used the taxes payable method and therefore did not include future income tax expense in the submission. This approach was consistent with the treatment that OPG expected the OEB to adopt when the Board assumed authority to regulate OPG in 2008. The use of the taxes payable method was endorsed by CIBC World Markets, the advisors hired by the Province to assist it with setting the interim payment amounts.

OPG notes that the use of the taxes payable method is consistent with established OEB regulatory principles for regulated gas utilities as well as the guidance set out in the OEB's Electricity Distributors Rate Handbook.

Accordingly, OPG is of the view that upon becoming subject to regulation by the OEB, future income taxes not recovered through payment amounts established by O. Reg. 53/05 will be recovered through payment amounts established by the OEB (once these future income taxes translate into PILs through reversal of temporary differences).

In addition, OPG notes that the Canadian Institute of Chartered Accountants ("CICA") Handbook ("HB") Section 3465, Income Taxes, paragraph 102 states that: "A rate-regulated enterprise need not recognize future income taxes in accordance with this Section to the extent that future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers..."

In accordance with the above paragraph, OPG elected to follow, for financial reporting purposes, the taxes payable method for its regulated operations effective April 1, 2005 and therefore has not recognized future income taxes during 2005, 2006 and 2007 to the extent that such future taxes are expected to be included in future regulated prices.

OPG made this election because OPG became a rate-regulated enterprise on April 1, 2005 as defined by Canadian Generally Accepted Accounting Principles ("GAAP") in CICA HB Section 1100, Generally Accepted Accounting Principles, paragraph 36.

b) Yes, OPG is proposing that these taxes be recovered in future payment amounts set by the Board. OPG's proposal is consistent with OEB practice as well as the application of the intergenerational equity principle in the OEB Electricity Distributors Rate Handbook that requires recovery of income taxes in the period they are actually incurred rather than when they are recognized as a future income tax expense for accounting purposes. As noted above, OPG did not include future income taxes in the information provided to the Province for the determination of payment amounts under O. Reg. 53/05. Therefore, OPG should be entitled to the recovery of the actual PILs related to these future income taxes that were not recovered during the period from April 1, 2005 to the effective date of the OEB's first order.

OPG's proposal is also consistent with OPG's view that ratepayers are entitled to the benefit of regulatory income tax losses generated by the regulated operations since April 1, 2005, as discussed in Ex. F3-T2-S1. The amount of the regulatory tax losses generated during the period from April 1, 2005 to December 31, 2007 is $990.2M (Table 9, Ex. F3-T2-S1), which translates into an approximate benefit to consumers of $312M (at the tax rate of 31.50 percent, which is in effect for 2008). OPG also notes that the entire benefit of these tax losses is being credited to consumers over the current 21-month test period (Ex. K1-T1-S2), whereas the temporary differences cited in the interrogatory will likely reverse over a significantly longer period of time.

Board Staff Interrogatory #119

Ref: Ex. K1-T1-S2, page 1, lines 7-23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

OPG proposes to use its accumulated income tax losses to mitigate the increase in payment amounts by reducing the revenue requirements. OPG's application applies these tax losses so that there is a consistent payment amount increase across the two generation technologies.

a) Could these tax losses be applied differently to reduce one revenue requirement proportionally more than the other? Has OPG investigated alternative allocations?

b) If these tax losses were allocated to the two revenue requirements in a different manner would there be substantial differences in the mitigation impacts?

Response

a) The tax losses could be applied differently. OPG applied the tax losses to equalize the percentage rate increase for each technology. OPG has not investigated any alternative allocations.

b) Whether or not there would be substantial difference in mitigation impacts would depend on the manner in which the tax losses were allocated between the two technologies. The mitigation of the combined revenue requirement would still be the same, although the payment amounts for the two technologies would be different than those set out in OPG's application.

Board Staff Interrogatory #121

Ref: Ex. K1-T1-S2, page 1, lines 7-23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

Please provide a non-capital loss carry-forward continuity schedule for income tax purposes on company-wide basis, allocated to the prescribed assets showing the origination of losses by year and their application to other years' taxable income. (F3/T2/S/Table 9)

Response

OPG has provided a continuity schedule of regulatory tax loss carry-forwards for the period 2005 to 2009 for its regulated operations for the purposes of establishing payment amounts in Table 9 Ex. F3-T2-S1.

There were no actual tax losses generated by the unregulated operations during 2005-2007, as noted in the response to interrogatory L-1-122. In addition, as noted in the response to interrogatory L-1-115(a), OPG does not have any actual tax loss carry-forward amounts available at the end of 2007 on a company-wide basis. OPG also does not expect to incur actual tax losses during the test period on a company-wide basis.

Information related to tax losses, if any, incurred by OPG prior to 2005 is not relevant for the determination of payment amounts for OPG's regulated operations.

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Board Staff Interrogatory #122

Ref: Ex. K1-T1-S2, page 1, lines 7 - 23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

Are losses arising from the non-regulated business segments in prior years being proposed to reduce/eliminate regulatory taxable income of the regulated business segments in 2008 and 2009? If so, provide the breakdown of these amounts being applied and the rationale for this treatment.

Response

There were no tax losses generated by the non-regulated business segments during 2005-2007.

TAB 4

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MR. STAINES: It varies. It varies depending on the circumstances.

MR. CHUTE: Okay.

MR. STAINES: A lot of the -- the head-office costs that it can be directly assigned to a prescribed facility or unprescribed facility as well.

MR. CHUTE: Right. Okay. Well, I take it that that's an opinion of OPG that you can't assign a revenue from export sales to any particular asset. That's just a --

MR. PENNY: I think that is more than an opinion. I think what we're saying is that when OPG engages in the export market, it's engaging in the export market not as an owner of prescribed facilities, but like anybody else, and it buys in the export market like anybody else. And we're not assigning any of those costs to the regulated facilities.

I don't see that as a matter of opinion. I see it as a matter of fact. But, you know, I think maybe we're into the realm of argument at this stage.

MR. CHUTE: Possibly. Okay. That's fine. Thanks.

MR. PENNY: Let's flip the page, then. We'll get to -- Mr. Thompson's been interested in this issue, so we'll flip to page 11 and questions arising from CME. I think the first one assigned to this panel is on the first page, page 11.

MR. BARRETT: Yes, that's correct. The part A question asks about the connection between the company's business plans and resulting customer bill impacts.

The regulatory framework that was established by the government envisioned that OPG would apply to the OEB for new rates after April 1, 2008, set on a just and reasonable basis, and that is what we have done.

The application is based on the company's approved business plans and a rate of return consistent with the company's commercial mandate.

In going through the business planning process, the company focuses on deciding how much it needs to officially operate its assets over the planning period and to respect the commercial mandate that it has from its shareholder.

The company is mindful of the impact of the proposed increase, and that's one of the reasons that we had proposed mitigation in the application, essentially an accelerated return of tax losses that have accumulated over the interim period. And there's evidence on that in the application.

MR. PENNY: Why don't we flip the page, page 12, part B.

MR. BARRETT: part B asks us to -- using a chart that was provided in the materials -- try and estimate a bill impact for a large industrial customer. In the application we have provided customer impact for a typical residential customer, and that impact is in the order of 2.7, 3 percent. But if you use the chart that is provided on page 14 of the handout materials, that chart shows --

MR. PENNY: Just so we're clear, you're talking about the bundle that we're using?

sensitivity of that information.

Is there any follow-up?

MR. THOMPSON: When Michael finishes his piece. I was waiting for the...

MR. PENNY: That's all we have on that particular issue, so if you have particular questions, or do you want to just --

MR. THOMPSON: I was going to wait until you get through everything, and then I'll do my bit.

MR. PENNY: Yes, that's fine.

So let's move on then to part C. I'm sorry. I'm going backwards. We're moving on to item 4, the last of the four questions. And that, I think we have a written response, which is, according to my numbering, page 6 of the -- of Exhibit KT1.1, which is labelled "CME question 4".

MR. PENNY: If everybody's got that turned up, Mr. Barrett, if you want to walk through this?

MR. BARRETT: Yes. Thank you.

We were asked to provide the impact of various common equity and ROE combinations. These are identified as 4(a), (b), and (c). And as I read this interrogatory or this supplemental question, these proposed equity ratios and ROEs relate to certain of the expert evidence that's been filed in this case by various intervenors.

So if you look at the response, there's two tables that are provided. In the first table, we have provided the impact on the test-period revenue requirement in millions of dollars. And there are columns for both nuclear, hydro, and total, or all regulated.

And just stepping through -- and again, this is against the company's proposals in this filing, which are a 57.5 percent equity slice and a 10.5 percent return on equity.

So if you look at alternative A, which is a 60/40 debt/equity, and a 7.75 percent ROE, you see that the impact on the revenue requirement is a reduction of $284-million, as an example from that first table.

The second table looks at the deficiency, the impact of these same recommendations on the deficiency. And again, looking at the A line as an example of the numbers in the table, you will see the same $284-million impact on the deficiency. It simply flows through.

And just to be clear, there's a little footnote that these revenue requirement impacts do not reflect the application of changes in tax losses or any of the associated mitigation, because, as you will note from the evidence, the actual deficiency that the company is seeking is net of mitigation.

MR. PENNY: And just to clarify that, Mr. Barrett, if the revenues associated with ROE from either changes in capital structure or return are changed, does that affect the ability of OPG to use the tax losses in the test period, or...?

MR. BARRETT: It affects the amount of tax losses --

MR. PENNY: Yes.

MR. BARRETT: -- that would be available for mitigation.

MR. PENNY: Right. Thank you.

So that was the CME questions. I think, Peter, if you have follow-up, do you want to do it now, or are you -- all right. So we'll vary it. Okay. That's fine.

So that would take us, I think, next to page 15, and the follow-up with respect to Exhibit L14-4.

MR. BARRETT: Yes, and this is a question, we were asked whether we had any regulatory precedents for the pension and OPEB cost variance account that has been proposed in the evidence. As a consequence of that supplemental question, we did some additional research and did identify some precedents, which I can just identify for you.

I understand from the results of that research that Northland Utilities, which is a utility based in the Northwest Territories, a relatively small utility, has proposed a very similar type of account. I don't believe there is a decision yet in that case.

And I'm also advised that Terasen Gas, British Columbia, has a similar, but not exactly the same type of account. I believe that's an existing account.

MS. CAMPBELL: And your information is for what time period? Are these recent decisions?

MR. BARRETT: The Northland Utilities application that I referenced, as I understand it -- or the materials that I have have a date of February 8, 2008. So it's a very

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MS. CAMPBELL: KT1.1.

MR. PENNY: KT, sorry, KT1.1. That's the one where the first page is participating argument made.

MR. THOMPSON: Right. And if you would go through to, I think it's page 6, where you provided the revenue-requirement impacts and the revenue-deficiency impacts of the capital ratio ROE scenarios that were presented in our question.

And just to get everything in one place that will help us here, if you could turn up two other documents. One is Exhibit K1, tab 3, Schedule 1, Table 1.

MR. BARRETT: Yes, I have it.

MR. THOMPSON: Okay. And then there was a document filed, I think it was yesterday. It was some updated responses, updated information. And there's -- in there, there is a response to a CCC interrogatory dealing with the drivers of the deficiency. It's CCC Interrogatory Number 49, Exhibit L, tab 3, Schedule 49.

MR. BARRETT: That's an updated version of that IR? Does it have a date on it?

MR. THOMPSON: That one has updated, looks like "05 of 09". I got this, I think, yesterday.

MS. REUBER: So, yes, it was sent by e-mail, the updates. I believe our sets are actually updated. But I have the page there.

MR. BARRETT: Okay. I have that.

MR. THOMPSON: Okay. So just to put this in context, so the -- starting with CME for revenue requirement for nuclear is 5.153-billion, and hydroelectric, 1.282-billion.

MR. BARRETT: That's correct, on an unmitigated basis.

MR. THOMPSON: And we see those same numbers in this CCC document, Exhibit L, tab 3, Schedule 49, in the second column, for the totals. Updated submissions, required revenue, 1,282, and then for nuclear, 5,153?

MR. BARRETT: Yes, I see that.

MR. THOMPSON: You with me?

MR. BARRETT: Yeah.

MR. THOMPSON: And then back in the CME document for revenue deficiency, we have nuclear, 785, and hydroelectric, 244-million, and we see those same numbers for hydro and nuclear in the CCC exhibit, in the third column. Are you with me?

MR. BARRETT: I am.

MR. THOMPSON: Okay. And then looking at your Exhibit K, tab 3, Schedule 1, Table 2, we have the revenue requirement for nuclear at the 5,152.5, which has been rounded to 5,153 in the other exhibits.

MR. BARRETT: Yes, that's right.

MR. THOMPSON: And so -- there is then, as I understand this K1, tab 3, deducted from the revenue requirement, a mitigation amount, which you show on line 2 of this K1, tab 3 of 137.9 for nuclear, and there's another amount on another exhibit for hydro. And those -- the total of them, as I understand, to be $228-million.

And that, I understand, are tax-loss calculations. Have I got that straight? It's bringing tax losses into

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account to eliminate taxes in their entirety in the test period.

MR. BARRETT: It actually goes beyond that. And maybe I'll ask Mr. Heard just to speak to tax loss mitigation.

MR. HEARD: Sure. The -- in terms of the income taxes or the payments in lieu of income taxes for us, really comes out that there aren't any during this period. So what this does is -- because we're utilizing these tax losses, but we're going beyond utilizing the tax losses, to the extent that we're actually applying the benefit of the remaining tax losses that aren't used during this period, during this test period.

MR. BARRETT: I think I referred earlier, Mr. Thompson, to an accelerated give-back of the tax losses, and that's what, for example, at K1, tab 3, Schedule 1, line 2 represents. So it goes beyond taking taxes payable to zero and reduces the revenue requirement further by this amount.

MR. THOMPSON: Okay. So just in terms of trying to understand that, does that mean you have taken all of the tax losses into account in this test period?

MR. BARRETT: That's correct.

MR. THOMPSON: All right. And in terms of presentation, then, in my simple mind, when taxes were calculated in the normal cost of service presentation, if they were zero, they went in at zero. But here you presented a revenue requirement that includes taxes, and then you are taking all of those taxes out, and then some, as I understand it. Have I got that straight?

MR. BARRETT: No, that's not correct. The revenue requirement as presented in the filing includes zero taxes payable during the test period. Beyond taking taxes to zero, we have through this mitigation proposal accelerated return of the leftover tax losses, so the revenue requirement presentations take taxes payable to zero.

MR. THOMPSON: So is line 1, 5.153 million, that has taxes at zero?

MR. BARRETT: Yes, that's correct.

MR. THOMPSON: And so that the line 2 is then, in effect, the accelerated piece.

MR. BARRETT: That's correct.

MR. THOMPSON: That's being deducted. Okay. And so looking down the road, when your next application comes in, there are going to be some big numbers in there for taxes. Am I right?

Is this presentation masking reality, is really what I'm asking.

MR. HEARD: What would happen down the road is that when we had taxes payable, the tax losses would have already been used up, and there wouldn't be tax losses to reduce the taxes to zero. However, in these two years anyway, the tax losses were still zero. Or, sorry, the tax was still zero. We were going beyond that and giving back the benefit of the tax losses early, rather than waiting to apply them against future taxes.

MR. THOMPSON: Okay. Let's move on.

Hearing – Day 1
May 22

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standards. That's because the facilities themselves are large and complex and provide almost half of Ontario's electricity needs. Those employed either directly or indirectly in the operations of the prescribed assets number in excess of 9,000 souls, and these facilities, as you know, produce in excess of 68 terawatt hours of hydro -- of electricity per year.

The continued and reliable operation of these facilities which are crucial to Ontario's electricity needs requires an appropriate level of maintenance and investment. Without the funds necessary to conduct required maintenance and investment in these facilities, OPG will not be able to maintain the value and utility of these assets and the reliability of the electricity system will be at risk.

Now, summary of the revenue requirement is at pages 5 and 6 of the brief. This comes from A1-3, tables 1 and 2. You will see at line, dealing with rate base at line 4; from page five this is hydro, the hydro rate base is roughly 3.9 billion. Nuclear rate base on the next page; roughly 3.5 billion for a combined rate base total of 7.4 billion from line 4.

Expenses for hydro total some -- on line 17, total some 762 million over the test period -- I am talking now the 21 months of course, not per year -- 4.9 billion for nuclear, that's from page 6, for a combined total of 5.7 billion in expenses.

The full revenue requirement for the entire 21-month test period is 1.3 billion for hydro and five.1 billion for nuclear for a combined revenue requirement -- before mitigation, this is, of course -- of 6.4 billion.

I say before mitigation, because OPG has tax loss carry-forwards available from past periods of operation, which it proposes to use to eliminate all tax obligations attributable to the regulated portion of the business during the test period.

OPG's regulated payment amounts for hydroelectric and nuclear production were frozen for three years by government regulation, while the regulated rates were based on a forecast of costs for the three years 2005 to 2008. The rates were averaged to produce one consistent fixed amount for each technology for the entire three-year period. I point this out to note that the deficiency caused by the forecast revenue requirement for the test period has to be measured or has to be looked at as relative not to OPG's actual costs of operation for 2007, but to three-year average forecast 2005 to 2007 costs, which, of course, in their own time was based on an estimate of costs originally done in 2004.

The revenue deficiency relative to that average fixed payment amount for 2005-2007 is -- that existed in 2005-2007 is shown by technology at page seven of this bundle, taken from A1.3.1, table 3. The deficiency in the hydroelectric business is 244.6 million, and the deficiency in the nuclear business is 784.6 million, for a combined total of 1 billion, 29 million, point 2.

Hearing – Day 9
June 10

MR. THOMPSON: So there is no tax in 2008. You've still got losses carry forward, which wipes out the income in 2009 of $324 million; is that right?

MR. HEARD: Yes, that's correct.

MR. THOMPSON: Then there is still something left over that is used for the mitigation amount in the -- that's the subject matter of another panel. Is that right?

MR. HEARD: Yes. And the loss continuity is shown on table 9 of that exhibit.

MR. THOMPSON: But my question is this: Is it implicit in -- and so with the way you are presenting this in this case, in terms of the payment amount, all of the tax losses are being used up, and it's zero taxes, payments in lieu of taxes for 2008 and 2009. Then the mitigation amount is being brought into account in the test period.

Am I right?

MR. HEARD: Yes. That's correct.

MR. THOMPSON: But if there were no tax losses, am I right that the revenue requirement in 2008 and 2009 would be higher by the amount of taxes attributable to the 163 million and the $324 million shown at line 23, for 2008 and 2009?

MR. HEARD: Yes, that would increase the revenue requirement, if there was tax.

MR. THOMPSON: If we assume a tax rate of 31 percent, I make that to be about $150 million, give or take. That's for the two years.

MR. HEARD: Yes. It would be a little less than that.

MR. THOMPSON: Okay. And for the 21-month test period, I did 21 over 24 and I got a number around 130 million. It might be a little more, but in that ballpark. Right?

MR. HEARD: I am just going to have a quick check on that -- subject to check, yes.

MR. THOMPSON: Okay. So we get the hundred and, say, 30 million of taxes related to those amounts, with no tax losses. You have to add to that the 128 million of the mitigation amount, which brings the total to something close to 258 million.

MR. RUPERT: Mr. Thompson, was it 128 or 228 million for mitigation, while you were doing your numbers?

MR. THOMPSON: I thought the mitigation now was 128 million.

MR. RUPERT: Well, I mean we'll check it. Just while you were doing your numbers, I thought it was higher, but sorry for interrupting.

MR. THOMPSON: I thought it was 30 percent of the, roughly, of the unused -- well, I've got it somewhere at 128.

Let's assume it is 128, subject to check. Have I got that right, Mr. Penny? Is that number right for the mitigation amount?

MR. HEARD: I think the mitigation amount is bigger, so I would I need to look into that. There's a factor which needs to be applied, because there's a bit of a circular calculation there that happens. Once you reduce

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the revenue requirement, it generates more loss.

MR. RUPERT: Okay, Mr. Thompson, I'm sorry to interrupt you on this point, but just because you are adding numbers, the numbers as I see them on Exhibit K1 are $90 million in respect of regulated hydro, then a further 138 million in respect of nuclear, which together makes it around 228 million for mitigation, I think.

MR. PENNY: I think what Mr. Thompson was focussing on was the tax payable, but the mitigation amount is more, as Mr. Heard said.

MR. RUPERT: I thought he was talking about mitigation.

MR. THOMPSON: In any event, panel, I guess I've got those numbers wrong, but the point I was trying to focus on is this: Is that the total revenue deficiency implicit in this application, if you assume no tax losses, is the 1.03 billion that you set out in the application, plus the payment in lieu of taxes associated with the income in 2008 and 2009, plus the mitigation amount.

In other words, that's the way we should be looking at this thing. It's that size of number. Am I right? If we forget about tax losses.

MR. HEARD: Yes, if there were no tax losses, you're correct. That's what the situation would be.

MR. THOMPSON: And we know there are going to be no tax losses in -- for the years 2010 and following, right?

MR. HEARD: There is none planned.

MR. THOMPSON: Okay. And so implicit in all of these numbers that are before the Board is a rate increase in 2010. If everything just stayed the same, there is a rate increase in 2010 equal to the sum of the mitigation amount and the taxes on the losses; which is a big number, right?

MR. HEARD: There would be -- if everything else was constant -- there would be an increase, absolutely everything else was constant, there would be an increase if there were no tax losses available, but we haven't done that calculation for '10 and '11 to see what the exact amount would be.

MR. THOMPSON: Okay. Let's leave it there.

Now, my last topic is -- and I apologize for running on -- deals with the compensation and benefits subject that you have been talking to others about. F3, tab 4, schedule 1.

The numbers that I wanted to get some clarification on, and they relate to the pension-related costs in the revenue requirement.

These costs are discussed in the financial statements as well. If you could just keep your finger on page 38 of the financials.

In the prefiled evidence, F3, tab 4, schedule 1, pages 26 and 27, there is a chart relating to these pension costs.

I wanted to, if I could, just correlate pension costs shown in this chart to, if you go back to the tax calculation at Exhibit F3, tab 2, schedule 1, table 7, at line 17 there's an item for pension plan contributions, and

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otherwise be taxed for unregulated activities.

MR. HEARD: Yes, that's correct. And that's largely because, in the main legal entity that we file a tax return for, it's got regulated and unregulated operations in that entity all in one, not separated out at all.

MR. RUPERT: Right. Right.

MR. HEARD: Therefore, at the end of the day, if there was tax owing, there was tax owing, and it would have been due to the unregulated.

MR. RUPERT: So the impact on your financial statements for those years, 2005, 2006 and 2007 cumulatively, is that the amount you're showing as the tax expense for the corporation is lower than it otherwise would have been, I assume. Right? You have taken all of these losses that have been generated by this business, you used them to offset against income earned by other businesses, and presumably have a lower tax expense reflected in your financial statements.

MR. HEARD: Yes, yes. That's correct.

MR. RUPERT: So if I can put it this way, OPG has already realized the benefit of the losses this division generated.

MR. HEARD: They have, yes.

MR. RUPERT: Thank you. It's realized it and also booked the income on it, if you will, booked the lower expense?

MR. HEARD: Yes.

MR. RUPERT: So having done that -- and those losses, of course, related to periods prior to the test period. The losses arose then. They were used on tax returns then. And they were booked in income statements then. I am trying to figure out how they get used by this division going forward.

Let me just pose the question this way. Let's say in 2008, your business plan -- and we accept your filing, accept your application, your numbers come out precisely as projected and you do have a calculation saying this division next year has taxable income of 163 million dollars. Right? Let's also say the unregulated part of OPG makes a lot of money as well. So the corporation has quite a large tax bill now, and puts it all together.

Let's just say in addition to the $50 million of tax that I think we just said was roughly what you would pay on that 163 million of taxable income, let's say the rest of the business had $100 million worth of tax to pay. So the corporation had to cut a check for $150 million, right?

MR. HEARD: That's right.

MR. RUPERT: Now, who is going to pay the $150 million next year? Is it going to be this division, or the other division?

MR. HEARD: The other division.

MR. RUPERT: So, in effect, it is sort of a delayed payment for the loss carry-forwards. They used them last year and they will, in effect, pay you for them in the future as, in fact, the plan unfolds. Right? Is that what I'm getting? Because the whole corporation has to pay $150 million. If they pay the $150 million in total, they're paying $50 million more than their taxable -- tax return for that division would indicate.

MR. HEARD: Sorry, than the unregulated division, that's what you're saying?

MR. RUPERT: No, in the unregulated division, yes. They only have a tax bill of 100, but they're paying 150 now, because they're paying your tax bill as well, if I can put it --

MR. HEARD: Right, yes, so there will have been no recovery of that 50 million because it's already been reflected.

MR. RUPERT: Yes. Well, what I am trying to get at is if you were to stop the clock at the end of 2007 and say: Let's do up full balance sheets of these two divisions, would there not be some inter-company, interdivisional account to say that the unregulated division owes a bunch of money to the regulated division, because it has used up all of those losses already in its tax return. It has sheltered all of its income.

So what I am trying to understand here, is this treatment the normal conventional treatment one would expect? Or are, in fact, we are doing something different than one might otherwise see for stand-alone tax provisions of a regulated and unregulated division?

I am trying to figure out how this benefits flows into 2008 and 2009, since it seems to be a past transaction.

MR. HEARD: I think this is, this would be consistent.

It is not, granted, it is not normal that a regulated entity has tax losses carry-forwards, especially to this extent. But the treatment is normal, in the sense that it has been done on a stand-alone basis.

So regardless of the fact that the unregulated business has had income for tax purpose that has basically absorbed these losses, we are treating it as if that never happened, for purposes of the rate submission.

MR. RUPERT: Let's flip things around, though. Let's say that in these periods the regulated division had been very profitable. Unregulated division had been making losses, such that at the end, there was no tax payable by OPG, because all of the income made by the regulated division was offset by losses on the unregulated division.

Would the regulated division, say, not have to pay something to that other division in that respect?

I mean, you can't sort of say: No corporate tax, therefore this tax provision on my earnings goes away. It seems to me what you have done on the losses is exactly that. You have eliminated any bookkeeping on an amount because it's a loss, but if it were income in this division, presumably you wouldn't say this division had no taxes to pay last year even if it's usually profitable.

That wouldn't be consistent with stand-alone treatment, would it?

MR. HEARD: I am not sure I totally understand the question. But my thought on it is that if we had a situation where the regulated company -- business was taxable, and the unregulated business had a loss in it, it would be difficult to apply the losses to the regulated business, in the sense that, then, some of the principles of rate regulation would be difficult to carry out to make sure that the current ratepayers were paying for or receiving the benefit of tax expense or taxable income in the year it related to it.

So for example, if the regulated business had used the tax losses of the unregulated business, then the regulated business would, in effect, hold back tax value of losses to the unregulated business --

MR. RUPERT: My understanding of how that situation works -- we have had a number of those at the OEB, is my understanding -- is when a regulated company is making money and unregulated affiliates are losing money such that the corporation as a whole is paying no tax, that the regulated company, quite naturally, says: We need to include in our revenue requirement a full slug of tax, even though the corporation is not paying it, because that's a true, a true application of the stand-alone principle.

MR. HEARD: Right, and I would agree with that.

MR. RUPERT: I am trying to understand why in 2005, 2006 and 2007 a true application of the stand-alone principle for your company wouldn't have been for the regulated division to book a tax recovery in those periods, because it was, in fact, realizing the benefit of the losses, not through applying it on tax returns but by giving it to the unregulated division. I am trying to see

the symmetry in what you're doing, and I don't see it.
I see you have one thing for losses and do a different thing for income. So -- I am also mindful of the time here.
MR. HEARD: I understand what you're saying. That was due in the interim rate period, though. There was no recovery of tax, taxes, included in the recovery of losses, included in the interim rates, like as a reduction to the interim rates.
MR. RUPERT: Sure, but the interim rates also didn't assume you are going to lose money on the business either. So I would have thought -- I am trying to struggle with the costs or benefits of tax positions, tracking the actual recording of the loss or income itself.
It seems to me that there has been a real separation in what you're proposing between when the losses were actually recorded by the business, 2005, 2006, 2007, when the losses were utilized by the business, 2005, 2006 and 2007, and when you are proposing to actually want to reflect it in rates. That's the part I am struggling with.
MR. HEARD: If I am understanding what you're saying, the normal principle would be that the benefit of any losses are affected in a reduction in rates, almost in the year in which the loss relates to.
MR. RUPERT: I am not being argumentative. I may come back to Mr. Halperin later. I guess two quick things, and then we will wrap up. One is it seems to me you can realize these losses through several ways. One is applying

them on a tax return in the year in which you have income, one is carrying back them back to apply to a tax return within the loss, and one of them is giving them to somebody else to use them, your unregulated division. They have been realized, in any event.

You seem to be distinguishing the realization of the benefit by virtue of the regulated division -- unregulated division having profits as different from if you had actually put them on a tax return last year, carried them back, for example, if you could, and realized them then.

If you had carried the losses back last year and realized them, if you were able to do that, would you still be proposing this treatment here?

MR. HEARD: Yes, I think we would, because for regulatory purposes, we had thought that the fair thing to do was, if the loss was generated during that interim period, '5, '6 or '7, to make sure that we're effectively providing it back to the benefit of the ratepayer.

MR. RUPERT: Let me leave it there. I know we are pressed for time. Maybe what I'd like to do is I know Mr. Barrett and Mr. Halperin are here for the mitigation panel.

What I am struggling with here is I am trying to figure out whether this treatment here is a faithful application, plain vanilla application of stand-alone principle, or whether it is another form of mitigation. Maybe we can pick it up with this panel at the end, and say the question would be for this last panel: Is the mitigation amount 228 million, or - and I think this is where Mr. Thompson was getting today - is the mitigation amount a large amount, i.e., the amount of loss carry forward shown here, is that really, in fact, a form of mitigation as opposed to a standard accounting treatment?

MR. HEARD: That would be, for example, if my interpretation of what you're saying is correct, that if -- that would be on the assumption that the interim rates included the benefit of these losses in that year? So the 2005, 2006 and 2007 would be assumed?

MR. RUPERT: No, I don't think so. If you made a lot of money in the last three years -- let's say you made a lot of money, a lot more money than was ever thought possible with the 5 percent ROE they gave you, and so on, so your tax bill is bigger. I don't believe you would be coming forward to us, to this Panel, and saying, Our tax bill was bigger for those three years and, therefore, customers in 2008 and 2009 should pay for it.

I don't think you would be taking that position.

MR. HEARD: Right.

MR. RUPERT: So to flip it around, symmetry, if you're losing a lot more money than you ever thought, why should the benefit of those losses be brought forward if you already realized the benefit of the losses in those periods?

Anyway, I will leave it there, but I do think I would like, if we can, to get back into this thing as a package in the mitigation panel, both the mitigation itself and this tax thing. Is that feasible?

MR. PENNY: Yes.

MR. RUPERT: I will stop there. Thank you.

MR. KAISER: I just have a few questions, gentlemen, on the Rudden report. That's at F4, tab 1, schedule 1. Mr. Thompson has taken you through it. As I recall your evidence with respect to his questions, the report came out in April 30th, 2006 and was based upon the 2006 plan numbers, and then came up with the methodology with respect to that.

As I understand your answers to him, that was the last that Rudden had to do with it. They didn't check the 2006 actuals, the 2007 actuals, the 2008 plan or the 2009 plan. Is that correct?

MR. STAINES: That's correct.

MR. KAISER: On page 4 of that document, and this is at the bottom, the last paragraph, they say:

"Rudden has also recommended several refinements to OPG's methodology, including separating CSA costs between labour and non-labour, analyzing CSA costs in more detail for the purposes of assigning cost drivers and improving the selection of cost drivers. Rudden also recommended improvements to documentation and increasing the scope and frequency of OPG's review process."

And then they said:

"Our recommendations are further discussed at section 4(b)."

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MR. BARRETT: I have.

MR. PENNY: -- on those? Do you adopt that evidence?

MR. BARRETT: I do.

MR. PENNY: Thank you. Now, since this isn't a variance and deferral account matter, but since there is -- it's, I guess, not necessarily obvious what was done to answer Exhibit J8.1, I would ask you, Ms. Ladak, to perhaps, without going through all of the explanations and justifications for various things which are covered extensively in the written answer, but if you would, just focussing on the attachment itself, walk us through what you have done in order to make -- do this calculation?

MS. LADAK: Okay. So the request was to prepare an income statement for our Bruce lease and Bruce assets using generally accepted accounting principles, so we have done that. That is in attachment A to this undertaking that was distributed.

The first line we have is the revenue. This includes the revenue that we earn with respect to the Bruce lease, as well as some revenues related to site services that are provided to Bruce Power, and that information is contained within the evidence in Exhibit G.

Then we have provided expenses related to the Bruce assets, and they're all prepared under generally accounting principles, so you will see here we have included things accretion and earnings on nuclear fixed asset removal costs, which are the normal presentation under generally accepted accounting principles for these items.

We also have interest expense here, which is based on our accounting, interest expense that we record in our financial statements.

Then we have income taxes. I will just point out that with respect to the income tax, we have only included current income tax, and we have tax losses, so we have put a zero in for the income tax line. That is basically the income statement.

Then following that, we have some notes explaining some of the line items in the income statement. Attachment 2, which is the last page of the document --

MR. PENNY: Yes. Can you first put the attachment 2 in context, and then explain what you have done there?

MS. LADAK: Yes. So in attachment 2, we have taken the net income that we have calculated under generally accepted accounting principles and we reconciled it to the information that we have in our evidence.

So in Exhibit K, we showed a figure, which is the Bruce net income, in our payment amounts evidence, and that's the bottom line number here. So we have shown the adjustments we would have to make to -- for example, in 2007, to the $143 million in the accounting basis to get to the amount that we have included in our evidence.

MR. PENNY: All right. So you have done the Bruce lease on this income statement basis in attachment 1, and then essentially reconciled it back to the prefiled evidence in attachment 2?

MS. LADAK: Yes, exactly.

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say.

That tax, you're saying that the ratepayers should pay, right?

MS. LADAK: I think it is more related to when the assessment is done, the type of finding that they have.

For example, if they change the CCA class that a particular asset would go into, or change the deductibility of an expense, and it relates to - they're assessing, say, 2000, but that same treatment was adopted in 2005. That's more the type of thing that we're talking about.

MR. SHEPHERD: So that is why I am trying to drill down, because as I understood your evidence, what you were saying is: Whatever the impacts are of an assessment, any previous assessment, whatever the impacts are after April 1st, 2005, the ratepayers bear it.

I didn't see any qualifications to that. Isn't that right?

MS. LADAK: I would just like to review the evidence.

MR. SHEPHERD: Well, let me just clarify. So if the impact is a tax bill, if the impact is interest or penalties, if the impact is reduced CCA in subsequent years, reduced loss carry-forwards, any of those impacts, the ratepayers bear it, starting from 2005. Right?

MR. BARRETT: Well, I guess yes and no.

The 2005 through 2007 period is a prior period, so I would say, to the extent that we had extra costs or penalties as in your example for 2005, I don't believe that we would be able to bring those forward, because it's a prior period. I think this is something that Mr. Rupert raised with Mr. Heard at an earlier panel.

So in that period, the 2005 to 2007 period, as you know, we have calculated tax losses for that period and we're bringing them forward. So if this assessment was to reduce those tax losses that we are proposing to bring forward, then we would make an adjustment on that basis.

MR. SHEPHERD: So can this Board understand, then, that the proposed variance account, with respect to past assessments, the only impact would be if the losses available to you in the test period changed?

Only that impact would be reflected in this variance account, and no other?

MR. BARRETT: I think we're almost there. I think the other thing is, as far as I understand it -- and I will ask Ms. Ladak to check whether I have it right or wrong -- if there are things which affect the calculation that we have done for, say, 2008 and 2009, spill-over circumstances or assessments that cause us to readjust our approach for the calculation of '08 and '09, then that will also be a factor in the recount.

MR. SHEPHERD: So if the assessment is this particular category of asset which you have included in class 8 should be in class 2, and therefore your depreciation is lower, your CCA is lower, then you would want to be able to apply that to the test period and reflect the impact of that in the variance account?

MR. BARRETT: Yes, that's correct.

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MS. LADAK: That's correct.

MR. SHEPHERD: Okay. But if you get a bill from the tax department that relates to a period prior to the first order, you are not anticipating that any portion of that bill would be paid by the ratepayers?

MR. BARRETT: Other than if it caused a recalculation of the tax losses that we were bringing forward from the '05 to '07 period.

MR. SHEPHERD: All right. I understand.

Now, related to that is, you have said also if there is changes to the tax rules or the tax -- your tax rates, I assume you're referring to legislated changes, or regulatory changes -- that you want a variance account for that, too, which would be similar to the type of Z-factor that is sometimes used in IRM mechanisms. Right?

MS. LADAK: That would be included in the variance account. I am not familiar with the Z-factor.

MR. SHEPHERD: Well, what you're saying is your corporate tax rate goes down next year, right? If that has a dollar effect, which it probably won't because you have losses, but if it does, then that is reflected in the account.

MS. LADAK: Yes, that's correct.

MR. SHEPHERD: Okay. So I take it, then, that in your filing, you haven't reflected the expected changes in either tax rates, for example, the capital tax rates, or the CCA rates? You haven't reflected those yet. The expected changes, not the ones that have been legislated

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cetera, has a revenue impact.

Could you explain how that would work, what it is that you are envisioning falls within that particular bucket, so to speak?

MS. LADAK: When "we" do a forecast to determine our revenue requirement for a particular period, it would be based on the existing information at that point in time, in terms of the existing regulations and so on.

If a new -- if there is a court case, as we said here on line 29, if there is a court decision or a new policy that's put forth by Canada Revenue Agency, that would impact the income tax expense that we would have to pay and that would be the type of item that we would record in this account.

MS. CAMPBELL: Now, cited in your evidence as almost a precedent for this type of account is account 1592, which I handed out.

You will agree one of the differences between 1592 and what you are proposing is that account 1592, at least number 3, the differences to be recorded regarding PILs are for a single-year period.

MS. LADAK: That is the difference, correct.

MS. CAMPBELL: Right. And yours is open-ended, is it not?

MS. LADAK: That's correct.

MS. CAMPBELL: And there was a discussion yesterday concerning what's going to be captured by this account as the result of an assessment -- a reassessment, rather.

My recollection is that if there is tax payable, I believe, Mr. Barrett, you said that was OPG's problem?

MR. BARRETT: In the prior period, that's --

MS. CAMPBELL: In the prior period. I apologize. I am thinking about the 1999 reassessment.

MR. BARRETT: Yes. In the prior period, to the extent there were additional costs, we would not be seeking to bring those costs forward into the test period.

However, as I think I indicated yesterday, to the extent that a reassessment caused a recalculation of the tax losses that accrue during the interim period that we are proposing to bring forward, that there would be an effect.

MS. CAMPBELL: What about if there's a reassessment that changes the value of an asset?

MS. LADAK: Well, that would be the same type of thing. If it affects -- we would not touch the tax losses. Any changes that would happen as a result of a reassessment, if the value of an asset changes, the CCA that we would claim on that asset would change for each of the subsequent years.

So the only portion that would go into the variance account would be the portion related to 2005 and future periods, since we have been rate-regulated. The only reason we are proposing to bring those amounts forward is because we are giving up tax losses from 2005 to 2007, and that would have an impact on the tax losses that we are bringing forward.

MS. CAMPBELL: So what we're talking about are periods that occur before you are regulated. I take it the thinking is, is if we're using tax losses that occur prior to regulation --

MS. LADAK: No, we are not using -- no. I've just --

MS. CAMPBELL: I'm failing to understand -- and perhaps it's I haven't had enough caffeine or sleep -- but what I am not understanding is why impacts from 1999, I am having trouble understanding how things that occurred prior to regulation end up being captured in a variance account that is created after you become regulated, and affect the ratepayers going forward.

I am just not understanding that. Could you explain that?

MS. LADAK: We're talking sort of about a policy type of change, so a policy change. We would have prepared our -- we prepared our tax loss calculation for 2005 to 2007 based on certain assumptions and the rules that were prevailing at the time.

If we receive an assessment for that period, even if the assessment relates to 1999, that same policy or rule would apply to future years. So it's not as if we're bringing something forward from 1999. It is just that policy would continue to operate for all future years.

MS. CAMPBELL: That was helpful. Thank you.

I had touched briefly on 1592. One other thing that I note when I look at it is, it is not as expansive as what you are seeking. Would you agree with me?

MR. KAISER: Please be seated.

QUESTIONS FROM THE BOARD:

MR. RUPERT: Panel, I have questions on, I guess, five areas, and those are the answer to undertaking J8.1, which you provided yesterday, a bunch of questions around the decommissioning liability deferral account. Some are Bruce issues and some are not; a few questions on this parts amortization, which I still don't get but I am sure you will set me straight.

Mr. Penny, recall back -- and I think it was on day 10 with Mr. Heard -- we were talking about income taxes, and you said to bring this forward to the payments panel, which deals with mitigation. But inasmuch as Ms. Ladak is here for this morning, at least, I thought I might try some of these questions with this panel, if that's okay.

MR. PENNY: Absolutely.

MR. RUPERT: The segregated mode of operation -- I know some of them are for Mr. Lacivita -- but Exhibit J4.5, which is an accounting statement of the revenues, was filed after he was here. I thought, again, while Ms. Ladak was here, I could ask a few questions on that and save the rest for the afternoon.

On undertaking J8.1, I first wanted to clarify a couple of pieces of information. Attachment 1, which is on page 3, is the GAAP income statement for the three years from Bruce, the Bruce assets and the Bruce lease and so on.

I don't know why I was cross-referencing numbers, but I wanted to ask, under the expenses, accretion on fixed asset removal and nuclear waste management liabilities, the number that shows in 2008 of 255.9 million doesn't seem to be the same number as was used in another undertaking response, which was J1.5. I don't know if you have that handy, or not.

MS. LADAK: Yes. The reason for the difference is the numbers that are in this income statement reflect the fact that some of the accretion was deferred in the nuclear liabilities deferral account.

So in terms of the income statement, when we use -- put in the -- defer a portion of deemed interest and return on rate base as part of the nuclear liabilities deferral account, in the financial statements, that amount is offset against accretion expense.

MR. RUPERT: Okay. So it is 268 million for 2008 in that Exhibit J1.5, and that explains why it is only 255 million in --

MS. LADAK: The difference is the portion that went into the deferral account.

MR. RUPERT: Okay, thanks.

You also note in the text in this response about income taxes, that if the Board were in fact to take a different view than the company's proposed on loss carry-forwards, then you would obviously want to have an income tax line on attachment 1, right?

MS. LADAK: Yes.

MR. RUPERT: It would be a full GAAP tax line, not just taxes payable accounting that is used for regulation rates on a straight-line basis.

MR. RUPERT: Right.

MS. LADAK: The amount of actual amortization that we're recording is based on a rate rider concept, where we look at what we have recovered through rates.

MR. RUPERT: But there is lots of expenses that are included in any kind of a regulatory decision that are going to be different in the actual period than they were in the application.

Why is this one, one that you feel you should get special treatment for?

MR. BARRETT: We go back to the wording in the regulation, which says that the Board shall ensure that we recover the actual amount in the account. So to the extent that we didn't use this approach, we would either be over-recovering or under-recovering the actual parts amount, where we had production variances.

MR. RUPERT: Okay. I think I understand what you have done now. That's helpful.

Taxes, and I appreciate this probably wasn't on your agenda, but let me ask a few of these.

I think you were probably aware, back when Mr. Heard and others were here, these questions about the loss carry-forwards and treatment of those in your application.

MS. LADAK: Yes.

MR. RUPERT: I think at the time, he confirmed a couple of things. One, that the -- at the end of 2007, OPG, the corporation, did not have any loss carry-forwards available for tax purposes, for PILs purposes.

MS. LADAK: That's correct.

MR. RUPERT: That is the losses, the tax losses that were generated by the prescribed assets in this period have all been used to shelter tax on income from the non-prescribed assets.

MS. LADAK: That's correct.

MR. RUPERT: He also indicated that the benefit of that loss carry-forward, if you will -- i.e. the reduction of taxes that occurred as a result of the losses of the prescribed assets -- has been reflected in a lower income tax expense in OPG's financial statements up to the end of '07.

MS. LADAK: Yes.

MR. RUPERT: And that the -- and that, therefore, or the basis for that was that by using the losses to shelter income tax on non-prescribed asset earnings, the losses have, in fact, been realized.

There is no other way the losses will be realized. They don't exist for tax purposes any more. So they can't be realized in the future, because they don't exist in a real -- the only real realization has occurred by virtue of applying them against the earnings from the non-prescribed business. Those are the three things that we discussed.

MS. LADAK: In terms of actual taxes paid, yes, but we're discussing regulatory taxes.

MR. RUPERT: I don't want to get to that. So your view, as he expressed it, of how the stand-alone principle for income tax works when there is unregulated affiliates or divisions and regulated divisions, and losses in one or other of the divisions, his view was that you have applied the stand-alone principle for taxes and that is the way it would always be applied.

MR. BARRETT: Yes, that's correct.

MR. RUPERT: Do you have, could you tell me the sort of the analysis and review of precedents, review of regulatory decisions, review of regulatory accounting texts that you undertook to reach that conclusion?

MR. BARRETT: We certainly have done research on the stand-alone principle.

I don't think you will find a lot of precedents for utilities having large tax losses. It's a very unusual circumstance.

MR. RUPERT: There are precedents the other way, as you are aware, where the unregulated affiliate has large losses and the regulated company has income.

MR. BARRETT: I am generally aware of that.

We consider that what we have done is entirely consistent with the stand-alone principle from the following perspective: We have essentially just looked at the regulated assets and calculated our regulated taxes, without reference to the unregulated part of the company.

And that analysis over the 2005 to 2007 period results in tax losses. As you pointed out, as an actual matter of fact, those tax losses were used, but for purposes of our regulatory approach, we're saying they are not used and they're available to ratepayers, and we have brought them forward to return to ratepayers.

MR. RUPERT: My understanding of this may be defective I'm sure, but one of the principles underlying the stand-alone principle on taxes is this notion of -- to put it simply -- benefits follow costs.

That is often applied in a case where there is a deduction or something in an unregulated business and the view is they should get the tax benefit of that loss, not the ratepayers, because the unregulated business has borne the cost, and therefore should get the tax benefit.

Equally, when it comes to the costs -- and carving it up not but between affiliate and unaffiliated, or regulated and unregulated, but between time periods -- the costs that gave rise to, if you will, the bad results, if I can put it that way, of the regulated division during this period that gave rise to tax losses, that was recorded and booked in '05, '06, '07, right?

You haven't carried forward any of the -- the shareholder bore the brunt. If you had a nuclear unit that went down in that period and resulted in production lower than you first thought when you set your rates, that became OPG's shareholder's problem, right?

MR. BARRETT: To the extent that actual production was less than forecast production, yes, that would be a shareholder hit. But just to return to the question of why there were tax losses, as I understand it -- and Ms. Ladak can provide additional details -- it wasn't a function of having poor production during that period. It was largely a function of us making contributions to the segregated funds, which were deductible for tax purposes. That's what gives rise to the lion's share of the tax losses which we're bringing forward.

MR. RUPERT: Although your nuclear division at a loss of 84 million, you reported last year.

MR. BARRETT: That's --

MS. LADAK: Yes, but when you look total tax losses, like really the lion's share is as a result of this.

MR. BARRETT: Of the contributions to the --

MS. LADAK: Of the contributions.

MR. BARRETT: -- segregated funds.

MR. RUPERT: When you did your analysis and research on this, did you also consult OEB documents on this topic?

MR. BARRETT: We certainly looked for OEB precedents related to the stand-alone principle. Again, I don't think we found too many precedents of circumstances where utilities had tax losses.

MR. RUPERT: So one of the things that is talked about, I believe, in some the earlier documents on LDCs is a question of the point you have just made, trying to discern to what extent is a tax loss a function of the business and to what extent -- and, therefore, benefits result -- belong to the shareholder, and to what extent is it a result of other factors where tax returns are prepared where it might require you to look at whether the shareholder -- ratepayers, excuse me, should see some of that.

Did you look at any of that material at all in your analysis?

MR. BARRETT: We certainly reflected on where the benefit of these tax losses should ultimately go.

To be perfectly candid, there is an argument that could be made that since these tax losses arose prior to April 1, 2008, that OPG should retain all of the benefits associated with those tax losses and not return them to ratepayers.

But, in the end, we decided that that wasn't appropriate.

MR. RUPERT: That's what I was trying to get to at the end, was whether your view was that this was a required treatment by normal generally accepted regulatory principles for taxes or whether it was something that you felt was permitted and it was at your discretion. I guess you just answered that now by saying you felt you might have made an argument to retain it all or put it in 2007.

MR. BARRETT: Yes. We do not believe this treatment is required, but we do believe it is appropriate.

MR. RUPERT: Okay. The last question on taxes I wanted to ask is -- not that your financial statements are determinative of this, but I am -- I couldn't see anywhere in your financial statements in 2007 that OPG had set up a deferral account with a big credit balance in it, in respect of the tax benefit, on the basis that OPG would not want to book that benefit in 2007 statements, because it was taking the position that in fact that benefit was for the benefit of -- that tax benefit was for the account of future regulated ratepayers in 2008 and 2009.

I am just wondering, is there any inconsistency, in your view, there between booking all of the benefit in your financial statements in 2005, 2006 and 2007 and not having a deferral account to recognize your intention to carry it forward for ratepayers?

MS. LADAK: When we recorded the benefits of those tax losses in those periods, we hadn't had a determination that we would be returning these losses or giving up these taxes losses.

MR. RUPERT: Well, sorry, but you filed this application when?

MR. BARRETT: In November of 2007.

MR. RUPERT: Your audited financial statements for 2007 were issued --

MS. LADAK: Well, in addition, we didn't know what the outcome of the hearing would be, so that was the rationale.

MR. RUPERT: Okay. Lastly -- we will make it by noon. On standard mode of operations, Exhibit J4.5 is the one I wanted to ask about. I just want to ask about how the numbers come together and other questions about the more incentive aspects that I can ask Mr. Lacivita.

This was filed after Mr. Lacivita testified and to come down -- we wanted an analysis that came down to the bottom line, row 6, that ties into your application.

I just want to walk through a couple of the lines to

Thank you. Those are my questions.

MR. KAISER: Thank you.

Ms. Campbell.

CROSS-EXAMINATION BY MS. CAMPBELL:

MS. CAMPBELL: Thank you. I would like to ask you three questions on carry-forward, loss carry-forwards.

The first question is, am I correct that what is in the PILs application reflects OPG's interpretation of the stand-alone principle?

MR. BARRETT: Yes, that's correct.

MS. CAMPBELL: All right. And can you tell me, under the way that you have applied that stand-alone principle, would there be any cross-subsidizing between the regulated and non-regulated entities?

MR. BARRETT: No.

MS. CAMPBELL: Why not?

MR. BARRETT: Because we have calculated the taxes just solely looking at the regulated assets and not -- without any reference to the unregulated part of the company.

MS. CAMPBELL: Can you explain to me why OPG characterizes the use of the loss carry-forwards as mitigation?

MR. BARRETT: I guess there are two aspects to that. One, as I think I indicated earlier, I think an argument could be made that the tax losses which arise during the 2007 -- sorry, 2005 to -- April 1, 2008 period, the so-called interim period, accrue to the benefit of OPG.

They're a prior period benefit.

We have decided that it was appropriate to bring them forward, and on that basis we have described them as a form of mitigation.

As well, part of our proposal is to accelerate the give-back, so that all of the available tax losses are given back over the test period, rather than giving those tax losses back over a more extended period.

MS. CAMPBELL: Thank you. Now, I would just like to ask you a quick question about the proposed design of the nuclear payment amounts.

There's a reference on page 2 of the evidence to the fact that:

> "Generators in Ontario and other jurisdictions recover fixed costs."

MR. RUPERT: Which part of the evidence is this, Ms. Campbell?

MS. CAMPBELL: I'm sorry, Exhibit I1, tab 2, schedule 1, page 2.

MR. RUPERT: Thank you.

MS. CAMPBELL: Line 9.

MR. BARRETT: Sorry, what was the page number again?

MS. CAMPBELL: Page 2.

MR. BARRETT: Yes.

MS. CAMPBELL: Line 9.

MR. BARRETT: Yes.

MS. CAMPBELL: You were talking about the rationale for including a fixed component in the design of the

TAB 5

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UNDERTAKING J8.1

Undertaking

Calculation of the net revenue contribution from the Bruce assets computed on a conventional GAAP basis for 2007, 2008 and 2009.

Response

While OPG does not believe that the use of a conventional GAAP basis is an appropriate methodology for calculating the Bruce "revenue less costs" to use as an offset to the revenue requirement, OPG has prepared an income statement for the Bruce lease and generating stations under GAAP (Attachment 1) in response to an undertaking request. OPG has also provided a reconciliation of the net income under GAAP to the Bruce revenues less costs that are presented in Exhibit K (Attachment 2).

The Bruce station and lease are not one of OPG's business segments for reporting purposes. Therefore, the attached income statement was prepared specifically for this undertaking. OPG does track certain costs associated with the Bruce station for management reporting purposes, and where this information was available, OPG has used it in the attached income statement.

The major differences between OPG's proposal and the attached GAAP-based income statement are:

- the inclusion of a return on rate base as a cost;
- the treatment of asset retirement costs; and
- the revenue recognition policy for lease revenue.

In the income statement approach, OPG has allocated a portion of accretion expense and earnings on nuclear segregated funds to the Bruce stations. In the evidence, OPG used the same treatment for asset retirement costs for the Bruce station as for OPG's other stations. The rationale for this treatment is that O. Reg 53/05 states that OPG shall recover all the costs it incurs with respect to the Bruce Nuclear Generating Stations. Decommissioning the Bruce stations, as well as disposing of used fuel and low and intermediate level waste generated by the Bruce stations are OPG's responsibility under the Bruce Lease Agreement. Further, section 6(2)5 of the regulation requires the Board to accept the fixed asset values related to the Bruce facilities as per the 2007 audited financial statements. These values include the Bruce asset retirement cost.

Section 6(2)10 of the regulation states that if OPG's revenues earned with respect to the Bruce lease exceed the costs OPG incurs with respect to the Bruce stations, the excess shall be applied to reduce the amount of the nuclear payment amounts. OPG financed the Bruce assets through a combination of debt and equity. The cost of debt for the Bruce assets is represented by OPG's interest cost and the cost of equity for the Bruce assets is represented by an opportunity cost. Therefore, OPG has determined interest and equity costs for the Bruce assets, using the same capital structure, deemed interest rate, and rate of return on equity that is applicable to its prescribed assets. OPG continues to own the Bruce assets and bears the risks associated with ownership. The lease payments OPG negotiated with Bruce Power included an assumed return on this investment. Therefore, OPG is entitled to the opportunity cost of its ownership of the Bruce assets.

OPG's interpretation of the regulation is that all of its costs of ownership are costs associated with the Bruce lease. This interpretation of the regulation is supported by the fact that the interim payment amounts approved by the Province include a return on rate base as one of the costs associated with the Bruce lease.

In addition, section 6(2)8 of the regulation requires the Board to ensure that OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan. This liability includes the nuclear liabilities associated with the Bruce facilities. OPG's proposal for recovery of the revenue requirement impact of the nuclear decommissioning liability is supported by the fact that the regulation specifies a return as one of the components of revenue requirement that should be recorded in the nuclear liabilities deferral account. Since section 6(2)7 of the regulation specifically mentions a return as part of the revenue requirement for the nuclear liabilities deferral account, the only reasonable interpretation of section 6(2)8 is that a return on rate base must be included as part of the revenue requirement for OPG's total nuclear liabilities.

Because OPG funds its asset retirement costs for nuclear stations through segregated funds, earnings from these funds are recorded in OPG's income statement based on GAAP. However, inclusion of these earnings as part of the revenue associated with the Bruce generating stations is not appropriate for rate setting purposes because the contributions to these funds were predominately made from investor supplied capital.

OPG's proposal related to the Bruce assets results in a similar treatment for these assets as OPG's prescribed facilities. If this treatment is changed, it would not be appropriate to give rate payers the benefit of the tax losses associated with the Bruce stations. This would result in a significant reduction to the tax losses available for rate mitigation purposes during the test period.

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Attachment 1

BRUCE Net Income for the 12 Months Ending ($Millions)	2007	2008	2009
Total Revenue (note 1)	284.6	290.1	291.3
Expenses			
Fuel (note 2)	16.8	14.1	14.8
Depreciation (note 2)	76.6	69.8	66.7
Property Tax	13.8	15.2	15.5
Capital Tax (note 2)	1.1	4.4	3.6
Other (Income) Loss	0.0		
Accretion on fixed asset removal and nuclear waste management liabilities (note 4)	207.2	255.9	282.0
Earnings on nuclear fixed asset removal and nuclear waste management funds	(194.2)	(234.9)	(262.0)
Interest expense (note 3)	20.3	21.2	21.1
Total Expenses	141.6	145.7	141.7
Income Tax (note 5)	0.0	0.0	0.0
Net income after tax	**143.0**	**144.4**	**149.6**

Notes to the Bruce Income Statement:

1. Revenues include Bruce lease revenues as per Ex. G2-T2-S2 Table 1, and consist of fixed (base) rent, supplemental rent, amortization of prepaid rent, and services. OPG accounts for Bruce lease revenue using the cash basis of accounting. This is consistent with GAAP. Under the cash basis of accounting, OPG recognizes lease income as stipulated in the lease agreement to the extent that the lease payments are expected to be included in future regulated prices charged to customers. As a result of changes to accounting for regulatory operations, OPG will account prospectively for these lease revenues on a straight-line basis beginning January 1, 2009. However, in response to this undertaking, OPG has constructed the Bruce income statement as if the lease revenue was accounted for on a straight line basis, as requested by Mr. Rupert. This results in an additional $21 Million of revenue in the income statement compared to the evidence for 2007 and 2008, and an additional $16 Million in 2009.

   Section 6(2)6 of the regulation states that in making its first order, the Board shall accept the values in OPG's most recently audited financial statements, including the revenue requirement impact of accounting policy decisions. It is OPG's position that the Board shall accept OPG's accounting policy for recognizing Bruce lease revenue.

2. OPG deferred certain costs that are normally expensed by unregulated entities in the nuclear liabilities deferral account for 2007 and the first quarter of 2008. These consist of a portion of depreciation expense, fuel expense, low and intermediate level waste expense, capital tax, and interest. OPG also recorded a return as part of the nuclear liabilities deferral account as prescribed by regulation. The accretion expense in the income statement for 2007 and the first quarter of 2008 is net of the interest and return that were recorded in the nuclear liabilities deferral account. The expenses that are recorded in the nuclear liabilities deferral account are presented in Exhibit G on a gross basis and do not reflect the fact that OPG deferred them. The deferral of these expenses is recognized in Exhibit C for 2007 as part of historic regulatory earnings and in Exhibit K for Q1 2008.

3. Interest that is specifically related to a particular business unit is directly assigned to the business unit. The remaining interest is allocated based on the proportion of each stations' average net book compared to the net book value for OPG's other stations.

4. Accretion expense and earnings on nuclear fixed asset removal and nuclear waste management funds are allocated to each station as specified by the Ontario Nuclear Funds Agreement.

5. Income tax is calculated on earnings before tax as per the Bruce income statement, adjusted for items with different accounting and tax treatment to determine taxable income for Bruce on a standalone basis. OPG's operations

related to the Bruce lease and generating stations result in tax losses. The tax losses arise from tax deductions for OPG's contributions to nuclear segregated funds. It should also be noted that OPG has only considered current tax expense in its determination of tax expense for the Bruce lease and assets, and has not incorporated the impact of future tax expense.

Attachment 2

Reconciliation of Accounting Net Income to Regulatory Net Income in the Filing (Exhibit K)

	2007	2008	2009
Net income after tax per income statement (M$)	143.0	144.4	149.6
Adjustments to net income to calculate Bruce income per payment amounts			
Add: GAAP based expenses in income statement that are not part of regulatory earnings			
Bruce lease accrual	(20.7)	(20.7)	(15.5)
Expenses recorded in nuclear liabilities deferral account	(3.5)	0.0	0.0
Accretion	207.2	255.9	282.0
Segregated fund earnings	(194.2)	(234.9)	(262.0)
Interest	20.3	21.2	21.1
Capital taxes	1.1	4.4	3.6
Deduct: OPG's proposed regulatory costs (as explained in Ex. G)			
Deemed interest	(37.6)	(28.4)	(27.6)
Return On Equity	(27.7)	(70.2)	(66.1)
Deemed capital taxes	(2.8)	(2.6)	(2.5)
Bruce net income as per payment amounts (Exhibit K)	**85.1**	**69.1**	**82.6**

TAB 6

OVERVIEW OF OPG'S REVENUE REQUIREMENT

As a starting point, O. Reg. 53/05 requires the OEB to accept OPG's assets and liabilities as established by OPG's 2007 audited financial statements. Thus, the starting point for determining OPG's rate base for the test period is the fixed asset values from OPG's audited financial statements for 2007, which must be accepted by the Board, together with in-service additions for 2008 and 2009 (Ex. A2-T1-S1, Appendix A, Note 18, page 51; Ex. B1-T1-S1, Chart 1, page 8). The regulated hydroelectric rate base is approximately $3.9B. The nuclear rate base is approximately $3.5B, for a combined rate base total of approximately $7.4B. A summary of the revenue requirement is at Ex. A1-T3-S1, Tables 1 and 2.

The regulated facilities are extremely large and capital intensive, employing complex technologies. They provide almost half of Ontario's electricity needs. The revenue requirement needed to operate these facilities safely and efficiently is correspondingly large. For example, OPG employs, either directly or indirectly, over 9,000 people in the operation of the regulated assets. As a result, a significant portion of OPG's operating costs are labour-related.

The continued and reliable operation of the regulated facilities requires an appropriate level of maintenance and investment. Without the funds necessary to conduct required maintenance and to make required investments in these facilities, OPG will not be able to maintain the value or reliability of these assets.

The revenue requirement for the entire 21 month test period is approximately $1.3B for regulated hydroelectric and $5.1B for nuclear, for a combined revenue requirement, before mitigation, of $6.4B. Unless otherwise specified throughout this argument, however, the 2008 figures presented are annual amounts to enable consistent and transparent year-over-year comparisons. The adjusted 21 month figures for the test period are identified and explained under Issue 10.3 of this argument and in Ex. K1-T1-S1.

OPG has tax loss carry forwards available from the operation of the regulated facilities from 2005 to 2007, the period prior to the OEB assuming jurisdiction over these facilities. OPG has decided that it is appropriate to return these tax losses to ratepayers by applying a portion of them to eliminate all tax obligations attributable to the regulated portion of the business during the test period (Ex. F3-T2-S1, Table 9). OPG has used the remaining tax losses from the prior period as a form of additional rate mitigation to reduce the revenue requirement in the test period by a further $228M.

O. Reg. 53/05 also requires the recovery of certain amounts. These items are largely covered in OPG's argument on deferral and variance accounts (Issues 9.1 through 9.7 below) and include:

- Differences in production due to differences between forecast and actual water conditions, differences in ancillary service revenues, and costs associated with transmission outages (Ex. J1-T1-S1, Sections 3.1 and 4.4);
- The funding of nuclear liabilities (Ex. H1-T1-S3);
- Costs incurred to increase the output of prescribed facilities (Ex. D1-T1-S2; Ex. D2-T1-S3);
- Costs of planning and preparation for new nuclear facilities (Ex. D2-T1-S3);
- Costs incurred with respect to the Bruce Generating Stations (Ex. G2-T2-S1); and
- Costs of the Pickering A return to service project (Ex. J1-T1-S1, Section 4.1).

Offsetting OPG's costs for the test period are revenues from forecast nuclear production (88.2 TWh, Ex. K1-T3-S1, Table 1) and regulated hydroelectric production (31.5 TWh, Ex. K1-T2-S1, Table 1), "other" revenues from the regulated hydroelectric facilities ($57.4M, Ex. K1-T1-S1, Tables 1 and 2) and non-generation revenues from the nuclear facilities ($234.6M, Ex. K1-T1-S1, Tables 1 and 2), as well as revenues resulting from OPG's decision to return to ratepayers a share of the revenues earned in the prior period from Segregated Mode Operations and Water Transactions ($16.2M, Ex. J1-T2-S1, Table 2).

OPG'S REVENUE DEFICIENCY

During 2005 to 2008, the payment amounts fixed by the Regulation were based on an average of a three year forecast, which produced a constant, fixed payment amount for each technology for the entire period.

OPG's revenue deficiency for the 2008 to 2009 test period is, therefore, measured in relation to the three-year average of 2005 to 2007 costs based on a forecast originally done in 2004, not OPG's actual costs of operation for 2007.

The pre-mitigation revenue deficiency relative to that average fixed payment amount for 2005 to 2007 is shown by technology in Ex. A1-T3-S1, Table 3. The deficiency in the regulated hydroelectric business is $241.2M. The deficiency in the nuclear business is $784.6M for a combined total of $1,025.8M, pre-mitigation. The drivers of this deficiency are detailed in Ex. A1-T3-S1, pages 8 to 10 and Ex. L-3-49.

The four most significant contributors to the revenue deficiency are:

(1) OPG's application for a commercial cost-of-capital;

(2) Increases in OPG's cost of providing for nuclear liabilities;

(3) Operating cost increases, the main one of which is labour-related costs including:

  (a) general labour rate escalation

  (b) increases in pension and other post-employment benefits

  (c) the additional cost of providing for new skilled labour in the face of an aging workforce; and

(4) Additional expenditures arising out of a variety of initiatives mandated by OPG's shareholder, including improving the material condition of the nuclear plants and planning and preparation for new nuclear facilities.

COST OF CAPITAL

The Memorandum of Agreement directs OPG to operate as a commercial enterprise with an independent Board of Directors. As an *OBCA* corporation with a commercial mandate, OPG is required to "operate on a financially sustainable basis and maintain the value of its assets" (Ex. A1-T4-S1, Appendix B, page 3).

In accordance with this directive from its shareholder, OPG is seeking a capital structure for the prescribed assets consisting of 57.5 percent equity and 42.5 percent debt and a return on the equity portion of that capital structure of 10.5 percent (Ex. C2-T1-S1). The payments

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adjustments to net fixed assets in its forecast of rate base for the test period. Similarly, OPG has calculated the working capital component of rate base appropriately, including the use of a lead-lag study and forecasts of fuel inventory, materials and supplies.

2. CAPITAL STRUCTURE AND COST OF CAPITAL

OPG has applied for payment amounts based on a deemed capital structure of 57.5 percent equity and 42.5 percent debt. OPG is seeking a return on the equity portion of its capital structure of 10.5 percent. The interim rates were based on a 55/45 debt/equity ratio and a 5 percent return on equity. This capital structure and return are clearly inappropriate for OPG, particularly given its mandate to operate as a commercial enterprise. The capital structure and returns recommended by intervenor cost of capital witnesses are also inadequate and should be rejected because they do not meet any of the three tests of comparable returns, capital attraction or financial integrity.

OPG opposes the use of separate capital structures and rates of return on equity for its two regulated technologies. OPG is seeking the application of a formula to adjust its return in future, so that the OEB does not need to re-assess capital structure and return in every application to set new payment amounts. OPG's cost of debt for the test period is based on both existing issues and forecast issues, the cost of which is based on estimates of future debt costs.

Issue 2.1

What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Issue 2.2

What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated

hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

FAIR RETURN STANDARD

An essential component of the just and reasonable standard, described in the overview section, is the requirement to set rates at a level that permits a utility to earn a fair return on invested capital. Mr. Justice Lamont, of the Supreme Court of Canada, defined a fair return as follows:

> "By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[5]"

The Supreme Court of Canada reaffirmed this definition in 1960.[6] Mr. Justice Locke concluded that "the [return] must be sufficient to enable it to pay reasonable dividends and attract capital...". He also concluded that "the obligation to approve rates which will give a fair and reasonable return is absolute".[7]

The absolute nature of the obligation to apply the fair return standard was also endorsed by the Federal Court of Appeal. In *TransCanada Pipelines Ltd.* v. *National Energy Board,* the Court agreed that the "absolute" nature of the obligation to approve rates that will enable the company to earn a fair return means that the required return must be determined solely on the basis of the company's cost of equity and is not influenced by any resulting rate impact on customers.[8]

The legal requirement to apply the fair return standard has also been recognized by the OEB. In EB-2005-0421 (Toronto Hydro), the OEB noted that "as a matter of law, utilities are entitled to earn a rate-of-return that not only enables them to attract capital on reasonable

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[5] *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186 at 193.
[6] *British Columbia Electric Railway Co. Ltd.* v. *British Columbia (Utilities Commission)*, [1960] S.C.R. 837 at 854.
[7] *Ibid.* ; see also *Union Gas Ltd.* v. *Ontario (Energy Board)* (1983), 1 D.L.R. (4th) 698 at 711 and *Hemlock Valley Electrical Services Ltd.* v. *British Columbia (Utilities Commission)* (1992), 66 B.C.L.R. (2d) 1 (B.C.C.A.).
[8] 2004 FCA at para. 36; see also *Hemlock Valley, supra.*

terms but is comparable to the return granted other utilities with a similar risk profile" (April 12, 2006, pages 32 to 33).

The Supreme Court of the United States has also adopted the fair return standard. Rates that are not sufficient to yield a reasonable return on the value of a utility's property used to provide service are unjust, unreasonable, and confiscatory. The return must correspond to the return to other businesses of similar risk, be sufficient to assure confidence in the financial integrity of the utility and be adequate to support its credit and enable it to raise money for the conduct of its business.[9]

The fair return standard, therefore, must meet three requirements:

1. Comparable returns.
2. Financial integrity.
3. Capital attraction.

THE STAND ALONE PRINCIPLE

Most of the cost of capital witnesses who testified in this proceeding agree that OPG's cost of capital should be determined on a "stand alone" basis. By stand alone, Ms. McShane meant that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the regulated operations if they were raising capital in the public markets on the strength of their own business and financial parameters. The evidence of Mr. Goulding, of London Economics, retained by Board Staff, was that as an *OBCA* corporation, OPG should be treated no differently from any other entity that the OEB regulates and that provincial ownership "should not influence the OEB any more than if OPG was 100 percent owned by a private entity" (Tr. Vol. 12, page 111). Accordingly, Mr. Goulding confirmed that OPG should be viewed on a stand alone basis, disregarding the fact of its ownership by the Province (Ibid., pages 111-112).

Mr. Goulding agreed that provinces which sell power at less than full value lose out twice: first as shareholders because they receive less revenue and lower profits than would

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[9] *Bluefield Water Works &Improvement Company v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679 (1923) at 692; *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) at 603.

otherwise be achieved by their investments; and second, as policy makers, they lose again because under-priced electricity encourages over-consumption and all of its attendant adverse environmental impacts (Tr. Vol. 12, page 143).

Drs. Kryzanowski and Roberts, corporate finance experts retained by Pollution Probe, also took the position that OPG's "risk" should be determined on the stand alone principle, by which they meant setting aside the impact of provincial ownership. Under the stand alone principle, one should assess the appropriate capital structure from the standpoint of an investor-owned utility of comparable risk (Tr. Vol. 13, page 57).

Professor Booth, retained by CCC/VECC, while somewhat ambivalent on this issue, agreed that from a standpoint of corporate finance principles, we should be asking 'what is the appropriate value of the resources controlled by the entity and what is the entities cost of capital, i.e., the opportunity cost of those resources?' In H.R. 15, Professor Booth said that the stand alone approach to the cost of capital should be used to improve resource allocation and that customers should have to pay a price for electricity that reflects the opportunity cost of production. Professor Booth confirmed this evidence and further confirmed that he did not resile from that approach now (Ex. K12.3; Tr. Vol. 2 pages 16-18; Tr. Vol. 13, pages 170-171).

Professor Booth admitted that his views on the impact of the shareholder being the province of Ontario were not founded in principles of corporate finance (his area of expertise) but were matters of regulatory policy (Tr. Vol. 13, page 161). Accordingly, Professor Booth's views on the implications of provincial government ownership in this case are personal in nature and not founded in his area of qualified expertise.

Dr. Schwartz testified that whether or not there were subsidies between ratepayers and taxpayers it was not a principle that informed his opinion in this case (Tr. Vol. 14, page 61).

The stand alone principle is not only supported by logic and the evidence of most of the cost of capital experts. It is also supported by extensive regulatory precedent. Canadian regulators, including the OEB, have a long history of assessing regulated operations, including their risk and cost of capital, irrespective of who their owner, parent or affiliate may be[10].

In H.R. 15, the Report of the Board, page 14/5, the OEB emphasized the necessity of separating ratepayers from taxpayers conceptually and rejected the notion that because "the customers are the shareholders" reducing the required level of net income from what it would otherwise be was justified. The OEB went on to say:

> 14.77 This Board is concerned that Hydro's failure to reflect the cost of equity capital in determining net income may amount to serious cross-subsidizations of all electricity usage (H.R. 15, Report of the Board, page 14/32).

> 14.80 The Board believes that consumers and owner-like equity interest problems can be solved by having Hydro treat consumer interests separately from owner-like interests, and recommends that Hydro treat such interests separately (H.R. 15, Report of the Board, page 14/33).

Subsequently, in H.R. 16, the OEB again considered the issue of the government's debt guarantee for Ontario's Hydro and again expressed concern that Hydro's lower cost of capital may lead over time to non-optimal use of capital and labour resources. The OEB was concerned that a combination of lower capital costs and lower prices may have various ramifications for the economy in Ontario such as excessive use of electricity. At pages 10/9 to 10/10) the OEB said:

> "The Board has concluded that a payment in the form of a fee paid by Hydro to the Ontario Government should be introduced to compensate taxpayers of the Province for the risk they bear by guaranteeing Hydro's debt and for which they are not now appropriately compensated."

Further, although the matter was not explicitly addressed, it necessarily follows from the OEB's decision to award government-owned electric Local Distribution Companies such as

[10] See: *TransCanada Pipelines, (National Energy Board, Reasons for Decision, In the matter of the Application Under Part IV of the National Energy Board Act, (Rates Application of Transcanada Pipelines Limited, August* 1980); *the Public Utilities Board, Alberta, Decision E93060, re:, NOVA Corporation of Alberta*, August 20, 1993.

Toronto Hydro and Hydro One commercially-based capital structures and rates of return that the OEB did not regard government ownership as a material consideration.

TESTIMONY OF KATHLEEN C. MCSHANE

Like all the other cost of capital experts (except Schwartz) in this case, Ms. McShane conducted two analytically distinct analyses. The capital structure (the ratio of debt and equity used to finance the company's rate base) was determined on a deemed basis to reflect the probability that future returns to investors will fall short of their expected and required returns (business risks). The proposed deemed capital structure is also intended to ensure that OPG's regulated business would have has access to the public debt markets on the basis of a stand alone credit ratings in the A category. Ms. McShane's concept of a benchmark return on equity, on the other hand, was used to determine, for a given deemed capital structure, the appropriate cost of, or return on, equity ("ROE"). Ms. McShane relied on the equity risk premium approach to determine ROE, as well as on a discounted cash flow analysis and an analysis of earnings from comparable companies.

RETURN ON EQUITY

The equity risk premium test recognizes that an investor in common equity takes greater risks than an investor in bonds. Accordingly, the equity investor requires a premium above bond yields as compensation for the greater risk. The risk premium test is forward-looking. To develop an appropriate risk premium, data must be analyzed in the context of current and anticipated market conditions which, in turn, requires the exercise of informed judgment.[11] Historical risk premium data, while informative, are not determinative because of the differences in market conditions from one period to the next.

Like Professors Kryzanowski, Roberts and Booth, Ms. McShane began her analysis with a risk-free rate, which, for these purposes, is equal to the forecast long-term Government of Canada bond yield. The forecast involved the use of *Consensus Forecasts* for ten year yields and an adjustment to capture the appropriate spread between the ten year and thirty year Canada bonds. She concluded that long-term Canada bond yields were forecast at 4.5

[11] (Goulding, Tr. Vol. 12, page 104; Kryzanowsky and Roberts, Tr. Vol. 13, page 106; Booth, Tr. Vol. 13, page 151)

The calculation of the asset service fee follows appropriate ratemaking principles. For 2008 and 2009, the cost to the regulated business is the same under the asset service fee treatment as it would be if the associated capital were allocated to the prescribed facility rate base (Ex. J9.2).

Rudden reviewed the methodology for computing the asset service fees and concluded "the assets for which Service Fees are charged are required and used by OPG's generation business units" and that "the methodology for determining the usage of the asset by the generation business units for the purposes of allocating the Service Fee is based on cost causation and consistent with the Centralized Support and Administrative Cost methodology (Ex. F4-T1-S1, page 24).

Issue 5.6

Are the amounts proposed to be included in 2008 and 2009 revenue requirements for other operating cost items appropriate?

Other operating cost includes depreciation expense and taxes as calculated for regulatory purposes. OPG has forecast its other operating costs at $71.4M in 2008 and $71.9M in 2009 for regulated hydroelectric (Ex. F3-T2-S1, Table 1) and $316.2M in 2008 and $338.5M in 2009 for nuclear (Ex. F3-T2-S1, Table 4). The depreciation expense included in the revenue requirement is discussed above under Issue 5.2.

Income and capital taxes are discussed below under Issue 10.1. In summary, OPG calculates its regulatory income tax on a "stand alone" basis for the regulated facilities. Regulatory taxable income is $163.0M in 2008 and $324.0M in 2009 (Ex. F3-T2-S1, pages 11-12). The income tax expense included in the revenue requirement has been reduced to zero for 2008 and 2009 because of the use of tax losses from prior years in the regulated business (Ibid.).

OPG is responsible for both the payment of municipal property taxes and a payment-in-lieu of property tax to the Province. Municipal property taxes are regulated under the Assessment Act, 1990 and are levied on the prescribed nuclear and hydroelectric lands and buildings

J1-T3-S1, page 13). As such, the change in the discount rate and the resulting impact on pension and OPEB costs in any given test period is not within OPG's control (Tr. Vol. 14, pages 115-116).

Establishing this account and clearing balances that exceed the trigger provisions will address the underlying risk of cost recovery and provide rate stability. Ms. McShane estimated that a potential shortfall of 0.5 percent in ROE could result from the absence of this account (Ex. KT1.6). The proposed variance account also reduces forecast risk for OPG and assessment risk for ratepayers associated with material variances in these costs. This will contribute to a rate review process that is less contentious and is fair to both OPG and ratepayers.

Changes in Tax Rates, Rules, and Assessments Variance Account

OPG proposes to establish a Changes in Tax Rates, Rules, and Assessments Variance Account to capture the potential impact on the revenue requirement of changes in tax rates and rules, assessment or administrative policies and interpretation bulletins, court decisions, tax assessments or re-assessments (Ex. J1-T3-S1, pages 14-16).

As noted in the evidence, OPG is currently being audited by the Provincial Tax Auditors for 1999 (Ex. F3-T2-S1, page 12). While OPG has incorporated the results of the 1999 audit in its estimate of tax losses from the 2005 – 2007 period and tax expense for the test period, there is a risk that these estimates could be impacted by audits of the 2000 taxation year and later years. The results of these subsequent audits have the potential to cause a material impact on the tax losses that OPG has forecast and used to reduce income tax expense and mitigate the consumer impact of this application in the test period (Ex. F3-T2-S1; Ex. K).

OPG notes that in December 2005, the OEB authorized the regulated electric distributors to use Account 1592, 2006 Payments in Lieu and Taxes Variances, to capture many of the same tax impacts that it is seeking in its account. OPG forecasts taxes and payments in lieu of taxes (where applicable) for the test period based on the tax rates and laws currently in effect. While the impact of an announced or anticipated tax change is generally known in advance of its effective date, typically the timing and implementation requirements associated with the change are uncertain, making it difficult to define the financial impact. Such a change is beyond OPG's ability to control.

In addition, tax reassessments or appeal settlements can take place when OPG is not before the OEB for a revenue requirement determination. Such processes can have significant impacts on the tax provisions included in the payment amounts in effect at the time. These impacts are also beyond the control of OPG.

10. DETERMINATION OF PAYMENT AMOUNTS

Issue 10.1

Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

OPG has calculated its regulatory income and capital taxes in accordance with applicable regulatory and legislative requirements using the stand alone principle (Ex. F3-T2-S1, pages 7-8; Tr. Vol. 9, page 43). OPG is not seeking to recover any income tax expense in the test period. For the regulated hydroelectric facilities, OPG is seeking to recover capital taxes of $8.7M in each of 2008 and 2009. For the nuclear facilities, OPG is seeking to recover capital taxes of $7.9M and $7.8M in 2008 and 2009, respectively (Ex. F3-T2-S1, Table 4). OPG also pays capital and property taxes on the Bruce facilities that are included in the Bruce Lease costs (Ex. G2-T2-S1, Table 3).

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation ("OEFC") and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation (Ex. F3-T2-S1, page 7).

On April 1, 2005, OPG adopted the taxes payable method for income taxes for its regulated operations because this is the method approved by the OEB for the utilities it regulates. Under the taxes payable method, only the current tax expense is recorded in the financial statements; future taxes are not recorded to the extent that they are recovered or refunded through regulated payment amounts (Ex. F3-T2-S1, pages 7-8).

For the test period, regulatory income taxes are determined by applying the statutory tax rate to regulatory taxable income of the combined nuclear and regulated hydroelectric operations as well as taxable income associated with the Bruce facilities. Regulatory taxable income is computed by making adjustments to the regulatory earnings before tax for items with different accounting and tax treatment. The most significant adjustments are discussed in the evidence (Ex. F3-T2-S1, pages 9-11and Tables 7 and 8).

OPG is subject to the Ontario capital tax. For regulatory purposes, the rate base in excess of the general capital tax deduction is used as a proxy for the taxable capital used for calculating Ontario capital tax. The full capital tax deduction was attributed to regulated operations, consistent with the determination of regulatory income taxes on a stand-alone basis (Ex. F3-T2-S1, Tables 2 and 5).

Issue 10.2

Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

For the years 2005 – 2007, OPG had tax losses in its regulated business (Ex. F3-T2-S1, Tables 7, 8 and 9). The cumulative losses at the end of 2007 that are available to be carried forward are $990.2M. These tax losses were generated mainly due to OPG's contributions to segregated funds, which are deductible for tax purposes. The segregated funds cover all OPG owned nuclear facilities including Bruce (Ex. H1-T1 S1, page 2). OPG made annual contributions of $454M from 2005 to 2007 as well as a one-time additional payment of $334M in 2007 in accordance with the Ontario Nuclear Funds Agreement.

While an argument could be made that these tax losses belong to OPG and not to ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is appropriate that they be returned to ratepayers. Therefore, OPG has applied its total cumulative tax losses at the end of 2007 to reduce the projected regulatory taxable income in 2008 and 2009 of $163.0M and $324.0M, respectively, to nil in accordance with standard regulatory practice. In addition, the remaining projected tax losses are used to mitigate the customer bill impact of OPG's payment amount and deferral/variance account recovery proposals (Ex. K1-T2-S1, Table 1; Ex. K1-T3-S1, Table 1).

As noted in the evidence, OPG is currently being audited by the Provincial Tax Auditors for 1999 (Ex. F3-T2-S1, page 12). While OPG has incorporated the results of this audit in its estimate of tax losses for 2005 – 2007 and in determining tax expense for the test period, OPG remains subject to audit for the years after 1999. As a result, there is a degree of uncertainty as to the final tax losses available to return to ratepayers and the tax expense for the test year. However, OPG proposes that the payment amounts for the test period be set on the basis of currently calculated tax losses as this represents the best information available, and any impact of audits for taxation years after 1999 be addressed through a tax variance account as discussed under Issue 9.7 (Ex. J1-T3-S1, page 14).

Issue 10.3

Are OPG's methods for removing Q1 2008 costs, revenues and production appropriate?

Since the OEB's jurisdiction to set payment amounts did not begin until April 1, 2008, Q1, 2008 costs, revenues and production must be removed from the annual data provided in the application (Ex. K1-T1-S1, page 1). The application uses annual forecasts for 2008 to allow for comparisons of year-over-year trends and to provide information consistent with OPG's business planning process and fiscal year.

The Q1 adjustments are based on an analysis of the trending of forecast information for 2008 (Ex. L-1-123). This analysis took into account matters such as the pattern of outage costs, It is also OPG's submission that the approach used to calculate the amounts in the deferral account should be consistent with the method used to calculate the revenue requirement in interim rates. This is precisely because the intent of this deferral account is to provide OPG with the rates it would have received if the adjustment to the reference plan in 2006 had been known when interim rates were originally established. In other words, the record is clear that had the government approved the new reference plan incorporating increased liabilities associated with the Bruce refurbishment before approving O. Reg. 53/05, those new liabilities would have been embedded in the interim rates in accordance with the "rate base method" adopted for the recovery of those costs.

The CME argument that "nuclear liability costs attributable to Bruce are only recoverable to the extent that Bruce costs exceed Bruce revenues" is just dead wrong. Section 6(2)9 of the Regulations could not be clearer in providing that the OEB is required to ensure that OPG recovers "all the costs it incurs" with respect to the Bruce facilities. It is only when revenues exceed costs, and not the other way around, that any benefit accrues to ratepayers. Sections 6(2)9 and 10 can only be read to mean that any credit to the revenue requirement arising from the Bruce facilities is after recovery of *all costs incurred* with respect to those facilities. The evidence is absolutely clear, and unchallenged, that nuclear waste and decommissioning liabilities related to the Bruce facilities are a cost OPG incurs with respect to those facilities.

The only question remaining, therefore, dealt within Issue 7.1 below, is how to quantify the cost, both for the deferral accounts and the test period. As discussed in OPG's argument-in-chief and under Issue 7.1 below, OPG believes that the Regulation requires use of the rate base method.

It should also be noted that one consequence of excluding Bruce nuclear waste and decommissioning costs associated with the Bruce facilities from the determination of payment amounts, as urged by Board Staff and CME et al, would be a significant reduction in the tax loss carry-forwards that OPG has voluntarily made available to mitigate test period rate impacts. If the costs of nuclear liabilities with respect to the Bruce facilities are excluded from the determination of payment amounts, there would be no logical basis for giving, and

OPG would not give, ratepayers the benefit of tax deductions associated with OPG's segregated fund contributions related to the Bruce facilities. In the 2005 to 2009 period, OPG will have made segregated fund contributions of some $2.5B (Ex. J15.11) of which approximately $1.5B is associated with the Bruce facilities. The withdrawal of these contributions from the "regulatory account" would cause a significant reduction of available accumulated tax losses from 2005 to 2009 (Ex. J8.1, Note 5).

In summary, it is clear that return on equity in respect of the Bruce NGS is a cost incurred by OPG. The argument that nuclear liabilities associated with Bruce NGS are not recoverable as part of the approved reference plan is not sustainable on the plain wording of O. Reg. 53/05. Ratepayers cannot get the benefit of Bruce revenues without taking full account of all associated costs, which includes the cost of OPG's obligations with respect to nuclear liabilities associated with the Bruce facilities. The Regulation, and the surrounding circumstances when the Regulation was passed, make clear that the rate base approach is the correct way to value the cost of these liabilities.

Interestingly, the Hydro One precedent was accepted by CCC, VECC, SEC and AMPCO as part of the settlement agreement in that case (Appendix 2, Settlement Proposal, EB-2006-0501 Decision with Reasons for 2007 and 2008 Electricity Transmission Revenue Requirements for Hydro One Networks Inc., August 16, 2007). None of these parties indicated in their submissions why they would support an arguably broader account for Hydro One and yet oppose one for OPG.

For all the reasons given above, in evidence and in its argument-in-chief, OPG submits that its proposed account is appropriate and should be approved by the OEB.

<u>Changes in Tax Rate, Rules and Reassessments Variance Account</u>

All intervenors that made submissions on this issue either supported the establishment of this account, or were neutral. Some parties would limit the scope of the account as outlined in Account 1592 of the Uniform System of Accounts for Electric Distribution Utilities. CME, VECC, SEC would accept OPG's proposal only "on the same basis as applies to distributors" (SEC argument, para. 247). OPG notes that its proposed account generally accords with the scope of Account 1592, but OPG's proposal also includes a provision to record variances associated with tax reassessments.

VECC wants to ensure that the OEB and intervenors would have an opportunity to explore the circumstances leading to any reassessment-related impacts before there was any clearing of amounts. CME argued that recoverability of reassessments should be considered on a case-by-case basis.

The CCC observed that tax assessment lags create a unique risk for regulated utilities with forward test years (CCC argument, para. 147). CCC also acknowledged that for OPG, an assessment or reassessment of a tax year prior to April 1, 2008 could have implications on both the tax expense forecast for the test years and the amount of tax losses available for mitigation. Despite these acknowledgements, CCC proposes limiting any reassessment to the period after April 1, 2008, when OPG was first subject to rate regulation by the OEB.

CCC's proposal is unfair and unbalanced. OPG is seeking the inclusion of impacts of reassessments for the years prior to regulation by the OEB because it is voluntarily providing the benefits of the calculated tax losses from the 2005 to 2007 period. If there is a reassessment that reduces the actual losses for 2005 to 2007, then OPG would have given ratepayers a benefit that turns out not to have existed (OPG argument-in-chief, page 106; Tr. Vol. 14, pages 197-201; Tr. Vol. 15, page 20). In this circumstance, OPG believes it is entirely appropriate to include reassessments in the tax variance account.

OPG submits that the OEB should accept the matters to be recorded in this account as described by OPG in its argument-in-chief and in Ex J1-T3-S1, pages 14 to 16.

New Variance and Deferral Accounts Proposed by Others

AMPCO proposed two new accounts for OPG: 1) IESO Non-Energy Charges Variance Account to capture differences between forecast and actual charges; and 2) CMSC Account for sharing CMSC revenues on a 50/50 basis (AMPCO argument, paras. 185 and 156). In addition, CCC proposed a new account to capture differences between budgeted and actual expenditures for Regulatory Affairs in conjunction with a reduction in the 2009 budget to 50 percent of the 2008 budget (CCC argument, para. 85).

OPG submits that none of these accounts should be established by the OEB.

With respect to its request for an account to capture variances between forecast and actual IESO non-energy charges, AMPCO provides two grounds. The first is that these charges are difficult to forecast and not subject to the control of management. OPG does not dispute these points. The second is that OPG's forecasting methodology is suspect because it relies on a data set that only goes back to 2005. OPG rejects this criticism and submits that its methodology is sound. OPG's forecast of global adjustment costs is based on a regression analysis that used all of the monthly HOEP and global adjustment charges data available since the inception of the global adjustment mechanism in January 2005 (Ex. L-1-60; http://www.ieso.ca/imoweb/b100/b100_GA.asp). Monthly data back to 2005 is sufficient to produce a reasonable forecast of these charges.

10. DETERMINATION OF PAYMENT AMOUNTS

Issue 10.1

Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

No intervenors objected to OPG's calculation of its regulatory income and capital taxes. As such, and for all the reasons set out in its evidence and argument-in-chief, these amounts should be accepted by the OEB as filed.

Issue 10.2

Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

All of the intervenors who specifically commented on this issue (CCC, CME, and SEC) supported OPG's proposed treatment of the loss carry forwards. PWU also indicated its support for OPG's application as filed, implicitly indicating its support for the proposed treatment.

SEC's submission demonstrates that it does not quite understand OPG's approach (SEC argument, paras. 253-254). OPG is required to file one tax return which includes both the regulated and unregulated segments of its generation business, and losses can only be applied against the taxable income of the entire company. OPG cannot file two separate returns or segregate the losses and pay tax for one segment of the business and carry forward losses for the other segment. For purposes of establishing the payment amounts, OPG retained 100 percent of these losses within its regulated operations in order to eliminate <u>regulatory</u> income taxes from the revenue requirement and to further mitigate the revenue requirement. For regulatory purposes no tax losses were allocated to the unregulated businesses.

Since OPG pays its taxes on a corporate basis, it makes no sense to follow the suggestion by SEC that losses generated by the regulated business not be used to lower overall <u>actual</u>

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corporate taxes. As noted above, this approach has no impact on what ratepayers pay since the losses are notionally preserved within the regulatory operations.

Given that there are no real objections to OPG's proposals, and for all the reasons set out in its evidence and argument-in-chief, the Board should accept OPG's proposed treatment of tax losses as filed.

On a related issue, OPG notes that certain intervenors (CCC, CME, and SEC) object to including within the proposed Tax Variance Account an ability to reflect the impact on the tax losses of post 1999 reassessments. As OPG pointed out in its argument-in-chief, there is uncertainty with respect to the amount of tax losses available from the April 1, 2005 to April 1, 2008 period since the Provincial Tax Auditors have not completed their audits for the post-1999 period. Despite this uncertainty, OPG has proposed to return to ratepayers its best current estimate of the tax losses available – something that intervenors have been happy to accept. It is somewhat disappointing, that these objecting intervenors are prepared to accept the return of tax losses that OPG voluntarily dedicated to mitigating the rate increase without giving the company a reasonable degree of protection against an unexpected tax audit result.

Issue 10.3

Are OPG's methods for removing Q1 2008 costs, revenues and production appropriate?

There were no objections from intervenors with respect to OPG's method for removing Q1 costs, revenues and production. As such, and for all the reasons set out in its evidence and argument-in-chief, these amounts should be accepted by the Board as filed.

11. IMPLEMENTATION OF NEW PAYMENT AMOUNTS

Only AMPCO and SEC made submissions on OPG's proposal for implementing the new payment amounts. AMPCO indicated that it supported OPG's proposal to recover the retrospective amounts back to April 1, 2008 using actual consumption (AMPCO argument, para. 187). SEC proposed that the new payments amounts be effective April 1, 2008 except for that portion related to OPG's increased return on equity (SEC argument, para. 259). SEC made this proposal even though it acknowledges that: 1) OPG moved with reasonable diligence to file its application once the Board issued its Filing Guidelines and 2) that OPG is not responsible for the delay in the establishment of new payment amounts (SEC argument, para. 257). Given these admissions, the Board should reject the SEC proposal. SEC's proposal is patently unfair to OPG and completely inconsistent with the Board's statutory obligation to set just and reasonable payment amounts.

Given the lack of intervenors' objection, and for the reasons set out in its evidence and argument-in-chief, the OEB should accept OPG's proposal for implementing the new payment amounts.

Once the OEB reaches its decision in this matter, OPG proposes that it be provided the opportunity to calculate the test period payment amounts that result from that decision. There are complex interactions among some of the components of the payment amount calculation, for example, the calculation of tax losses during the test period and the associated impact on the payment amounts, and OPG is best positioned to correctly perform these calculations within the parameters set by the OEB. This approach is analogous to that used in rate hearing where the OEB directs the applicant to file a draft rate order reflecting the Board's findings.

TAB 7

EB-2007-0905

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

NOVEMBER 3, 2008

6 BRUCE NUCLEAR STATIONS: OPG's REVENUES AND COSTS

OPG owns the Bruce A and Bruce B nuclear generating stations located on the shore of Lake Huron near Kincardine, Ontario. Currently, six units are operational and the two other units are being refurbished. When all eight units are operational, the aggregate capacity of the stations will be over 6,200 MW.

In 2001, OPG leased the stations to Bruce Power L.P., a partnership not related to OPG.[71] The lease runs until 2018 and Bruce Power has an option to renew the lease for a further 25 years. Bruce Power operates the stations and supplies energy to the IESO-administered electricity market.

OPG receives lease payments from Bruce Power as well as revenues for providing engineering and other services to the partnership. OPG retained responsibility for the decommissioning and nuclear waste management liabilities related to Bruce A and Bruce B.

The Bruce nuclear generating stations are not prescribed generation facilities under O. Reg. 53/05. Bruce Power holds a generation license issued by the Board. The Board, however, has no authority to set or review the terms of the lease between OPG and Bruce Power and it does not regulate the prices for engineering and other services provided to Bruce Power by OPG.

Despite the fact that the Bruce nuclear stations are not prescribed generation facilities, OPG's revenues and costs related to the Bruce lease were major issues in this proceeding.

O. Reg. 53/05 requires the Board to include OPG's revenues and costs for Bruce in the determination of the payment amounts for the Pickering and Darlington nuclear stations. OPG forecast net Bruce revenues for the test period of $134.4 million, which OPG deducted from the nuclear revenue requirement to determine the payment amounts for Pickering and Darlington. This chapter addresses the question of whether OPG has

[71] Bruce Power L.P. is a partnership among Cameco Corporation, TransCanada Corporation, BPC Generation Infrastructure Trust, a trust established by the Ontario Municipal Employees Retirement System, the Power Workers' Union and The Society of Energy Professionals.

used an appropriate method to calculate the revenues and costs for the test period for Bruce.

OPG proposed to include certain 2007 costs related to the Bruce nuclear liabilities in the deferral account established by Section 5.1 of the regulation. That issue is addressed in Chapter 5 of this decision.

Paragraphs 9 and 10 of Section 6(2) of O. Reg. 53/05 state:

> 9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.
>
> 10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2 [Pickering A, Pickering B, and Darlington].

OPG proposed that the test period revenue requirement for Pickering A, Pickering B and Darlington be reduced by approximately $134 million in respect of net revenues related to Bruce. OPG's forecast test period revenues and costs for the Bruce stations are shown in Table 6-1, together with actual 2007 amounts calculated on a comparable basis.

Some of the forecast revenues and costs included in OPG's application in respect of Bruce were determined in accordance with Canadian GAAP applicable to a non-regulated entity. OPG calculated certain other costs and revenues using other accounting bases. The significant non-GAAP policies used by OPG were:

- OPG used a cash basis of accounting for revenue from the Bruce lease. Had OPG computed the revenue in accordance with GAAP, the lease revenue for the test period would have been approximately $30 million more than shown in OPG's application.
- OPG's calculation of the net revenues related to Bruce omits both the accretion expense on the fixed asset removal and nuclear waste management liabilities related to the Bruce stations and the earnings on the related segregated funds.

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Table 6-1: OPG's Calculation of Excess Bruce Revenues

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenue:			
Lease with Bruce Power	$ 252.8	$ 257.4	$ 263.2
Services revenue	48.1	19.7	12.6
Total revenue	**300.9**	**277.1**	**275.8**
Costs:			
Depreciation	120.6	77.5	66.7
Property tax	13.8	15.2	15.5
Capital tax	2.8	2.6	2.5
Used fuel storage and management	13.3	14.1	14.8
Interest	37.6	28.4	27.6
Income tax	-	-	-
Return on equity	27.7	70.2	66.1
Total costs	**215.8**	**208.0**	**193.2**
Revenue less costs	**$ 85.1**	**$ 69.1**	**$ 82.6**
9/12's of 2008 net revenue			51.8
Offset to test period revenue requirement			**$ 134.4**

Sources: Ex. G2-2-1, Tables 1 and 3; Ex. K1-1-1, Tables 1 and 2.

- OPG has proposed to use the same "rate base method" to calculate the cost of the Bruce nuclear liabilities as it proposed to use for the nuclear liabilities of the prescribed facilities. Under that approach, the net book value of OPG's fixed assets related to the Bruce stations was considered to be part of the rate base on which OPG calculated a return on capital. Table 6-1 shows that OPG has included a return on equity as a cost of the Bruce lease. That cost would not be included in an income statement prepared in accordance with GAAP. The return was calculated using the same deemed capital structure (42.5% debt and 57.5% equity) and 10.5% ROE that were proposed by OPG for the prescribed facilities.
- The interest expense in Table 6-1 has also been calculated using the rate base method, which results in the inclusion of deemed interest expense, which is greater than the amount that would be recorded under GAAP.
- OPG's calculation of costs does not include any income tax provision.

The GAAP approach to calculating OPG's revenues less costs for the Bruce stations would result in a substantially higher net revenue amount than would OPG's proposed approach. The pre-tax amounts determined under the two different approaches are reconciled in Table 6-2.

Table 6-2: Bruce Revenues and Costs: Reconciliation of OPG's Calculation with GAAP

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenues less costs per OPG (Table 6-1)	**$ 85.1**	**$ 69.1**	**$ 82.6**
Add:			
Adjust lease revenue to accrual accounting	20.7	20.7	15.5
Eliminate deemed interest expense	37.6	28.4	27.6
Eliminate return on equity	27.7	70.2	66.1
Eliminate deemed capital taxes	2.8	2.6	2.5
Expenses recorded in nuclear deferral account	3.5	-	-
Earnings on segregated funds	194.2	234.9	262.0
Deduct:			
Accretion on nuclear liabilities	(207.2)	(255.9)	(282.0)
Interest on actual debt	(20.3)	(21.2)	(21.1)
Actual capital taxes	(1.1)	(4.4)	(3.6)
GAAP income before tax	**$ 143.0**	**$ 144.4**	**$ 149.6**

Source: Ex. J8.1, page 6.

OPG noted that Section 6(2)9 of O. Reg. 53/05 requires the Board to ensure OPG recovers "all the costs it incurs" with respect to the Bruce stations. OPG argued that it is clear that a return on equity in respect of OPG's investment in the Bruce stations is a cost incurred by OPG. OPG submitted that Section 6(2)8 of the regulation, which requires the Board to ensure OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan, is not restricted to nuclear liabilities related to the prescribed facilities. Rather, OPG contends that Section 6(2)8 is of general application and must be applicable to the Bruce liabilities because those liabilities arise from OPG's approved reference plan under ONFA. OPG submitted: "Nothing about the legislative purpose of O. Reg. 53/05 demands excluding Bruce nuclear waste and decommissioning liabilities from the determination of OPG's revenue requirement."[72]

[72] OPG Reply Argument, page 115.

OPG claimed that its proposed treatment of Bruce lease costs, including the use of the rate base method, is the same as that recommended by CIBC World Markets in its December 2004 report (the "CIBC report"). That report stated:

> Based on CIBC World Markets' analysis and the objectives of the Province previously stated, we believe that the revenues from the Bruce lease, net of OPG's costs for these assets, should be included as part of the regulated rate base, which has the effect of lowering the regulated rate for OPG's nuclear assets.[73]

OPG also claimed that its proposed treatment is the same as the treatment used by the Province to set the existing payment amounts. OPG submitted that the policy issue of how much of the Bruce lease revenues the government intended to be used to offset the revenue requirement for Pickering and Darlington is made clear from the government's decision to include the Bruce fixed assets in OPG's rate base during the interim period. OPG argued that this interim period treatment is "strong evidence that the cost arising from the 'rate base' approach to recovering nuclear waste management was intended to qualify under Section 6(2)9 of O. Reg. 53/05 as a 'cost' which OPG 'incurs' with respect to the Bruce stations."[74]

OPG also provided its opinion on what the Province knew, and what the Province assumed, when it set the current payment amounts:

> ...it was well known to the Province that the interim rates that it approved for the 2005 to 2008 period reflected costs associated with Bruce A and B nuclear liabilities. Not only did the province assume that "costs incurred" with respect to the Bruce facilities included nuclear liabilities associated with the Bruce facilities, it also assumed, for purposes of interim rates, that the proxy for the recovery of that cost was the return on the value of the Bruce NGS fixed asset, i.e., the "rate base method." ... [T]he fact that interim rates employed the rate base method for the recovery of nuclear liability costs and the fact that the Province was aware, before the application was made, of what OPG was seeking in this case, while not binding on the OEB after April 1, 2008, are powerful evidence of surrounding circumstances, which must be considered in determining the meaning and intent of sections 6 (2) 7 to 10 of the Regulation.[75]

OPG asserted that "common sense" and "common regulatory practice" support a conclusion that return on equity is a "cost" under Section 6(2)9 of the regulation.

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[73] CIBC Report, page 20.

[74] OPG Argument-in-Chief, page 87.

[75] OPG Reply Argument, pages 113 and 114.

Board staff took the position that Section 6(2)8 of the regulation, which deals with recovery of the revenue requirement impact of OPG's nuclear liabilities, is applicable only to the cost of the nuclear liabilities related to the prescribed nuclear facilities, Pickering and Darlington. Board staff submitted that the relevant sections of the regulation with respect to the OPG's test period costs for Bruce are Sections 6(2)9 and 6(2)5. Staff submitted that it is appropriate for the Board to determine the Bruce costs incurred and revenues earned by OPG in the test period:

> ... by giving those terms ("cost" and "revenues") the meaning they would ordinarily have in the context of rate-setting applications (including those based on a cost-of-service application). In other words, the Board should use generally accepted accounting principles applicable in a rate setting environment to determine what constitutes a cost with respect to Bruce Facilities.[76]

CCC submitted that the Board should exclude a return on Bruce assets when calculating costs recoverable under Section 6(2)9 of the regulation. CCC contended that O. Reg. 53/05 does not guarantee OPG a return on the Bruce assets.

CME argued that the only reasonable interpretation of Sections 6(2)9 and 6(2)10 of the regulation is that "nuclear liability costs attributable to Bruce are only recoverable to the extent that Bruce costs exceed Bruce revenues."[77] CME argued that the total amount of the "rate base method" elements of OPG's calculation of Bruce costs – deemed interest expense, return on equity, and deemed capital taxes – should not be recovered. CME calculated that by including those items as costs, OPG has understated the excess of its Bruce revenues over costs for the test period by $171 million.

CME submitted that whether the word "costs" in Sections 6(2)9 and 6(2)10 should be construed to include a return on Bruce assets is a question for the Board to resolve. In CME's view, the Board is not bound by the method used to set initial rates. CME contended that there is nothing in the regulation that supports OPG's contention that "costs" must include a profit or return. It also submitted that OPG's interpretation of the regulation would result in OPG earning a guaranteed return on its Bruce investment, a result CME argued was not intended by O. Reg. 53/05.
VECC adopted CME's submission on the proper interpretation of the regulation with respect to the Bruce assets.

[76] Board Staff Argument, page 10.

[77] CME Argument, page 16.

In its reply, OPG stated that CME, VECC and Board staff argued that "OPG has no right to any recovery of the cost of nuclear liabilities, however calculated, with respect to the Bruce facilities."[78] OPG submitted that those arguments are based on a "profoundly and patently unreasonable misinterpretation of the Regulation which, if adopted, would constitute grounds for reversal on a matter of law".[79]

OPG objected to CME's submission that nuclear liability costs for the Bruce stations are only recoverable to the extent that Bruce costs exceed Bruce revenues. OPG submitted that Sections 6(2)9 and 6(2)10 "can only be read to mean that any credit to the revenue requirement arising from the Bruce facilities is after recovery of *all costs incurred* with respect to those facilities."[80] (emphasis in original)

Board Findings

The Board agrees with OPG that O. Reg. 53/05 requires the Board to ensure that OPG recovers all of its costs with respect to Bruce. The language in Section 6(2)9 ("all the costs it incurs") is clear and unambiguous.

The Board also finds that costs related to the Bruce nuclear liabilities are costs for the purposes of Sections 6(2)9 and 6(2)10. As owner of the Bruce stations, OPG has the obligation to manage nuclear waste and to decommission the plants, and that obligation gives rise to substantial costs. Although there are different views about how those costs should be measured, there was no evidence in this proceeding that OPG will not be incurring costs during the test period in respect to the Bruce nuclear liabilities.

The Board also finds that any reduction in the payment amounts for Pickering and Darlington pursuant to Section 6(2)10 should take into account the amount of the Bruce costs required to be recovered under Section 6(2)9. The Board does not agree with CME's interpretation that Bruce nuclear liability costs are only recoverable to the extent that Bruce costs exceed Bruce revenues. As the Board understands CME's position, no costs related to the Bruce nuclear liabilities are recoverable by OPG whenever Bruce revenues exceed Bruce costs. In the Board's view, Section 6(2)10 does not in any way limit the Section 6(2)9 requirement that the Board ensure recovery of all costs incurred.

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[78] OPG Reply Argument, page 112.

[79] Ibid.

[80] OPG Reply Argument, page 116.

The remaining issue is determining how the test period revenues and costs related to the Bruce stations should be measured. As noted earlier in this chapter of the decision, OPG has computed some test period revenues and costs for Bruce in accordance with GAAP but, in other cases, has used non-GAAP measures or included items that would not qualify as costs under GAAP.

In making its determination on how OPG's Bruce-related revenues and costs should be calculated for purposes of Sections 6(2)9 and 6(2)10 of the regulation, the Board first considered why the Province directed that any revenues or expenses related to Bruce should be included in the calculation of the payment amounts for Pickering and Darlington. In the Board's experience, it is unusual to decrease (or increase) rates for a regulated service by using the profits (or losses) of a separate, unregulated business that happens to be owned by the same entity.

OPG's involvement with the Bruce stations is quite different from its involvement with Pickering and Darlington. For example, the Board (and previously the Province) regulates the prices for energy production from the prescribed facilities. In contrast, the lease payments charged by OPG to Bruce Power (and the prices charged for engineering and other services) are the result of a commercial contract; they are not regulated by the Board or any other body. In addition, OPG operates the Pickering and Darlington plants and is responsible for offering the energy produced into the IESO electricity market. The Bruce plants are operated by Bruce Power, not OPG.

There was very little in the evidence in this hearing that explained why the regulation requires the Board to consider OPG's Bruce-related revenues and costs. The Bruce stations were not identified in the August 2004 draft regulation and consultation paper that was issued for public comment by the Ministry of Energy.[81] The first references to using Bruce revenues to reduce the payment amounts for the prescribed facilities appear to be in the December 2004 CIBC report. The executive summary of that report states:

> **OPG's Regulatory Construct**: We took as the starting point for OPG's regulatory construct the draft regulation and consultation paper for the initial rates for OPG's price regulated plants issued by the Ministry of Energy in August 2004. Following discussions with officials at the OFA and Energy, and based on its analysis, we provided several additional recommendations or variances from the draft consultation regulation and paper, as follows:

[81] The draft regulation and consultation paper are reproduced in Appendix J to the CIBC report.

- Use as an offset to OPG's regulated revenue requirement, OPG's revenues from the lease of its Bruce assets to Bruce Power, net of OPG's costs, which reduces the regulated rate.[82]

The CIBC report also notes that: "Whether these OPG assets are included or excluded under the regulation of OPG is a governmental policy issue rather than one that can be evaluated from regulatory precedents."[83]

Although not stated explicitly in any document issued by the Province to the Board's knowledge, it appears that the inclusion of the Bruce net revenues is essentially a mitigation measure. This view is supported by testimony of an OPG witness, who agreed that the inclusion of Bruce revenues and costs in the calculation of the payment amounts was intended to provide shelter against higher payments on the prescribed assets.[84]

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

Further, the Board finds that the Bruce net revenues, as a mitigation measure, do not form part of OPG's revenue requirement for the prescribed assets. Rather, the Board concludes that the regulation requires net revenues be used to reduce the payment amounts that would otherwise be set based on the revenue requirement for the prescribed assets. In the Board's view, "revenue requirement" is a concept that is applicable only to rate-regulated activities.

OPG advanced two arguments in support of its position that the rate base method should be used when calculating Bruce test period costs.

First, OPG has submitted that its use of the rate base method to calculate Bruce test period costs is consistent with the recommendations in the December 2004 CIBC report.

[82] CIBC report, page 2.

[83] CIBC World Markets report, page 20.

[84] Transcript, Volume 7, page 36.

It is true, as OPG notes, that page 20 of the CIBC report mentions "regulated rate base" when it refers to the Bruce stations. The Board is not convinced, however, that those words refer to OPG's "rate base method" because the CIBC report uses different, and inconsistent, terminology when it discusses CIBC's recommended treatment for the Bruce lease. For example, the CIBC report refers, in one place, to including "revenues from the lease of Bruce" in rate base, a concept that is difficult to understand because assets, not revenues, are included in rate base.[85] The Board also notes that other parts of the CIBC report that discuss the Bruce lease do not mention rate base at all but refer simply to using revenues from the Bruce lease as an offset to "OPG's regulated revenue requirement"[86] or to including "lease cash flows from Bruce Power."[87]

The CIBC report also states that rate base "reflects a company's investment in assets related to its regulated business,"[88] which, in OPG's case, does not include its investment in Bruce, an unregulated business.

In short, after reviewing the CIBC report to determine if it recommended the rate base method for calculating the Bruce test period costs, the Board is of the view that it did not.

OPG's second argument was that when the Province set the initial payment amounts for the prescribed facilities, it deducted net revenues for the Bruce lease that had been calculated using the rate base method.

Aside from OPG's claim, no evidence has been filed with this Board that sets out how the initial payments were calculated by the Province. The Board was unable to determine what was included in the rate base amount shown in the CIBC report; in any event, the initial payment amounts struck by the Province were different than the amounts set out in the CIBC report. The Board notes that a February 23, 2005 presentation on the payment amounts by Ministry of Energy officials indicated only that: "Earnings from the Bruce Nuclear Lease incorporated [sic] in the setting of the regulated

[85] CIBC Report, page 20.

[86] CIBC Report, pages 2, 27 and 34.

[87] CIBC Report, page 26.

[88] CIBC Report, page 10.

price of nuclear."[89] The term "earnings" does not suggest any particular basis of calculation.

The Board also notes that the "rate base" amount included in OPG's application is restricted to assets related to the prescribed facilities. No amounts related to the Bruce stations are included.

The Board concludes that the evidence is unclear as to whether the Province used the rate base method to calculate the net revenues for the Bruce lease when it set the initial payment amounts. Even if the rate base method were used to set the initial payments, however, the Board concludes it is not bound to continue that approach after April 1, 2008.

The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would not be a reasonable interpretation of Sections 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use. Had the Province intended the Board to determine revenues and costs related to Bruce in accordance with principles applicable to a regulated business, the regulation would have so stated.

OPG proposed to calculate Bruce lease revenue for the test period in accordance with a policy that would not be acceptable for an unregulated commercial entity. The company's rationale for following a cash basis of accounting for lease revenue, rather than a GAAP basis, is not clear to the Board.

OPG took the position that O. Reg. 53/05 requires the Board to accept OPG's cash basis accounting policy for Bruce lease revenue. Section 6(2)5 of the regulation requires the Board to accept certain amounts that are set out in OPG's 2007 audited financial statements, including "OPG's revenues earned with respect to any lease of the Bruce Nuclear Generating Stations." Section 6(2)6 stipulates that section 6(2)5 applies to "values relating to ... the revenue requirement impact of accounting and tax policy decisions." OPG claimed that Section 6(2)6 obligates the Board to accept the

[89] Ministry of Energy, "Technical Briefing on OPG Pricing Announcement," February 23, 2005, page 8. [Exhibit J1.4]

accounting policy that was used by OPG to record lease revenue in 2007 when the Board determines OPG's Bruce lease revenue for the test period.

The Board does not accept that it is required to use the cash basis of accounting to calculate the test period revenues for the Bruce lease. In the Board's view, section 6(2)5 obligates the Board to accept the book values of assets and liabilities as at December 31, 2007 and requires the Board to accept the accounting policies that were used to compute those book values. Bruce lease revenue for the test period, an <u>income statement</u> amount for a period <u>subsequent</u> to 2007, is clearly not an asset or liability that is set out in OPG's 2007 financial statements. Those financial statements show lease revenue for 2007; the financial statements are not projections or forecasts of future revenues.

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

The Board directs OPG to revise its calculation of the net test period revenues related to Bruce as follows:

1. The rate base method should not be used to calculate OPG's costs in respect of Bruce. That means that "costs" should exclude the return on equity and deemed interest expense that flow from the rate base method.
2. OPG should base its calculation of costs on GAAP. The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs.
3. OPG should calculate lease revenue in accordance with GAAP.
4. OPG should include an income tax (PILS) provision, calculated in accordance with GAAP, in its computation of Bruce costs. OPG proposed to exclude income taxes on the basis that there are tax loss carry forwards available to the regulated businesses. As OPG's Bruce investment is not regulated by the Board,

the Board sees no basis for omitting a tax provision in the calculation of Bruce costs.

The net effect of these findings is that any profit (or loss) in respect of OPG's Bruce lease, calculated in accordance with GAAP, will increase (or decrease) the payment amounts for the prescribed assets. Under this approach, the payment amounts for the prescribed assets are likely to be lower in all cases than the payment amounts calculated under OPG's interpretation of O. Reg. 53/05. When OPG earns a profit (measured in accordance with GAAP) on its Bruce activities, the Board's approach calls for all of that profit to be used to reduce the payment amounts for Pickering and Darlington. OPG's approach would result in a smaller offset to the payment amounts because OPG would include a regulated return on its Bruce investment as a cost. If OPG were to incur a loss on its Bruce activities, which could happen if there are significant increases in the Bruce nuclear liabilities in the future, that loss would increase the payment amounts for the prescribed assets under the Board's approach. OPG's approach likely would result in a greater increase to the payment amounts, again because OPG would include a regulated return on its Bruce investment as a cost.

Under OPG's approach, as CCC and CME pointed out, electricity consumers would in effect be guaranteeing that OPG earns a return on its Bruce fixed assets. The Board has no evidence that supports such an approach, and believes the effect of such an approach on the nuclear payment amounts would not be reasonable. Under O. Reg. 53/05, electricity consumers, not OPG, are exposed to the risk that they will have to absorb, through higher payment amounts for the prescribed assets, any losses related to Bruce in the future. It is, therefore, appropriate that when OPG earns profits on its Bruce activities that consumers receive the full benefit of those profits, without deduction of a regulated return as proposed by OPG.

Calculating revenues and costs in accordance with GAAP will result in a higher excess of Bruce-related revenues over costs for the test period than the $134.4 million proposed by OPG. The Board estimates that the excess revenues under the GAAP approach are approximately $175 million (based on the GAAP pre-tax income amounts in Table 2, adjusted to reflect a 21-month test period, and tax rates of 31.5% in 2008 and 31.0% in 2009 as specified in OPG's application). The precise amounts will be determined by OPG and filed with the Board.

OPG did not apply for a variance account for test period revenues and costs in respect of the Bruce stations. Section 6(2)9 of the regulation requires the Board to ensure that OPG recovers all of its costs related to the Bruce stations. In the Board's view, this section obligates the Board to ensure OPG recovers its actual, not forecast, costs related to Bruce. Section 6(2)10 requires that the excess of revenues earned in respect of the Bruce stations over the costs incurred by OPG should reduce the payment amounts for the prescribed facilities. In the Board's view, this section obligates the Board to ensure that the actual, not forecast, excess of revenues over costs is used to offset the payment amounts for Pickering and Darlington. Accordingly, the Board directs OPG to establish a variance account to capture differences between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG's actual revenues and costs in respect of Bruce. The cost impact of any changes in nuclear liabilities related to the Bruce stations should be recorded in this account, not the nuclear liabilities deferral account required by Section 5.2 of the regulation.

7.3 Test Period Deferral & Variance Accounts

SMO and water transactions

In Chapter 3, the Board determined that revenues from SMO and water transactions would not be subject to variance account treatment, so there is no need for the Board to approve the proposed variance account.

Pension interest rate

The Board does not approve the proposed variance account related to changes in the discount rate used for pensions and OPEBs. The Board acknowledges that changes in the discount rate are outside OPG's control but that is true of many elements of OPG's proposed revenue requirement.

It has not been the Board's practice to allow regulated entities to establish variance accounts for changes in the costs of pensions and other benefits although there have been a few exceptions, as noted by OPG. The Board does not consider the two Board decisions on Hydro One's pension deferral accounts, which were cited by OPG, to be analogous to OPG's proposal. Unlike the account OPG has requested, the deferral account that Hydro One Distribution sought, and was granted, in 2004 was not intended to capture changes in pension costs that had not occurred but that might arise due to future changes in economic factors. Rather, the Hydro One Distribution account was established for known and material increases in pension costs above the amount included in rates.[93] The other Hydro One pension deferral account referenced by OPG (an account established in 2007 for Hydro One Transmission) was part of a settlement agreement accepted by the Board. As the Board has noted on other occasions, specific elements of settlement agreements have limited precedential value.

In the event that OPG's actual pension and OPEB costs during the test period are materially in excess of the amounts included in the revenue requirement, OPG would have the ability to apply to the Board.

Income and other taxes

The Board approves the variance account to track variations in municipal property taxes, and variations in payments in lieu of capital taxes, property taxes, and income taxes. The Board has authorized a tax variance account for electricity distributors (Account 1592, which deals with tax variances after April 2006[94]) that is used to record

[93] RP-2004-0180/EB-2004-0270, Decision and Order, July 14, 2004.

[94] Account 1592 is described in the Board's Accounting Procedures Handbook for Electric Distribution Utilities.

variations due to changes in tax rates or rules, new assessing or administrative practices of tax authorities, and tax re-assessments for past periods. The events and circumstances that give rise to entries into Account 1592 are essentially the same as those proposed by OPG, except that OPG includes court decisions for other taxpayers that will affect OPG's tax position. The Board finds that OPG's inclusion of variations due to court decisions for other taxpayers is appropriate.

The Board does not accept CCC's argument that only variances due to tax re-assessments for periods after April 1, 2008 should be permitted. The Board does not consider it appropriate to make use of the account more restrictive than Account 1592 is for electricity distributors.

With respect to income taxes, it is necessary to determine what the benchmark should be for measuring variations due to changes in tax laws and other factors. OPG did not address this issue in its evidence or argument. This is complicated by the fact that OPG did not include any provision for income taxes in its proposed revenue requirement on the basis that there are tax loss carry forwards for regulatory purposes. As set out in Chapter 9, the Board is uncertain about whether such regulatory tax loss carry forwards exist and, if they do, whether OPG was required to adopt the approach it took in its application.

To establish a benchmark to measure variations in taxes during test period, the Board directs OPG to calculate the income tax provision, before consideration of any tax loss carry forwards, which would result from the revenue requirement determined in accordance with this decision. That tax provision will not form part of the test period revenue requirement but should be used by OPG to calculate any variations in taxes that it records in the variance account.

The appropriateness and recovery period of any balance in the tax variance account will be reviewed by the Board when it considers OPG's next application. The Board notes that it has commenced a proceeding to deal with the disposition of Account 1562 (the tax variance account for electricity distributors for periods before May 2006) and that proceeding is expected to deal with variations in taxes due to tax audits and reassessments for past periods.[95] In a future hearing when the Board reviews any

[95] The Account 1562 proceeding (EB-2007-0820) was announced in March 2008. A staff discussion paper on the issues was released on August 20, 2008.

balance in OPG's tax variance account related to re-assessments, it will take note of any relevant decisions made by the Board in the Account 1562 proceeding.

7.3.3 New accounts proposed by intervenors

Two intervenors suggested that OPG be required to establish additional variance and deferral accounts.

In connection with its submission that the Board should cut OPG's proposed regulatory costs by 50%, CCC stated that OPG could establish a regulatory cost variance account to capture deviations from budget as OPG gains more experience with regulatory forecasting.

AMPCO recommended a variance account be approved in connection with its proposal that OPG be required to share 50% of any Congestion Management Settlement Credits received by OPG from the IESO, net of incremental costs.

AMPCO also proposed a variance account to capture variances between actual and forecast non-energy charges from the IESO (which OPG pays when the prescribed facilities consume power). AMPCO said these charges are difficult to forecast and submitted that OPG's forecasting methodology is questionable.

OPG did not agree that these accounts are required. It said its test period budget for regulatory costs is appropriate because it plans to file another cost of service application with the Board in 2009. It disagreed with AMPCO's submission that there is any net revenue from CMSC payments. And it disputed AMPCO's claim that OPG's forecasting methodology is suspect.

Board Findings
The Board agrees with OPG comments on the proposed accounts. It will not require OPG to establish the accounts. As noted in Chapter 4, the Board accepts OPG's forecast of regulatory costs and found a variance account is not required.

7.4 Interest Rates

OPG proposed that, for all deferral and variance accounts except PARTS, interest after March 31, 2008 should be accrued on the account balances at OPG's forecast rate for

8.3.2 The stand-alone principle

OPG also noted Ms. McShane's testimony that the circumstances suggest that the Province is trying to establish an arm's-length company and concluded as follows:

> To proceed on the assumption that the shareholder will intervene to protect OPG as an argument for ignoring the stand-alone principle directly contradicts the province's decision to place OPG's prescribed assets under the independent jurisdiction of the OEB.[106]

Board Findings

The stand alone principle is a long-established regulatory principle and the Board has considered its application in a variety of circumstances. The unique circumstances of OPG, however, are in many ways without precedent. As noted above:

- Both the regulated and non-regulated operations perform the same function (i.e., generate power).
- The owner is the Province.
- The Board's approach to setting the payments now and in the future have in some respects been determined by the Province (through O. Reg. 53/05).

OPG is also different from the other entities the Board regulates in that it is not a natural monopoly.

Risk, in the regulatory context, can be considered to be the magnitude of the range of potential outcomes, with the focus generally being on the potential for an adverse outcome. In other words, the greater the range of potential outcomes, the greater is the risk. The Board is faced with two questions when considering the appropriate application of the stand-alone principle in the assessment of risk for OPG:

- Should OPG's risk be considered lower than other regulated Ontario energy utilities because the Province as owner has substantial control over OPG's risks – either in creating them or in protecting OPG from them (shifting the risk to consumers)? This is the issue of the shareholder impact on a regulated entity's risk.
- Is the political risk higher for OPG's regulated assets than for other regulated Ontario energy utilities? This is the issue of the impact of electricity policy changes on risk.

[106] OPG Reply Argument, p. 16

The witnesses and the parties generally agreed that deferral and variance accounts affect the level of risk and reduce it from what it would otherwise be. Similarly, where O. Reg. 53/05 mandates the recovery of certain costs, it is agreed that this reduces risk. O. Reg. 53/05, and in particular the establishment of various deferral and variance accounts and the requirement that certain types of cost be recovered, operates to transfer risk from OPG to customers. The Board must consider the precise nature of the accounts and determine the impact on risk; this is discussed in more detail later in this chapter.

In summary, some of these protections relate to expenditures before the period of Board regulation (the PARTS account) or to activities beyond the operation of the prescribed facilities (recovery of Bruce costs and new nuclear costs). These do not affect the level of risk for the prescribed facilities in the test period. Some of the accounts are comparable to the accounts of other regulated entities; they have not been stipulated through O. Reg. 53/05 for the test period, but rather have been approved by the Board (the accounts related to tax changes, water conditions, nuclear fuel expense, and ancillary service revenues). OPG also applied for other accounts, which the Board has decided not to approve (OPEB changes and SMO and WT revenues).

Two significant protections related to the prescribed assets have been established by O. Reg. 53/05 and will be ongoing: changes in nuclear liabilities and refurbishment costs. These are significant additional protections which have been established by the government and exceed the level of protection typically granted to a regulated utility.

The Board's conclusion is that these accounts do reduce risk. The Board notes, however, that under O. Reg. 53/05, amounts placed in the deferral and variance accounts after the Board's first order will be subject to a prudence review. These accounts will operate the same way for OPG as they do for other regulated entities, although the breadth of protection is greater.

While OPG's risk is lower due to these accounts, should OPG be considered of even lower risk because the shareholder can control whether OPG's financial risks are borne by the customers or the shareholder? The Board concludes that it should not. To conclude that OPG is of lower risk would be comparable to assuming that, after the Board's first order, the Province will direct the regulation of the prescribed assets, and regulate the distribution of risks between OPG and its customers, beyond the protections already established and assessed for purposes of setting the capital structure. O. Reg. 53/05 is viewed by the Board as setting the baseline for OPG as it enters into a formal regulatory framework; essentially limiting any review of activities in the period prior to the Board's payment setting mandate and requiring protection against forecast error (subject to a prudence review) for certain significant costs going forward. The Board concludes that if OPG is operated at arm's length, then it should be examined in the same way as Hydro One, another energy utility owned by the Province. In other words, Provincial ownership will not be a factor to be considered by the Board in establishing capital structure.

The Board must also consider how it will address the shareholder's ability to control future risk. If the Province transfers risks from OPG to consumers in future, then the Board would need to assess the resulting level of risk and adjust the risk ranking (and possibly the capital structure) accordingly.

OPG suggests that its regulated assets are subject to greater political risk than other energy utilities in the province. The Board does not agree that this is a risk that should be reflected in OPG's cost of capital. All of Ontario's energy utilities are subject to risks arising from changing energy policy. The Province has established cost recovery requirements for utilities in which it has no ownership (for example, the regulations related to smart meter implementation). For example, the Province also required the LDCs to spend the third tranche of their market rates of return on conservation and demand management expenditures. The Board concludes that OPG's exposure to the risks and benefits of Provincial direction regarding expenditures and cost recovery are comparable to that of other regulated utilities.

The Board finds no evidence that OPG's regulated hydroelectric and nuclear facilities will be uniquely exposed. Mr. Goulding's evidence suggests that the risk of political interference is higher for OPG, but precisely because the Province is the owner and may choose to use OPG in a way which would be adverse to OPG's financial interests. It would not be appropriate for the Board to assume that the Province will interfere in the distribution of OPG's risks now that the Board has regulatory authority over OPG; it is consistent therefore to regulate OPG on the basis that the Province will not control OPG's currently regulated facilities in a manner which is adverse to OPG's commercial interests. The stand alone principle leads us to conclude that OPG's financial risks are not lower as a result of Provincial ownership; therefore it is consistent to conclude that political risk is not higher as a result of Provincial ownership.

9.1 Tax Losses & Rate Mitigation

9 DESIGN AND DETERMINATION OF PAYMENT AMOUNTS

9.1 Tax Losses and Rate Mitigation

OPG proposed to reduce the test period revenue requirement by $228 million because it "recognizes that the revenue requirement increase over the current payment amounts is significant and will have an impact on electricity consumers."[128] OPG characterized this mitigation as an acceleration of the application of regulatory tax loss carry forwards that OPG claimed existed at the end of 2007 and that would not be utilized in 2008 or 2009.

OPG said its regulatory tax losses at December 31, 2007 were $990.2 million. It forecast that $487 million of that amount would be used in 2008 and 2009, leaving $503.2 million available for subsequent periods.[129]

In addition to this mitigation, OPG decided not to recognize any provision for payments in lieu of income taxes (PILs) in the test period. PILs payments are calculated in accordance with federal and Ontario tax laws but are paid to the Ontario Electricity Financial Corporation. Assuming the Board were to approve its application as filed, OPG estimated that its regulatory taxable income, before consideration of the regulatory tax losses, would be $487 million for the two years ended December 31, 2009. At currently enacted tax rates, the PILs payments would be approximately $150 million for that period. The amount of PILs for the 21-month test period related to the prescribed facilities would be lower than that amount but would still be quite substantial.[130]

OPG calculated the accumulated "regulatory tax losses" of $990.2 million at the end of 2007 by computing the taxable income or loss since April 1, 2005 of the prescribed facilities (plus the Bruce lease). OPG indicated that the main reasons for the regulatory tax losses were:

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[128] Exhibit K1-1-2, page 1.

[129] Exhibit F3-2-1, Table 9.

[130] The Board was not able to calculate even a rough estimate of the amount of PILs for the test period for the prescribed facilities because regulatory taxable income as calculated by OPG includes taxable income related to OPG's Bruce lease. Also, the 2008 PILs amount provided by OPG is for a full year, not nine months.

- OPG made substantial tax-deductible contributions to the segregated nuclear funds (contributions during the period were $888 million, including a special one-time payment of $334 million in 2007 related to the Bruce facilities);
- the deduction in 2005 of $258 million in Pickering A return to service costs; and
- a loss before income tax from the prescribed facilities in 2007.

OPG referred to its accumulated loss carry forwards as "regulatory tax losses" to distinguish them from actual tax loss carry forwards that are recognized by the tax authorities. In fact, OPG's witnesses noted that OPG did not have any actual tax loss carry forwards at the end of 2007. The benefit of all tax losses that were generated by the prescribed facilities during the period 2005 to 2007 were used to reduce PILs payable by OPG in respect of its unregulated operations. OPG's witnesses also noted that in its consolidated financial statements for 2005 through 2007, OPG recorded the benefit of those "regulatory tax losses" in earnings; it did not credit any of the benefit of those losses to a deferral account to be used to reduce the payment amounts for the prescribed assets after April 1, 2008.

In its argument, OPG submitted that: "While an argument could be made that these tax losses belong to OPG and not to ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is appropriate that they be returned to ratepayers."[131]

Only a few intervenors commented on OPG's proposed mitigation and its elimination of a tax provision for 2008 and 2009. CCC, CME and SEC supported OPG's approach. CCC and SEC noted that, absent the mitigating effect of the tax losses, the increase in payment amounts sought by OPG would be much higher than proposed in its application. CME supported OPG's approach and noted that OPG was not obliged to allocate the benefit of the prior period tax losses to consumers.

Board Findings

OPG's proposals to exclude a tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million mitigation amount are both linked to the $990.2 million of "regulatory tax losses" that OPG claims existed at December 31, 2007.

[131] OPG Argument-in-Chief, page 109.

OPG's tax calculations did not receive much scrutiny during this proceeding. Although intervenors supported OPG's proposals (or were silent on the issues), the Board is not convinced that OPG has taken the right approach to income tax issues in its application.

The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct. Reasons for the Board's concerns about OPG's treatment of taxes include:

- OPG's calculation of regulatory tax losses for 2005 to 2007 includes revenues and expenses related to OPG's Bruce lease. The Bruce stations are not prescribed facilities and OPG's Bruce lease is not regulated by the Board. In the Board's view, any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease.[132]
- OPG did not have any tax loss carry forwards at the end of 2007. OPG's witnesses confirmed that OPG was able to use the tax losses generated by the prescribed facilities for period 2005 to 2007 to reduce the income taxes that OPG would otherwise have paid in respect of its unregulated businesses. That is, the benefit of the tax losses related to OPG's regulated assets for 2005 to 2007 has already been realized by OPG.
- OPG witnesses confirmed that the benefit of the pre-2008 tax losses in respect of the regulated assets was recorded in OPG's audited financial statements in the form of a lower tax expense. Those witnesses also confirmed that OPG did not establish a deferral account at the end of 2007 to capture the tax benefits it claimed should be used to reduce regulatory taxes for 2008 and later periods in its application. The treatment of tax losses adopted in OPG's financial statements appears to conflict with the position taken in OPG's application to the Board.
- OPG stated that an argument could be made that the regulatory tax losses belong to OPG and not to customers since they arose in a period prior to Board regulation. Nonetheless, OPG submitted it was appropriate that the tax benefits be credited to customers although it offered no reasons why it was considered to be appropriate.

[132] As noted in Chapter 8, the Board has determined that revenues and costs related to the Bruce stations should be calculated for purposes of section 6(2)10 of Regulation 53/05 in accordance with GAAP (not regulatory accounting) and that a tax provision should be included in the Bruce costs.

Although the Board is not convinced that regulatory tax loss carry forwards existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all of the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.

The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss.

- In 2005, OPG deducted $258 million of Pickering A return to service costs in computing taxable income for that year. For accounting purposes, OPG recorded those costs in the PARTS deferral account. As noted in Chapter 7 of this decision, the remaining deferral account balance at December 31, 2007 of $183.8 million will be recovered through future payment amounts for the nuclear facilities. In the Board's view, the majority of the tax benefit realized by OPG in 2005 should be for the account of consumers given that the nuclear revenue requirement after 2007 will include $183.8 million to recover the deferral account balance.
- OPG's evidence indicated that in 2007 its regulated operations incurred an $84 million loss before income taxes (how much of that loss, if any, that relates to Bruce is unclear). It would appear that the operating loss in 2007 was borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.

The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods. The Board has therefore examined the proposed level of mitigation within the context of OPG's overall application.

With respect to 2008 and 2009, the Board is not able to agree, for the reasons outlined above, with OPG's position that "regulatory tax losses" permit it to eliminate an income tax provision. Because there is no evidence about the amount of pre-2008 tax benefits that appropriately should be carried forward to offset 2008 and 2009 PILs, the Board views OPG's proposal to eliminate an income tax provision in the test period as simply mitigation. OPG has effectively agreed to absorb whatever tax provision would otherwise be required for those years. The Board finds that this mitigation should be retained in OPG's calculation of the revenue requirement and payment amounts that flow from the Board's findings in this decision. That is, OPG should not include any tax provision for 2008 and 2009 in respect of the prescribed assets.

As for OPG's proposed $228 million mitigation amount, the Board also does not accept that there is any connection between that amount and any regulatory tax losses. OPG's offer of $228 million of mitigation was made in the context of the revenue requirement, before mitigation, shown in OPG's application. The revenue requirement that results from the Board's findings in this decision will be lower than that proposed by OPG. The Board concludes that it would be unreasonable to hold OPG to its original offer of mitigation. The mitigation amount of $228 million was about 22% of the $1,025.7 million revenue deficiency shown in OPG's application. The amount of mitigation the Board will require OPG to provide for the test period will be equal to 22% of the revenue deficiency calculated based on the Board's findings in the decision. The Board estimates that this amount will be about $170 million, compared to the $228 million in OPG's application.

In its next application for payment amounts for the prescribed assets, the Board will require OPG to file better information on its forecast of the test period income tax provision. To that end, the income tax provision for the prescribed facilities in future applications should not include any income or loss in respect of the Bruce lease. The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. That analysis should be based on the principle that if OPG is proposing that electricity consumers should bear a cost (or should benefit from revenues) they will receive the related tax benefit (or will be charged the related income taxes).

The Board also believes that its assessment of income taxes (and other elements of OPG's proposed revenue requirement) would be improved if OPG were to file a complete set of audited financial statements, including a balance sheet, for the prescribed facilities. The Board regulates the rates of a few utilities that are owned by entities that also own substantial unregulated businesses. Those regulated utilities do file separate audited financial statements as part of their applications. The Board directs OPG to file such audited financial statements for the prescribed facilities. Assuming that OPG's next application is filed in mid-2009, the Board expects OPG to file financial statements as at and for the year ended December 31, 2008.

9.2 Nuclear Payment Structure

9.2.1 OPG's fixed payment of $1.2 billion

OPG requested a change in the structure of payments for the nuclear facilities. The current nuclear payment amount is $49.50 per MWh, with OPG being fully at risk for outages at Pickering and Darlington. OPG proposed that the Board approve a fixed payment of $1,221.6 million (25% of OPG's proposed revenue requirement, net of variance and deferral account amortization), payable in equal monthly instalments. The balance of OPG's proposed nuclear revenue requirement would be recovered through a variable payment amount of $41.50 per MWh and a further $1.45 per MWh to cover clearance of variance and deferral accounts.

OPG argued that it should be awarded a significant fixed payment for the nuclear facilities because over 90 percent of nuclear costs are fixed, and because generators in Ontario and other jurisdictions receive some form of fixed payment. It also noted that the rates for utilities that provide regulated distribution services include a fixed component. OPG acknowledged that receiving a significant fixed payment for nuclear facilities would reduce OPG's risk. It submitted that the variable component of the proposed payment structure would still provide a strong incentive to maximize nuclear unit availability, avoid outages, and bring units back from an outage as quickly as possible.

Intervenors were split on the merits of OPG's proposal. CCC, PWU, SEC supported, or did not object to, a fixed component for nuclear payments. CCC submitted that it is more important to mitigate OPG's risk than to provide a meaningful incentive to avoid unscheduled outages. It recommended that the fixed portion of the nuclear payments be set at 50% of the revenue requirement. PWU and SEC supported OPG's proposed 25% fixed payment.