SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

OPG PANEL 10

TAX LOSS MATERIALS

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.

<u>Regulatory Income Taxes – Current Tax Expense</u>

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:

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

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.

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.

CONSUMER IMPACT

1. PURPOSE

The purpose of this evidence is to provide an illustrative example of the impact of the proposed increase in payment amounts on a typical residential electricity consumer.

2. REVENUE REQUIREMENT

For purposes of this consumer impact analysis, OPG has calculated its mitigated regulated hydroelectric and nuclear revenue requirements for the April 1, 2008 - December 31, 2009 test period on a $/MWh basis, and used the average electricity distributor bill information provided on the OEB's website at:
http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm

The consumer bill impact associated with OPG's deferral and variance account proposals is provided separately, as is the total consumer bill impact of revenue requirement and deferral/variance account recovery.

Based on this analysis, the consumer bill impact of the increase in payment amounts being sought in this application over the test period is about 2.73 percent (or $3.05 per monthly bill) (Ex. K1-T1-S3 Table 1).

Table 1
Typical Residential Consumer Impact Assessment
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period: Regulated Hydroelectric	Test Period: Nuclear	Test Period: Total
		(a)	(b)	(c)
1	**Typical Residential Consumer Usage (KWh/Month)**[1]	1,000.0	1,000.0	1,000.0
2	**Gross-up for Line Losses**[2]	1.0522	1.0522	1.0522
3	**OPG Portion**[3]	11.4%	31.9%	43.3%
4	**Residential Consumer Usage of OPG Generation (KWh/Month)**	119.8	336.0	455.8
	(line 1 * line 2 * line 3)			
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY:			
5	**Test Period Deficiency ($M)**	241.2	784.6	1,025.8
6	**Less: Mitigation ($M)**[4]	90.1	137.9	228.0
7	**Required Recovery ($M)** (line 5 - line 6)	151.1	646.7	797.8
8	**Forecast Production (TWh)**[5]	31.5	88.2	119.7
9	**Required Recovery ($/MWh)**[6] (line 7 / line 8)	4.80	7.33	6.66
10	**Typical Monthly Consumer Bill Impact ($)**	0.58	2.46	3.04
	(line 4 * line 9)			
11	**Typical Monthly Residential Consumer Bill ($)**[7]	111.63	111.63	111.63
12	**Percentage Increase in Consumer Bills**	0.52%	2.21%	2.72%
	(line 10 / line 11)			

Notes:
1. OPG has used consumption information reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm
2. OPG has used the adjustment factor for line losses data reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm
3. Total based on OPG's forecast production divided by the weather normal IPSP energy forecast for 2008 and 2009. Reg. Hydro. and Nuclear portions determined based on energy production.
4. Inclusion of tax losses applicable to future periods as described in Ex. K1-T1-S2
5. From Ex. K1-T1-S1 Table 3
6. Recovery amount is expressed in $/MWh and does not reflect the structure of the payment amount which includes a fixed payment amount for Nuclear.
7. OPG has used the average electricity distributors bill included in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm

Ontario Energy Board

Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

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.

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.

[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.

[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.

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:

[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.

Ontario Energy Board

Commission de l'énergie de l'Ontario

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;

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: Howard Wetston
Presiding Member and Chair

Pamela Nowina
Member and Vice Chair

DECISION AND ORDER ON MOTION TO REVIEW AND VARY
(Notice of Motion filed January 28, 2009)

On January 28, 2009, 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 dated November 3, 2008, file number EB-2007-0905 ("Payments Decision"). The Motion has been assigned file number EB-2009-0038.

On March 2, 2009, the Board issued a Notice of Motion and Procedural Order No. 1 which advised the Board would hold an oral hearing at which the threshold question of whether OPG's Motion raised a substantial question as to the correctness of the Decision, and the merits of the Motion, would be considered concurrently. The Board adopted the intervenors and parties of record from the EB-2007-0905 proceeding. No other parties came forward requesting intervenor or observer status.

The School Energy Coalition ("SEC"), Canadian Manufacturers and Exporters ("CME"), the Power Workers' Union ("PWU"), the Electricity Distributors Association ("EDA"), Board staff and OPG filed submissions in advance of the oral hearing. The Board heard submissions from SEC, CME, PWU and OPG at the oral hearing held on April 3, 2009.

After considering the oral and written submissions, the Board has decided to grant OPG's motion to vary the Payments Decision. The following Decision and Order sets out the reasons of the Board.

Background

Motion Brought November 24, 2008

Prior to the Motion which is the subject of this decision, OPG filed a Notice of Motion dated November 24, 2008 ("Previous Motion") which also sought a review and variance of the Payments Decision. No additional materials were filed.

The Previous Motion requested a review and variance of that portion of the Payments Decision "which purport to de-link 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".[1]

The Previous Motion listed four grounds:

1. the Board's analysis and disposition of the tax loss issue was never advanced before or during the hearing , depriving OPG of the opportunity to respond to the approach;

---

[1] OPG Compendium of Evidence, Tab 1, Previous Motion, p.3.

2. the Board erred in fact and law by failing to recognize regulatory tax loss carry forwards as the basis for the OPG's proposal to mitigate payment amounts in the test period;
3. the Board exceeded its jurisdiction by arbitrarily ordering OPG to make an unqualified gift to consumers, unlawfully depriving OPG of the opportunity to recover its approved costs and return on equity; and
4. the Board was unreasonable in its disposition of the tax loss issue as it appeared intended to result in double counting tax loss credits to consumers.

The Previous Motion described the relief sought as a variance of the portion of the Payments 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 was not an unqualified gift but was unambiguously based on OPG's calculation of prior period regulatory tax losses notionally available to be carried forward into the test period;

(iii) a clear acknowledgement that OPG would, under no circumstances, be found liable to provide credits to customers on account of any regulatory 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 Payments Decision as to the re-calculation of those tax losses.

The Previous Motion made no reference to the Board's *Rules of Practice and Procedure* (the "Rules"), and specifically, no reference to the Rules under which OPG was proceeding; no reference to the powers that OPG sought the Board to exercise on its behalf (for example, no order was sought); no reference to the type of hearing sought; and no reference to the Board's power to determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

On December 19, 2008, the Board issued a Decision and Order which stated:

> 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.

Motion Brought January 28, 2009

Procedural matters related to the Motion

The Motion was filed January 28, 2009, along with a written submission.

Rule 42.03 requires a notice of motion to be filed and served within 20 calendar days of the date of the order or decision for which a review is requested. In a letter accompanying the Motion, OPG acknowledged its late filing and requested the Board give consideration to it nonetheless; the Motion and the written submission sought no specific relief with regard to the late filing.

SEC and CME took issue with the filing of the Motion by OPG given the dismissal of the Previous Motion. In its written and oral argument, SEC expressed concerns that if the Board permitted the Motion to proceed, it would encourage parties to bring repeated review motions until they obtained a sympathetic Board panel, thus undermining the principle of the finality of decisions. SEC argued OPG could only be before the Board on the Motion "if, in principle, a party can keep moving to review or vary a decision of the Board as many times as it likes." SEC urged the Board to exercise control over its own review process by refusing to permit the Motion to proceed.[2]

In its reply and oral submission, OPG responded that the Rules provided ample flexibility to the Board to hear and determine the Motion, without undermining the integrity of the Board's processes. OPG argued that the Rules permitted the Board to receive the Motion if the Board was satisfied the circumstances of the case and the public interest in securing the most just, expeditious and efficient determination on the merits required it to do so.[3]

The Board agrees that finality in decision making is important, as is discouraging motions for review as a means of seeking a sympathetic Board panel; however, the Board views this matter as one which engages broader issues. The Board is the economic regulator charged with ongoing oversight of certain aspects of the regulated business of OPG and its prescribed facilities. The Payments Decision was the first opportunity for the Board to examine and consider the many issues associated with the setting of just and reasonable payment amounts for the prescribed facilities. The issues to be determined by the Board were complex, and the ambit of the decision was framed both by statute and by a regulation drafted in contemplation of the first payment amounts hearing. In this first payments case, it is self evident that the accurate assessment of the evidence would not only support the determination of the payment amounts for the test period but would also establish the framework for consistent results in future payment amounts proceedings.

---

[2] Submissions of SEC, paras. 3.1.1 – 3.2.2.

[3] Reply Submission, paras. 41 – 47. In support of its position, OPG cited Rules 1.03, 2.01, 2.02 and 5.01(a).

Given the significance of this first decision, and having considered the Motion and the written submission which accompanied it, the Board determined that an oral hearing on the threshold issue and the merits of the Motion was warranted in all of the circumstances; and that the breadth of its powers under the Rules, and its statutory mandate, permitted it to order such a hearing.

In making such a decision, the Board was exercising its authority, not relinquishing it. As it has done in the past and as it did in this instance, the Board will assess the circumstances of each matter in its determination of whether and how to proceed.

<u>The Motion</u>

The Motion sought a review and variance of the Payments Decision; an order for an oral hearing of the motion on the merits, or alternatively an oral hearing on the threshold question of whether the Motion raised a substantial question as to the correctness of the Decision[4]; and if successful, an order varying the Payments Decision, and establishing a variance account.

The Motion made specific reference to the Rules on which it relied in seeking such relief, and the written submission outlined the evidence, law and argument on which OPG based its request for a review on the merits and an order varying the Payments Decision.

The grounds for the Motion as set out in the Notice of Motion were:

1. the Board exceeded its jurisdiction by ordering a revenue requirement reduction of $342 million without evidentiary or legal foundation, unlawfully depriving OPG of the opportunity to recover its approved costs and return on equity;

[4] The Motion also stated that “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 Previous Motion was made”. As an oral hearing was ordered on both the merits of the motion and the threshold issues concurrently, this point was not argued; however, the Board points out that Rule 45 clearly states that it may dismiss a motion to review with or without a hearing. It is within the Board’s discretion to determine that the threshold has not been met, and to dismiss a motion to review without a hearing, based solely upon its review of the materials filed. No party seeking relief should expect the Board to grant its request; rather, the onus is on the moving party to persuade the Board to exercise its powers.

2. the Board 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
3. the Board's analysis and disposition of the regulatory tax loss and mitigation issue was never advanced at the hearing, depriving OPG of the opportunity to respond to the Board's approach to the regulatory tax loss and mitigation issue.

In the Notice of Motion the principal remedies sought were 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 the finding;

(iii) an order establishing a tax loss 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.[5]

In addition to the written submission, OPG filed a reply submission. At the hearing, it was noted by CME and SEC that the reply submission was the clearest expression of what was being sought by OPG, its arguments and the relief it was seeking. In particular, CME expressed frustration that its written submissions were superseded by the reply submission, and that due to its filing shortly before the oral hearing, limited time was available to consider and respond to certain aspects of the reply submission.

This Motion Record has been difficult to follow. The materials filed by OPG have evolved as between the Previous Motion and this Motion, from the filing of the written submission and the reply submission, and the oral argument. For example, the jurisdictional argument, which was one of three grounds in the Previous Motion and the first ground cited in the Motion, and to which a significant amount of the written

[5] OPG Compendium of Evidence, Tab 1, Notice of Motion, p. 1, para.2. Although expressed otherwise in the Notice of Motion, at the oral hearing OPG's counsel advised that the remedies were sought in the alternative: Hearing Transcript, pp. 9-11.

submission and the Brief of Authorities was devoted, was referred to as an alternative argument in the reply submission, and was characterized as OPG's 'fifth' argument at the oral hearing.[6]

A similar evolution occurred in the relief sought. In the Previous Motion OPG requested the establishment of a tax loss variance account that 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 re-calculation of the tax losses required by the Board in the Payments Decision.[7]

In the Motion, OPG requested the establishment of a variance account to record the revenue requirement reduction of $342 million incorporated in the test period payment amounts with the disposition of the account to be conducted in conjunction with the consideration of the analysis of prior period tax returns in OPG's next case.[8] In the reply submission, OPG explained the establishment of the variance account was to record the difference between the revenue requirement reduction of $342 million embedded in the test period payment amounts and the amount of regulatory tax losses recalculated in accordance with the Board's directions.[9]

While the Board appreciates that arguments and positions evolve in response to arguments posed by others, it reminds all parties that those who seek relief from the Board must ensure the clarity and consistency of the materials they file. This is fundamental to effective adjudication and informed decision making. It also encourages meaningful participation by all parties in the regulatory process.

FINDINGS

The Threshold Question

The Procedural and Substantive Issues related to the Threshold Question

[6] Reply submission, para. 79; Oral Hearing Transcript, pp. 25-28.

[7] OPG Compendium of Evidence, Tab 1, Previous Notice of Motion, p. 12.

[8] OPG Compendium of Evidence, Tab 1, Notice of Motion, p. 2.

[9] Reply submission, para. 34.

Rule 45.01 states that in respect of a motion to review brought under Rule 42.01, 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.

In determining the threshold question the Board considers the grounds for the motion, described in Rule 44.01 (a):

> 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:
>
> (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.

The list of grounds set out in Rule 44.01(a) is not exhaustive but rather illustrative.[10]

In the *Natural Gas Electricity Interface Review Decision* ("NGEIR Review Decision")[11] the Board determined that the threshold question requires the motion to review to meet the following tests:

- the grounds must raise a question as to the correctness of the order or decision;

- the issues raised that challenge the correctness of the order or decision must be such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended;

- there must be an identifiable error in the decision as a review is not an opportunity for a party to reargue the case;

- in demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made

[10] *Natural Gas Electricity Interface Review Decision*, May 22, 2007, EB-2006-0322/0338/0340. p.15.

[11] *Ibid.*

inconsistent findings, or something of a similar nature; it is not enough to argue that conflicting evidence should have been interpreted differently; and

- the alleged error must be material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.[12]

The Board's Finding on the Threshold Question

The Board is satisfied that the grounds put forward by OPG meet the tests as set out in the NGEIR Review Decision.

OPG has raised questions regarding the correctness of the finding that there was no connection between the mitigation offered by OPG and its regulatory tax losses, and the ordering of certain revenue requirement reductions after making that finding.

The Board is persuaded that those findings are inconsistent with the evidence; that those inconsistent findings are material and relevant to the outcome of the decision; and that if varied or changed, those findings would change the outcome of the decision.

The threshold having been met, the Board will proceed to consider the merits of the Motion.

<u>The Merits of the Revenue Requirement Reduction</u>

The Board must decide if the panel in the Payments Decision erred in

a) finding that OPG's proposal to eliminate an income tax provision in the test period was 'simply mitigation', and unrelated to regulatory tax losses;

b) finding that there was no connection between the tax loss benefits and OPG's proposed carry forward or acceleration of a revenue reduction of $228 million;

[12] *Supra*., pp. 17-18.

while also

c) ordering that OPG should not include any tax provision for 2008 and 2009 in respect of the prescribed assets; and

d) ordering that the amount of mitigation for the test period will be equal to 22% of the revenue deficiency calculated based on the Board's findings in the decision.

The reductions ordered were:

1. The elimination of any tax provision for the test year period in respect of the prescribed assets. In its findings, the Board did not provide an exact figure for this amount; in its materials, OPG calculated this amount to be $173 million.

2. Mitigation unrelated to regulatory tax losses in an amount equal to 22% of the revenue deficiency calculated based on the Board's findings in the Payment Decision; OPG calculated this amount to be $169 million.

If the Board now decides that the findings and the reductions are in error, then the Board must determine if the treatment of tax losses necessitates the establishment of a variance account.

OPG's Use of Tax Losses

In its application to determine payments for OPG's prescribed assets, OPG attributed the benefit of prior period tax losses to ratepayers. This was done in two parts. The first amount was to offset the 2008/2009 taxes calculated on regulatory assets. The second amount represented the remainder of the estimated prior period tax loss benefit which would normally be used to offset taxes in a future period. In its application and evidence, OPG recommended that this amount be moved forward to the 2008/2009 payment period to mitigate rateshock.

In its submissions in this hearing OPG indicated that it had always been its position that both amounts should be to the benefit of the ratepayers, since the calculated taxes were based on assets which OPG believed should receive regulatory treatment and would therefore impose costs on ratepayers. According to OPG, the only question of true mitigation was the availability of a portion of the benefit at an earlier period than would normally be the case.

Related Payment Decision Determinations

In the Payments Decision, the Board made several determinations which impact the calculation of taxes.

In its application OPG treated Bruce Nuclear revenues and costs as though they were related to a regulated business. The Board did not agree with this treatment. The Board required OPG to make these calculations on the basis of Generally Accepted Accounting Principles ("GAAP") and not regulatory accounting. The Board indicated that the treatment of taxes on Bruce revenues and costs should be treated in a normal GAAP manner and a tax provision should be included in the calculation of Bruce costs, contrary to OPG's proposal to carry forward tax loss benefits for the Bruce revenues and costs.

In its decision, the Board also made other findings questioning OPG's regulatory tax loss calculations. It observed that it did not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods, and ordered OPG to file better information and analysis on its forecast test period income tax provision in its next payment application. The Board stated that the analysis should be based on the principle that if electricity consumers should bear a cost (or should benefit from revenues) they should receive the related tax benefit (or will be charged the related income taxes).

Although these decisions on tax calculations are relevant to OPG's Motion, the findings have not been challenged by OPG or any other party. What the OPG Motion does challenge are the Board's findings which separate the rationale for the proposed revenue reduction from any tax loss benefit.

The Board found that OPG should reduce its revenue requirement by eliminating any tax provision for 2008 and 2009. The Board stated that because there was no evidence about the amount of the pre-2008 tax benefits that appropriately should be carried forward to offset 2008 and 2009 taxes, it viewed OPG's proposal to eliminate the test period's income tax provision as "simply mitigation."[13]

---

[13] Payments Decision, p. 171

In addition, the Board ordered OPG to reduce its revenue requirement by 22% of its revenue deficiency. This latter amount was calculated to be approximately the same percentage of revenue deficiency that OPG had proposed as an additional reduction. OPG had based its calculation on the amount of tax benefit that it expected to be available to future periods and which it proposed bringing forward to the test period; however, the Board also separated this reduction from tax loss benefits stating: "As for OPG's proposed $228 million mitigation amount, the Board does not accept that there is any connection between that amount and any regulatory tax losses."[14]

Positions taken on the Motion

OPG argued that the Board disposed of the regulatory tax loss and mitigation issue on a basis that was never raised or argued during the hearing, denying all parties the opportunity to make submissions on a material issue, and depriving the Board of the benefit of hearing parties on the issue. OPG submitted that by so doing, the Board was not fair and breached the rules of natural justice. PWU supported this argument in its written and oral submissions.

OPG also argued that the Board made findings that were unsupported by the evidence, thereby falling into error.

OPG argued:

> In OPG's submission, once the OEB decided that it was not satisfied there were any regulatory tax losses, or that they had not been correctly calculated, or that there was not sufficient evidence to determine the amount of those regulatory tax losses, the proper response was not to require OPG to proceed to reduce its revenue requirement by approximately $342 million in any event. Rather, the only proper and lawful course open to the OEB in the face of those findings involved one of two choices:
>
> 1. remove the mitigation proposal from any calculation of the revenue requirement for the test period and remit the matter for further consideration to a future panel; or
>
> 2. establish a variance account to record the revenue requirement reduction of $342 million embedded in the test period payment and consider the disposition of that

[14] Ibid.

> amount in the context of any regulatory tax loss calculations resulting from an analysis of prior period tax returns in OPG's next case.[15]

CME argued that any finding that was not based on evidence should be corrected. Assuming that the linkage between mitigation and the tax losses was restored, and a variance account was created as requested by OPG, the amount of the regulatory losses to be brought into the variance account should be corrected also; this correction could occur at the next payment amounts hearing when the tax loss analysis was placed into evidence, and tested by the intervenors and the Board.

SEC argued that as OPG's proposed revenue reduction was entirely voluntary, it should be required to live with the consequences of its own proposal. In support of its characterization of the proposed reduction as voluntary, SEC cited a portion of the transcript of the original hearing where Mr. Barrett of OPG describes returning the tax loss benefit to the ratepayers in the following way, "Yes, we do not believe this treatment is required, but we do believe that it is appropriate".[16] Therefore, SEC argued, the Board gave OPG what it asked for and the company should not be able to overturn the decision now because the tax calculations modified by the Board's decision result in a significantly lower regulatory tax benefit than OPG anticipated.

OPG and SEC both stated that the issue of the tax calculations was not raised in the hearing. SEC pointed out that while intervenors may have questioned the Board's decision in regard to those calculations, they could not move for review since the Board maintained the approximate revenue reduction as proposed originally by OPG.

Board Findings and Disposition of the Motion to Review

OPG and PWU argued that the Board disposed of the regulatory tax loss and mitigation issue on a basis that was never raised or argued during the hearing, depriving parties of the opportunity to make submissions; by doing so, it was alleged that the Board denied OPG procedural fairness and breached the rules of natural justice.

While being provided the opportunity to make submissions is desirable, there is no general rule precluding the Board, a specialized economic energy regulator, from

[15] OPG Written Submission, para. 53.

[16] OPG Compendium of Evidence, Tab 4, Hearing Day 15, June 20, 2008, p. 75, ls. 20-21.

reaching decisions based on its own analysis of the record or on its own expertise or on the basis of some combination of the two. Ultimately the determination of whether fairness is breached in particular circumstances turns on the circumstances. In this case, the Board finds it unnecessary to make a specific finding on this issue.

The Board finds that the evidentiary record established and supported a link between the regulatory tax losses and the revenue requirement reduction. The oral and written evidence provided by OPG consistently linked the tax losses with the revenue requirement reduction. That evidence was not challenged by any party.

If a reviewing panel is satisfied that an identifiable error that is material and relevant to the outcome of the reviewed decision has been made, the Board may vary, suspend or cancel the order or decision, or if they find it appropriate, remit the matter back to the original panel.[17] As noted above, the Board has determined that identifiable errors that are material and relevant to the outcome of the reviewed decision have been made.

The Board varies the Payments Decision in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the 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 Payments Decision as to the re-calculation of those tax losses.

The clearance of this account will be reviewed in OPG's next payment application hearing when a future panel of the Board reviews the tax analysis ordered in the Payments Decision.[18] The Board anticipates that any issues related to tax calculations will be dealt with at the next payment amounts hearing.

---

[17] *A Review of Certain Parts of the Natural Gas Electricity Interface Review Decision of November 7, 2006 and Conducted Pursuant to the Board's Review Decision of May 22, 2007*, EB-2006-0322/-340, Decision with Reasons, July 30, 2007, p. 1.

[18] Payments Decision, p. 171: "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).

Costs

A decision regarding cost awards will be issued at a later date. Eligible intervenors claiming costs should do so as ordered below. OPG shall pay any Board costs of and incidental to this proceeding upon receipt of the Board's invoice.

THE BOARD THEREFORE ORDERS THAT

1. The Payments Decision shall be varied in a manner that links the revenue requirement reduction and the regulatory tax losses;

2. OPG shall establish a variance account to be called the Tax Loss Variance Account to be effective as of April 1, 2008;

3. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims within 14 days from the date of this Decision;

4. OPG may file with the Board and forward these intervenors any objections to the claimed costs within 28 days from the date of this Decision;

5. Intervenors, whose cost claims have been objected to, may file with the Board and forward to OPG any responses to any objections for cost claims within 35 days of the date of this Decision; and

6. Filings are to be in the form of two hardcopies and one electronic copy in searchable PDF format at boardsec@oeb.gov.on.ca and copy Ontario Power Generation Inc.

ISSUED at Toronto, May 11, 2009
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

EB-2009-0174

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 the generating facilities.

BEFORE: Cynthia Chaplin
Presiding Member

DECISION AND ORDER

The Application

Ontario Power Generation Inc. ("OPG") filed an application for an accounting order with the Ontario Energy Board (the "Board") on June 9, 2009, under section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15 (Schedule B). The Board assigned the application File No. EB-2009-0174.

On November 3, 2008, the Board issued its Decision with Reasons in OPG's payment amounts proceeding (EB-2007-0905) (the "payment amounts decision") which, among other things, approved certain variance and deferral accounts. On December 2, 2008, the Board issued a payment amounts order which described the treatment of approved variance and deferral accounts for a 21 month period ending December 31, 2009. The current application notes that OPG has deferred the filing of its next payment amounts application by one year and will apply for new payment amounts effective January 1, 2011. OPG states that it requires an accounting order to address the treatment of deferral and variance accounts beginning on January 1, 2010. OPG seeks an order approving:

- the continuation of the amortization of the previously approved balances in certain nuclear deferral and variance accounts;
- the continuation of nuclear payment rider A;
- the establishment of a nuclear variance and deferral over/under recovery variance account; and
- the basis for recording entries in approved deferral and variance accounts after December 31, 2009.

The Proceeding

On June 30, 2009, a Notice of Hearing and Procedural Order No. 1 was issued. The Board adopted as intervenors in this proceeding the intervenors and parties of record from the payment amounts proceeding. No other parties sought intervenor or observer status.

The Notice of Hearing and Procedural Order No.1 made provision for interrogatories, responses and submissions. In response to the procedural order, the Canadian Manufacturers & Exporters ("CME") requested that a technical conference be scheduled following delivery of the interrogatory responses. The request was supported by Energy Probe Research Foundation ("Energy Probe") and the School Energy Coalition ("SEC"). OPG responded on July 13, 2009 that the request was premature. In correspondence from the Board, parties were advised that the Board would determine whether further discovery, in the form of a technical conference or additional interrogatories, was required following the filing of responses. Board staff, CME and SEC filed interrogatories on July 24, 2009 and OPG filed responses on August 7, 2009. Certain of the interrogatories requested that OPG provide transactions and balances for the deferral and variance accounts. On August 17 and September 1, 2009, OPG filed updates to the transactions and balances for several nuclear variance accounts.

The Relevance of OPG's Next Payment Amounts Application to this Accounting Order

CME Interrogatory #1 ("CME IR#1") focused on OPG's decision not to file an application for new payment amounts effective January 1, 2010, and sought information on the "circumstances which prompted the decision, including the extent to which the current payment amounts are estimated by OPG to be capable of supporting its estimated Hydroelectric and Nuclear Revenue Requirements for the 2010 calendar year " OPG's response, filed on August 7, 2009, stated that CME IR#1 was not relevant to the accounting order application and that the information was not required to resolve the current application.

On August 10, 2009, CME requested that the Board direct OPG to provide a response to CME IR#1. CME submitted that the information requested was relevant to a determination of whether any ratepayer protection conditions should be attached to the accounting order relief sought by OPG, namely an asymmetric Earnings Sharing Mechanism. SEC supported CME's request stating that a response to CME IR#1 may end up answering any questions that may arise about the fairness of continuing existing payment amounts and protections. Energy Probe submitted that an oral hearing was required to canvass the issues brought forward by CME.

OPG responded on August 12, 2009, and submitted that the accounting order application is narrow and deals almost exclusively with deferral and variance accounts already approved by the Board. OPG referred to the Board's payment amounts decision, noting that the establishment of deferral and variance accounts was not related to revenue requirement, whereas CME IR#1 is almost entirely related to the 2010 revenue requirement.

On August 17, 2009, CME filed correspondence quoting the news release for OPG's 2009 Second Quarter Financial Results. CME stated that the net income impacts are a strong indicator that OPG is probably forecasting a significant revenue sufficiency for 2010. CME submitted that the financial results supported its request that the Board direct OPG to respond to CME IR#1.

In correspondence from the Board on August 18, 2009, parties were advised that the Board would not require OPG to answer CME IR#1 as the current proceeding is concerned with ongoing implementation of Board determinations relating to deferral and variance accounts and is not an examination of 2010 revenue requirement. The Board stated that the current payments amounts would remain in place until OPG files an application to change the payment amounts or as a result of the Board initiating a proceeding on its own motion to determine whether the payment amounts remain just and reasonable. The Board indicated that the process established in Procedural Order No. 1 would remain in place.

Accordingly, Board staff, CME, SEC and Energy Probe filed submissions on August 21, 2009 and OPG filed a reply argument on September 4, 2009.

The Recovery of Hydroelectric Variance Account Balances as Part of the Hydroelectric Payment Amount

The payment amounts decision approved recovery of $13.4 M related to two hydroelectric variance accounts. The approved recovery, which was included in the hydroelectric payment amount, ends on December 31, 2009. Board staff submitted that there will be over recovery related to these balances between January 1, 2010 and December 31, 2010. Board staff submitted that it would be appropriate to track the over collection of approximately $8 M in a variance account for the purposes of future disposition. The submission was supported by Energy Probe. In its submission, OPG stated that it had no objection to separate tracking of any over/under recovery.

Board Findings

The Board finds that it is appropriate to correct for any over-recovery of the Hydroelectric Variance Account balances and notes that OPG is not opposed to this approach. The Board approves the establishment of a variance account to record the over collection of hydroelectric variance account balances that are recovered through the hydroelectric payment amount. The approved account “Hydroelectric Deferral and Variance Over/Under Recovery Variance Account” will be used to record the over/under recoveries commencing on January 1, 2010.

Treatment of Deferral and Variance Accounts after December 31, 2009

There were no submissions from parties explicitly related to continued amortization of the balances in the deferral and variance accounts, continuation of nuclear payment rider A, establishment of a nuclear variance and deferral over/under recovery variance account, or the basis for recording entries in approved deferral and variance accounts after December 31, 2009. Submissions from intervenors were concerned primarily with the status of OPG’s current payment amounts during 2010. These submissions are addressed in the final section of this decision.

The payment amounts decision approved recovery of December 31, 2007 balances for seven deferral and variance accounts, with recovery periods of two, three or four years.

The hydroelectric variance account balances with two year recovery periods have already addressed in this decision. The payment amounts decision approved recovery of the account balances in the five other accounts through nuclear payment rider A. Appendix F of the payment amounts order states that nuclear payment rider A shall apply "to OPG's nuclear production for the period December 1, 2008 to December 31, 2009". OPG proposed the continuation of nuclear payment rider A beyond December 31, 2009, and the continued amortization and recovery of the approved December 31, 2007 balances in the following accounts:

- Ancillary Services Net Revenue Variance Account – Nuclear;
- Transmission Outages and Restrictions Variance Account;
- Pickering A Return to Service Variance Account;
- Nuclear Liability Deferral Account; and
- Nuclear Development Deferral Account, Transition.

OPG also requested a new account, a nuclear variance and deferral over/under recovery variance account, to capture the difference between forecast and actual production during the test period relating to nuclear payment rider A and rider C. OPG stated that the new account is in principle the same as the two other shortfall accounts the Board approved in the payments amounts decision. OPG explained that the account was not requested as part of the payment amounts application due to an oversight.

Board Findings

The Board finds that it is appropriate to continue to recover the approved balances over the approved recovery periods and to do so through the continuation of nuclear payment rider A. The Board approves the continuation of nuclear payment rider A, and the continued amortization and recovery of the approved December 31, 2007 balances in the following accounts:

- Ancillary Services Net Revenue Variance Account – Nuclear;
- Transmission Outages and Restrictions Variance Account;
- Pickering A Return to Service Variance Account;
- Nuclear Liability Deferral Account; and
- Nuclear Development Deferral Account, Transition.

The Board also approves the request for a new variance and deferral over/under recovery variance account. The approved account is entitled “Nuclear Deferral and Variance Over/Under Recovery Variance Account”.

The Basis for Recording Entries in Approved Accounts

The entries for the approved deferral and variance accounts are based on comparing actual costs or revenues to forecasts, with the exception of the Bruce Lease Net Revenues Variance Account. As a consequence of OPG deferring the filing of its next payment amounts application, OPG proposed, in the subject application, to use forecasts derived from 2008 and 2009 forecast values for the period after December 31, 2009 for the following accounts:

- Hydroelectric Ancillary Service Net Revenue Variance Account;
- Nuclear Ancillary Service Net Revenue Variance Account;
- Nuclear Development Variance Account; and
- Capacity Refurbishment Variance Account.

For the following accounts, OPG proposed specific treatment based on the same principles as used for the accounts listed above, namely applying the forecasts or methodologies underlying the current payment amounts:

- Hydroelectric Water Conditions Variance Account;
- Nuclear Liability Deferral Account;
- Nuclear Fuel Cost Variance Account; and
- Income and Other Taxes Variance Account.

The Bruce Lease Net Revenues Variance Account records the difference between the forecast costs and revenues related to the Bruce lease that are factored into the nuclear payment amounts and OPG’s actual revenues and costs. For the period after December 31, 2009, OPG proposed to measure the variance by comparing the actual Bruce lease net revenues credited to customers monthly through the current payment amounts to the actual net revenues realized by OPG on a GAAP basis. OPG proposed that the actual net revenues credited to consumers continue at the same rate of recovery approved for the 21 month test period in the payment amounts decision.

Board Findings

The Board finds that the proposed treatment is acceptable. In each case, the entries will be derived using the same underlying forecasts and methodologies as were used to set the current payment amounts.

The Status of OPG's Current Payment Amounts

CME submitted that based on OPG's 2009 second quarter financial results, "OPG may now be forecasting significant revenue sufficiencies for 2009 and 2010." In CME's view, OPG should, as a condition of the approval of this application, be obliged to account to its ratepayers in its next payments proceeding for the extent to which its 2010 earnings materially exceed the Board approved rate of return. CME noted that in prior proceedings involving gas utilities, the Board has imposed asymmetric obligations on utilities to account for possible over earnings. CME requested that a similar type of ratepayer safeguard order be made in this case.

SEC submitted that if the Board approves the application it is in effect approving the continuation of the existing payment amounts and indirectly providing a final determination regarding 2010 payment amounts. SEC submitted that the Board should grant the relief requested by OPG in this application, but declare the payment amounts to be interim commencing January 1, 2010.

In its response, OPG stated that the CME and SEC arguments were addressed by the Board's letter of August 18, 2009, and the purpose of the current application was to seek clarity on the technical application of the payment amounts order.

OPG noted that CME's reference to OPG's second quarter financial results compares 2009 results with 2008 and therefore cannot be used to assess whether OPG's 2009 earnings are above the Board approved level. OPG stated that the favourable impact on net income reported in the news release was a result of OPG's implementation of Board decisions on the tax loss variance account and the nuclear funds.

OPG reviewed the gas utility decision referred to by CME. In OPG's opinion, the earnings sharing mechanism implemented by the Board in that decision was due to a regulatory lag problem, a circumstance which does not arise in the current application

Board Findings

The scope of the current proceeding does not include an examination of OPG's earnings in 2009 or 2010, and, therefore, the Board finds there is no reason to order an asymmetric earnings sharing mechanism as a condition of the Board's approval of this application. The case involving Enbridge Gas Distribution Inc., identified by CME, involved a general rates application that was abbreviated in nature in order to address regulatory lag. The Board finds that the circumstances in that case are in no way comparable to the current proceeding.

SEC has argued that if the Board approves the application it is indirectly providing a final determination regarding 2010 payment amounts. The Board does not agree. This proceeding is not an enquiry into OPG's 2010 revenue requirement. The Board's approval of this application does not preclude OPG from making an application later for new payments amounts for 2010; nor does it preclude the Board from initiating a proceeding on its own motion to determine payment amounts for 2010. It would only be in the context of either of those events that an order making OPG's payment amounts interim as of January 1, 2010, would be appropriate.

THE BOARD ORDERS THAT:

1. OPG shall establish a variance account to be named the Hydroelectric Deferral and Variance Over/Under Recovery Variance account to be effective as of January 1, 2010;

2. OPG shall continue nuclear payment rider A beyond December 31, 2009, and the continued amortization and recovery of the approved December 31, 2007 balances in the following accounts:

    - Ancillary Services Net Revenue Variance Account – Nuclear;
    - Transmission Outages and Restrictions Variance Account;
    - Pickering A Return to Service Variance Account;
    - Nuclear Liability Deferral Account; and
    - Nuclear Development Deferral Account, Transition;

3. OPG shall establish a variance account to be named the Nuclear Deferral and Variance Over/Under Recovery Variance account to be effective as of April 1, 2008;

4. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims within 14 days of the date of this Decision;

5. OPG may file objections within 28 days of the date of this Decision. A copy of the objection must be filed with the Board and a copy must be forwarded to the party against whose claim the objection is being made;

6. Intervenors whose cost claims have been objected to may file with the Board and forward to OPG any responses to any objections for cost claims within 35 days of the date of this Decision; and

7. All filings to the Board must quote file number EB-2009-0174, be made through the Board's web portal at www.errr.oeb.gov.on.ca , and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca . If the web portal is not available you may email your document to the address below. Those who do not have internet access are required to submit all filings on a CD or diskette in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies. All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ISSUED at Toronto, October 6, 2009

ONTARIO ENERGY BOARD

Original signed by

John Pickernell
Assistant Board Secretary

Table 1
Summary of Regulated Hydroelectric Revenue Requirement ($M)

Line No.	Description	Note	April 1 to December 31, 2008 OPG Proposed	Board Adjust	Board Approved	January 1 to December 31, 2009 OPG Proposed	Board Adjust	Board Approved	Total OPG Proposed	Board Adjust	Board Approved
			(a) Note 1	(b)	(c)	(d) Note 1	(e)	(f)	(g) Note 1	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**		3,857.8	0.0	3,857.8	3,847.5	0.0	3,847.5	N/A	N/A	N/A
2	**Working Capital**		0.6	0.0	0.6	0.6	0.0	0.6	N/A	N/A	N/A
3	**Cash Working Capital**		21.8	0.0	21.8	21.8	0.0	21.8	N/A	N/A	N/A
4	**Total Rate Base**		3,880.2	0.0	3,880.2	3,869.9	0.0	3,869.9	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	99.4	16.7	116.1	99.6	15.9	115.5	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,549.7	390.8	1,940.5	1,545.0	390.4	1,935.5	N/A	N/A	N/A
7	**Common Equity**	2	2,231.1	(407.4)	1,823.7	2,225.2	(406.3)	1,818.8	N/A	N/A	N/A
8	**Nuclear Liabilities**	2	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A	N/A
9	**Total Capital**		3,880.2	(0.0)	3,880.2	3,869.9	(0.0)	3,869.9	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	5.8	0.9	6.7	6.0	0.9	6.9	11.8	1.9	13.6
11	**Long-Term Debt**	3	65.4	17.8	83.2	91.5	22.5	113.9	156.9	40.3	197.1
12	**Return on Equity**	3	175.7	(57.4)	118.3	233.6	(76.3)	157.3	409.3	(133.7)	275.7
13	**Nuclear Liabilities**	3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Cost of Capital**		246.9	(38.6)	208.3	331.1	(52.9)	278.2	578.0	(91.5)	486.4
	Expenses										
15	**OM&A**		93.1	0.0	93.1	119.0	0.0	119.0	212.1	0.0	212.1
16	**Fuel and GRC**		179.9	0.0	179.9	244.1	0.0	244.1	424.0	0.0	424.0
17	**Depreciation & Amortization**	4	45.9	6.9	52.8	61.6	9.3	70.9	107.5	16.2	123.7
18	**Property and Capital Taxes**		6.5	0.0	6.5	8.7	0.0	8.7	15.2	0.0	15.2
19	**Total Expenses**		325.4	6.9	332.3	433.3	9.3	442.6	758.7	16.2	774.9
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		N/A		N/A	N/A		N/A	N/A	0.0	N/A
21	**Ancillary and Other Revenue**	5	24.3	10.1	34.4	33.1	13.5	46.6	57.4	23.6	81.0
22	**Total Other Revenues**		24.3	10.1	34.4	33.1	13.5	46.6	57.4	23.6	81.0
23	**Income Tax**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Revenue Requirement before Mitigation**		548.0	(41.8)	506.2	731.3	(57.1)	674.2	1,279.3	(98.9)	1,180.4

For notes see Table 1a.

Table 1a
Notes to Table 1
Summary of Regulated Hydroelectric Revenue Requirement ($M)

Notes:

1 Agrees to Exhibit K1-T1-S1 Tables 1 and 2 - Summary of Revenue Requirement for April to December of 2008, and January 1, 2009 to December 31, 2009.

2 Capitalization for OPG's combined regulated operations is provided in Payment Amounts Order App A Table 4 for April 1 to December 31, 2008 and Payment Amounts Order App A Table 5 for January 1, 2009 to December 31, 2009. The Board determined that a portion of OPG's rate base will earn a return limited to the average accretion rate on OPG's nuclear liabilities. Payment Amounts Order App A Tables 4 and 5 identify that portion of rate base. The remaining rate base is financed with 53% debt and 47% equity as determined by the Board. The impact on capital structure is provided in Payment Amounts Order App A Tables 4 and 5. These resulting capital structure amounts are allocated to regulated hydroelectric and nuclear based on their relative rate base amounts. OPG has directly assigned the portion of rate base financed at the average accretion rate to its nuclear operations; therefore the allocation of the remaining capital structure components must be revised to reflect the change in the nuclear rate base:

			Apr to Dec 2008	2009
Approved reg. hydroelectric rate base	(a)	App A Table 1 Line 4	3,880.2	3,869.9
Approved nuclear rate base	(b)	App A Table 2 Line 4	3,509.1	3,483.8
Financing directly assigned to nuclear rate base	(c)	App A Table 2 Line 8	(1,060.3)	(1,012.9)
Nuclear rate base financed by capital structure	(d) = (b) - (c)		2,448.8	2,470.9
Reg. hydroelectric allocation	(e) = (a) / ((a) + (d))		61.31%	61.03%
Nuclear allocation	(f) = (d) / ((a) + (d))		38.69%	38.97%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order App A Tables 4 and 5. The cost of capital is allocated between regulated hydroelectric and nuclear operations consistent with the capital structure allocation described in Note 2 above.

4	**Description of Adjustment to Amortization Expense**	**Apr to Dec 2008**	**2009**	**Total**
	Remove revenue sharing from SMO transactions prior to OEB regulation in accordance with OEB Decision	6.9	9.3	16.2

5	**Description of Adjustment to Other Revenues**	**Apr to Dec 2008**	**2009**	**Total**
	Inclusion of SMO revenues for test period per OEB Decision	4.9	6.6	11.5
	Inclusion of Water Transfer revenues for test period per OEB Decision	5.2	6.9	12.1
	Total OM&A Adjustments	10.1	13.5	23.6

Table 2
Summary of Nuclear Revenue Requirement ($M)

Line No.	Description	Note	April 1 to December 31, 2008 OPG Proposed	Board Adjust	Board Approved	January 1 to December 31, 2009 OPG Proposed	Board Adjust	Board Approved	Total OPG Proposed	Board Adjust	Board Approved
			(a) Note 1	(b)	(c)	(d) Note 1	(e)	(f)	(g) Note 1	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**		2,787.7	0.0	2,787.7	2,696.0	0.0	2,696.0	N/A	N/A	N/A
2	**Working Capital**		705.4	0.0	705.4	771.8	0.0	771.8	N/A	N/A	N/A
3	**Cash Working Capital**		16.0	0.0	16.0	16.0	0.0	16.0	N/A	N/A	N/A
4	**Total Rate Base**		3,509.1	0.0	3,509.1	3,483.8	0.0	3,483.8	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	89.9	(16.7)	73.2	89.7	(15.9)	73.8	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,401.4	(176.8)	1,224.6	1,390.9	(155.1)	1,235.8	N/A	N/A	N/A
7	**Common Equity**	2	2,017.7	(866.8)	1,150.9	2,003.2	(841.9)	1,161.4	N/A	N/A	N/A
8	**Nuclear Liabilities**	2	0.0	1,060.3	1,060.3	0.0	1,012.9	1,012.9	N/A	N/A	N/A
9	**Total Capital**		3,509.1	(0.0)	3,509.1	3,483.8	0.0	3,483.8	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	5.2	(0.9)	4.3	5.4	(1.0)	4.4	10.6	(1.9)	8.7
11	**Long-Term Debt**	3	59.2	(6.7)	52.5	82.4	(9.6)	72.8	141.6	(16.3)	125.3
12	**Return on Equity**	3	158.9	(84.2)	74.7	210.3	(109.9)	100.5	369.2	(194.1)	175.1
13	**Nuclear Liabilities**	3	0.0	44.5	44.5	0.0	56.7	56.7	0.0	101.2	101.2
14	**Total Cost of Capital**		223.3	(47.4)	175.9	298.1	(63.7)	234.3	521.4	(111.1)	410.3
	Expenses										
15	**OM&A**	4	1,662.7	(15.9)	1,646.8	2,168.7	(21.4)	2,147.3	3,831.4	(37.3)	3,794.1
16	**Fuel and GRC**		125.7	0.0	125.7	204.2	0.0	204.2	329.9	0.0	329.9
17	**Depreciation & Amortization**	5	277.2	19.6	296.8	388.9	26.4	415.3	666.1	46.0	712.1
18	**Property and Capital Taxes**		16.3	0.0	16.3	22.0	0.0	22.0	38.3	0.0	38.3
19	**Total Expenses**		2,082.0	3.7	2,085.7	2,783.8	5.0	2,788.8	4,865.8	8.7	4,874.5
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**	6	51.8	28.2	80.0	82.6	29.3	111.9	134.4	57.5	191.9
21	**Ancillary and Other Revenue**		49.4	0.0	49.4	50.9	0.0	50.9	100.3	0.0	100.3
22	**Total Other Revenues**		101.2	28.2	129.4	133.4	29.3	162.7	234.6	57.5	292.1
23	**Income Tax**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Revenue Requirement before Mitigation**		2,204.1	(71.8)	2,132.3	2,948.4	(88.0)	2,860.4	5,152.5	(159.9)	4,992.6

For notes see Table 2a.

Table 2a
Notes to Table 2
Summary of Nuclear Revenue Requirement ($M)

Notes:

1 Agrees to Exhibit K1-T1-S1 Tables 1 and 2 - Summary of Revenue Requirement for April to December of 2008, and January 1, 2009 to December 31, 2009.

2 Capitalization for OPG's combined regulated operations is provided in Payment Amounts Order App A Table 4 for April 1 to December 31, 2008 and Payment Amounts Order App A Table 5 for January 1, 2009 to December 31, 2009. The capital structure is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order App A Table 1a, Note 2. The resulting allocation ratios for nuclear operations are:

Nuclear allocation for April 1, 2008 to December 31, 2008 is:	38.69%
Nuclear allocation for January 1, 2009 to December 31, 2009 is:	38.97%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order App A Tables 4 and 5. The cost of capital is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order App A Table 1a, Note 2

4 **Description of Adjustment to OM&A Expense**

	Apr to Dec 2008	2009	Total
Pickering A reduction of 10% to base OM&A budget	(14.9)	(20.1)	(35.0)
Nuclear advertising	(1.0)	(1.3)	(2.3)
Total Adjustment	(15.9)	(21.4)	(37.3)

5 **Description of Adjustment to Amortization Expense**

	Apr to Dec 2008	2009	Total
Reduced PARTS recovery period (Payment Amounts Order App D, Line 1 column (f) - (c))	24.0	32.4	56.4
Remove test period amortization of Pickering B refurbishment costs incurred prior to OEB regulation (Test period amortization = ($16.2M total recovery amount per OEB Decision x 33 month proposed amortization period) / 21 month test period)	(4.4)	(6.0)	(10.4)
Total Adjustment	19.6	26.4	46.0

6 See Payment Amounts Order App A Table 7 for details of the adjustment.

Table 3
Summary of Approved Revenue Deficiency by Technology ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Regulated Hydroelectric 2008 (Apr 1-Dec 31)	Regulated Hydroelectric 2009 Jan 1-Dec 31)	Regulated Hydroelectric Total	Nuclear 2008 (Apr 1-Dec 31)	Nuclear 2009 Jan 1-Dec 31)	Nuclear Total	Total Test Period
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Forecast Production (TWh)**[1]	12.9	18.5	31.5	38.3	49.9	88.2	N/A
2	**Prescribed Payment Amount ($/MWh)**[1]	33.0	33.0	33.0	49.5	49.5	49.5	N/A
3	**Indicated Production Revenue ($M)**[1]	427.1	611.1	1,038.1	1,897.7	2,470.2	4,367.9	5,406.0
	(line 1 * line 2)							
4	**Approved Revenue Requirement Before Mitigation ($M)**[2]	506.2	674.2	1,180.4	2,132.3	2,860.4	4,992.6	6,173.0
5	**Revenue Deficiency Before Mitigation ($M)**	79.1	63.1	142.2	234.6	390.2	624.7	767.0
	(line 4 - line 3)							
6	**Mitigation Prescribed By OEB: 22% of Revenue Deficiency**[3]	11.6	15.4	27.0	60.7	81.0	141.7	168.6
7	**Revenue Deficiency After Mitigation ($M)**	67.5	47.7	115.2	173.9	309.2	483.0	598.4
	(line 5 - line 6)							
8	**Revenue Requirement Reflected In Approved Payment Amounts**							
	(line 4 - line 6)	494.6	658.8	1,153.4	2,071.6	2,779.4	4,850.9	6,004.4

Notes:
1 EB-2007-0905 Ex. A1-T3-S1 Table 3
2 From Payment Amounts Order App A Table 1 (Reg. Hydro) and Payment Amounts Order App A Table 2 (Nuclear)
3 Mitigation determined as 22% of total revenue deficiency allocated to equalize payment amount increase between Nuclear and Regulated Hydroelectric:

	Reg. Hydro	Nuclear	Total
	27.0	141.7	168.6
2008 Portion: 9 months / 21 months	11.6	60.7	72.3
2009 Portion: 12 months / 21 months	15.4	81.0	96.4
Total Allocated by Technology	27.0	141.7	168.7

Table 1
Test Period Revenue Deficiency at Approved Payment Amounts[1,2] ($M)

Line No.	Item	Notes	Nuclear	Regulated Hydroelectric	Total Regulated Facilities
	Revenues				
1	Payment Amount ($/MWh)	3	54.98	36.66	N/A
2	Forecast Energy (TWh)		88.2	31.5	119.7
3	Energy Revenue (line 1 x line 2)		4849	1155	6004
4	Other Revenues		292	81	373
5	Total Revenues		5141	1236	6377
	Costs				
6	OM&A		3794	212	4006
7	Fuel & GRC		330	424	754
8	Depreciation & Amortization		712	124	836
9	Property & Capital Taxes		38	15	54
10	Financing Costs	4	235	211	446
11	Income Taxes	5	N/A	N/A	66
12	Total Costs		N/A	N/A	6161
13	**Net Income**		N/A	N/A	**216**
	(line 5 - line 12)				
14	Average Equity	6			2978
15	**ROE at Approved Payment Amounts**				**4.1%**
	((line 13 x 12/21) / line 14)				
	DEFICIENCY CALCULATION:				
16	Test Period Net Income at 8.65% ROE				451
	(line 14 x 8.65% x 21/12)				
17	Deficiency Before Gross-up for Taxes				235
	(line 16 - line 13)				
18	Add Gross-up for Tax on Deficiency	7			107
	((line 17 / (1-31.21%)) - line 17)				
19	**Revenue Deficiency to Achieve 8.65% ROE**				**342**
	(line 17 + line 18)				
	Components of Deficiency Required by the OEB				
20	Foregone Tax Provision (line 11 + line 18)				173
21	Additional Mitigation	8			169
22	Total (line 20 + line 21)				**342**

N/A - Not Applicable

Notes:
1 All information is for the 21-month test period, April 1, 2008 - December 31, 2009.
2 All values from EB-2007-0905 Final Payment Order ("Final Order"), Dec. 2, 2008 unless otherwise noted.
3 Nuclear payment amount includes $2.00/MWh nuclear variance and deferral account payment rider A.
4 Financing costs include long-term debt, short-term debt and financing for nuclear liabilities.
5 Income tax expense calculated using approved payment amounts.
6 Average Equity is calculated as follows:

	Apr-Dec 2008	2009	Average Test Period Equity
Approved regulated hydroelectric rate base	3880	3870	
Equity at approved equity ratio of 47%	1824	1819	
Test period average - regulated hydroelectric			1821
Approved nuclear rate base	3509	3484	
Average unfunded nuclear liability	1060	1013	
Rate base less average unfunded nuclear liability	2449	2471	
Equity at approved equity ratio of 47%	1151	1161	
Test period average - nuclear			1157
Total Regulated Facilities			2978

7 Tax rate of 31.21% is the weighted average of 2008 and 2009 tax rates.
8 See Final Order, Appendix A, Table 3.

TORYS LLP

Suite 3000
79 Wellington St. W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada
Tel 416.865.0040
Fax 416.865.7380

www.torys.com

August 12, 2009

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27thFloor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2009-0174

I am counsel to Ontario Power Generation Inc., the applicant in this matter. This letter responds, in accordance with the direction of the OEB in Ms. Binette's email of August 10, 2009, to submissions from CME, SEC and Energy Probe on the question of further discovery in this proceeding.

The Issue

The issue engaged by intervenor submissions is a narrow one. There is no longer, as there was in July, any generic request for a technical conference. The sole issue engaged by the intervenor submissions is whether CME interrogatory #1 is relevant to this proceeding and should be answered. The question of the potential for further discovery or the need for a technical conference now only arises if this question is answered affirmatively.

The threshold question then, is a question of relevance: is CME interrogatory #1 relevant to this application? In OPG's submission, it is not.

OPG's Application

It is important to note that this Application is not, as some intervenors seem to suggest, an application to continue OPG's approved variance and deferral accounts. OEB approval is not required for these accounts to continue past December 31, 2009. This is because nothing in the OEB's Decision of November 3, 2008 or the Payments Amounts Order of December 2, 2008 imposes any end date for the operation of these accounts. The result is they continue until terminated by order of the OEB.

OPG's Application is very specific about this. The only issue with respect to the:

- Ancillary Services Net Revenue Variance Account - Nuclear
- Transmission Outages and Restrictions Variance Account

- Pickering A Return to Service Deferral Account
- Nuclear Liability Deferral Account
- Nuclear Development Deferral Account, Transition

accounts is the "continued amortization of the OEB approved balances." The Decision approves amortization periods for these accounts of December 31, 2011, in the case of the PARTS account, and December 31, 2010 in the case of the rest. The Decision established the Nuclear Payment Rider (Rider A) of $2.00/MWh on that basis. The only clarification sought in the Application is that the Payments Amounts Order (perhaps erroneously or through oversight), in Appendix F, p. 2, authorized Rider A "for the period December 1, 2008 to December 3, 2009." OPG therefore is merely seeking to continue the rider and amortization amounts already approved by the Board on the basis that the OEB has already specifically decided.

As noted in OPG's Application, at p. 4, "all of the nuclear variance and deferral accounts established by O. Reg. 53/05 have approved recovery periods ending December 31, 2010, with the exception of the Pickering A Return to Service ("PARTS") Deferral Account [which has recovery period ending December 31, 2011]." This is money, therefore, that the OEB has already held OPG is entitled to.

It is also important to note in this connection that a number of OPG's accounts are required by O. Reg. 53/05 and that recovery of these accounts is also required in accordance with specified terms and conditions (see Decision, p. 122).

The other main purpose of OPG's Application is to clarify "the basis for recording entries" in the following accounts:

- Hydroelectric Water Conditions Account
- Ancillary Services Net Revenue Variance Account - Hydroelectric
- Ancillary Services Net Revenue Variance Account - Nuclear
- Pickering A Return to Service Deferral Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Capacity Refurbishment Variance Account
- Nuclear Fuel Cost Variance Account
- Income and Other Taxes Variance Account
- Bruce Lease Net Revenues Variance Account.

The need for this clarification arose because the Decision (and Payment Amounts Order) only specified the basis for recording entries during the test period. In all cases, however, OPG is proposing no change to the status quo respecting the methodology used to record entries in these accounts. The OEB-approved forecast from the Decision will continue to be the basis for these entries.

The only other issue raised by OPG's Application is a request to establish an account to capture any under or over-recoveries resulting from nuclear payment Rider A and C. This was an uncontroversial provision that was overlooked at the time of OPG's payment amounts case.

OPG's Application proposes no rate change and seeks no approvals regarding disposition of account balances. All these issues are preserved, without prejudice to all rights of review in the ordinary course, for a future hearing on the merits.

The Intervenor Argument

CME interrogatory #1 is a two page multi part question. It concerns a request for a large amount of cost of service-type information, not only 2010 forecast revenue requirement but also 2008/2009 actual performance against OEB-approved forecasts. There is also a broad, "fishing expedition" style question seeking to explore the reasons behind OPG's decision not to file for new payment amounts in 2010. The introductory language to these sweeping requests is instructive. CME says the information is being requested "to help understand the circumstances which prompted" the decision not to file for new payment amounts effective January 1, 2010. It is OPG's submission, as set out in further detail below, that the Application has nothing to do with "the circumstances which prompted" the decision not to file for new payment amounts for 2010.

The intervenor argument which most fully articulates the attempt to justify CME interrogatory #1 comes, not surprisingly, from CME itself. At its core, CME's claim to relevance is founded on the assertion that information about whether current payment amounts are likely to produce a revenue sufficiency or deficiency in 2010 is needed in order to determine "whether any rate payer protection conditions should be attached to the Accounting Order being applied for." By "ratepayer protection conditions," CME means an "asymmetric [i.e., benefits only consumers, not OPG] Earnings Sharing Mechanism ("ESM")." CME's claim is that if OPG forecasts a material revenue sufficiency in 2010, it would be "unfair" to grant OPG any "extended expense protection" in the form of the continued operation of already approved deferral and variance accounts in 2010. For the reasons that follow, OPG submits this argument lacks merit and should be rejected.

OPG's Submission

OPG's submission is that the broad-ranging financial information sought by CME interrogatory #1 is irrelevant to this Application. As noted above, the Application is, in fact, narrow and relatively benign. It deals almost exclusively with deferral and variance accounts already approved by the OEB. The Application involves effectively no change to the status quo. It only seeks clarity with respect to the technical application of the language of the Payment Amounts Order. The Application seeks no disposition of any account balances or any change to OPG's OEB-approved payment amounts. All of these questions are for another day. In any event, in the case of the nuclear accounts recovered through Rider A, both the amounts and the amortization of recovery into 2010 and 2011 have already been approved by the OEB.

OPG submits that both the introductory language to CME interrogatory #1, and the CME argument itself, effectively concede that the request is outside the scope of the Application. CME's stated objective is to understand the circumstances of OPG's decision not to file for 2010 and to argue for "rate payer protection" measures in the form of an asymmetric ESM. This is wholly collateral to OPG's Application. Whatever the merit of this request, and OPG submits there is none, it is not for consideration or disposition in this Application. In the context of OPG's present application, therefore, CME's request is simply a form of procedural opportunism.

A full discussion of the reasons for the establishment of OPG's deferral and variance accounts appears at pp. 113 to 128 of the Decision. Conspicuously absent from any aspect of this discussion is any mention of revenue requirement or of any relationship between revenue requirement and deferral and variance accounts. This is hardly surprising, because the criteria for establishing deferral or variance accounts are independent of revenue requirement considerations. CME's request, by contrast, is almost entirely devoted to the collateral question of 2010 revenue requirement.

CME invokes unspecified possible "unfairness" because OPG's request is for expense "protection" in 2010. CME's reference to "extended expense protection" for OPG is misleading because, as OPG's answer to Board Staff interrogatory #2 shows (p. 2 Table), most of the accounts reflect credits to consumers, not debits. Of those accounts containing material debits, two, the PARTS and nuclear liability deferral accounts, reflect amounts and an amortization period already approved by the OEB. The other, the Bruce Lease Net Revenues Variance Account, is an account established by the OEB on its own motion, not as a result of any request by OPG (Decision, p. 112), and reflects the amount of credit to which consumers are entitled from net Bruce lease revenues under O. Reg. 53/05, as interpreted by the OEB in the Decision.

There is also no precedent for CME's request. No regulated utility of which we are aware in Ontario has been required, even as a condition of *confirmation* of previously approved deferral and variance accounts (which is not required here), to provide a wide ranging summary of actual to forecast financial information for the emerging test period and forecast revenue requirement information for future periods. Acceding to CME's request, therefore, particularly in light of the lack of any connection or relevance to the issues raised by the Application itself, is not, OPG submits at all conducive to regulatory efficiency.

CME's argument that the OEB should rarely if ever approve accounting order applications without broad knowledge of actual to forecast test period financial information and forecast financial information for future periods is unsupported and inconsistent with the reality of every day practice. The OEB regularly approves accounting order applications without requiring all this information. It is not, as CME alleges, "regulating in the dark" because the accounting orders themselves generally decide nothing of substance in terms of monetary entitlements. Matters of disposition are, as they will be in this case, left for another day.

Only two other intervenor submissions require further comment. The first is SEC's submission that the current payment amounts were "not intended to relate to any period past December 31, 2009." This is incorrect. The Payment Amounts Order, like virtually all OEB rate orders, while based on forward test year information, continues until changed by future order of the OEB. While it is fair to say that it was, at the time of the original payment amounts proceeding, OPG's expectation that there would be a new filing for 2010, there is nothing about the Decision or the Payment Amounts Order that changes the OEB-approved payment amounts after December 31, 2009.

Finally, the Energy Probe submission argues for an oral hearing to consider CME's request for an answer to CME interrogatory #1. It is notable that only Energy Probe, which asked no interrogatories, has made this request. In OPG' s submission, no oral hearing is required. The parties have already been afforded the opportunity to make full argument on the issue through the directions contained in Ms. Binette's August 10, 2009 email. Even CME, whose question it is, has not argued for the necessity of an oral hearing nor, in the circumstances, is one warranted or required. Energy Probe's request should be denied.

Conclusion

In conclusion, in answer to the three issues Ms. Binette directed be addressed:

1. The only issue regarding further discovery which has been raised is whether CME interrogatory #1 should be answered. OPG submits it should not be obliged to

answer this question on the basis that it is wholly collateral to the Application in which the question has been asked, that it is unnecessary and therefore irrelevant to the disposition of OPG's application and that requiring an answer to this question would unnecessarily complicate and delay the efficient disposition of this Application;

2. No form of further discovery or technical conference is required; and

3. The next steps in this Application should be as set out in the OEB's Procedural Order No. 1 in this proceeding.

Yours very truly,

Michael A. Penny

Tel 416.865.7526
mpenny@torys.com
MAP/jeb

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY EMAIL

August 18, 2009

To: All Parties to Proceeding EB-2009-0174

**Re: Ontario Power Generation Inc.
Application for Accounting Order Regarding Deferral and Variance Accounts**

By letter dated August 10, 2009, the Canadian Manufacturers & Exporters ("CME") has requested that the Board direct OPG to answer CME Interrogatory #1. OPG has refused to answer the interrogatory on the grounds that it is irrelevant to the proceeding CME maintains that the interrogatory is relevant "to a determination of whether any ratepayer protection conditions should be attached to the Accounting Order relief OPG seeks", namely an Earnings Sharing Mechanism of some type. The School Energy Coalition and Energy Probe Research Foundation have supported CME's request. By letter dated August 12, 2009, OPG confirmed its position that CME Interrogatory #1 is not relevant to the proceeding.

The Board has considered CME's request and has determined that it will not require OPG to answer CME Interrogatory #1.

The interrogatory requests data and calculations related to OPG's revenue requirement for 2010 as well as information on results for 2008 and 2009. The current proceeding is not an examination of OPG's 2010 revenue requirement; rather it is concerned with the ongoing implementation of various Board determinations in the last proceeding relating to deferral and variance accounts, and the ongoing recording of amounts in certain accounts. OPG is not seeking approval of any balances in this proceeding; nor is it seeking disposition of any balances, other than those that have already been approved by the Board.

The current payment amounts remain in place, pursuant to the Board's Order of December 2, 2008, until such time as they are changed, either as a result of OPG filing an application to change the payment amounts, or as a result of the Board initiating a proceeding on its own motion to determine whether the payment amounts remain just and reasonable.

CME may wish to raise at the next payments proceeding the issue of OPG's 2010 results and whether those results should be considered in the disposition of the deferral and variance accounts.

The Board concludes that the data and calculations requested in CME Interrogatory #1 are not required for purposes of the Board rendering a decision on OPG's application.

The original schedule will remain as set out in Procedural Order No.1.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

To the extent that there is no tax benefit to be matched to the variance account or deferral account recovery, an adjustment to regulatory earnings before tax is required. This is the case for the Nuclear Liability Deferral Account, where the majority of the underlying costs recorded in the account are not deductible for tax purposes (e.g., depreciation). Therefore, while the amortization of this account is shown as an addition to regulatory earnings before tax for 2008 to 2009 and 2010 to 2012 in Ex. F4-T2-S1 Table 6, line 6 and Table 5, line 6, respectively, there is a minimal deduction from earnings before tax. The amounts deducted for 2008 to 2009 and 2010 to 2012 are shown in Ex. F4-T2-S1 Table 6, line 18 and Table 5, line 19, respectively.

Similarly, in the case of the Income and Other Taxes Variance Account, some of the underlying amounts recorded in the account are not taxable (e.g., variance from forecast income tax expenses due to changes in the income tax rates). Accordingly, the portion of the amortization of this account that relates to amounts that are non-taxable is added back to regulatory earnings before tax in 2011 and 2012 in Ex. F4-T2-S1 Table 5, line 8.

An adjustment to regulatory earnings before tax is also required to address the regulatory treatment of the Bruce Lease net revenues. The forecast net revenues (after tax) from the Bruce Lease reduces OPG's revenue requirement, and therefore the earnings before tax for the prescribed facilities as shown in Ex. F4-T2-S1 Table 5, note 1. To the extent that there is a difference between the forecast and actual net revenues from the Bruce Lease, there is a difference in the regulatory earnings before tax and therefore the taxes for the prescribed facilities. Hence, an adjustment to regulatory earnings before tax is required in the year of recovery of this variance to ensure that any shortfall in regulatory taxes is also recovered from the ratepayers. Accordingly, the amortization of the Bruce Lease Net Revenues Variance Account is added back to regulatory earnings before tax in 2011 and 2012 in Ex. F4-T2-S1 Table 5, line 7.

4.0 TAX LOSSES PRIOR TO APRIL 1, 2008

For the years 2005 to 2007, OPG's regulated business incurred tax losses (negative regulatory taxable income), which were available to be carried forward for utilization in later years against regulatory taxable income of the regulated business. In its EB-2007-0905 Application, OPG presented the amount of tax losses available to be carried forward at the end of 2007 as $990.2M. The OEB subsequently directed OPG to recalculate the tax losses to reflect the OEB's findings in its Decision in EB-2007-0905. This recalculation resulted in the amount of the tax losses available to be carried forward at the end of 2007 to be $188.5M.

This section presents information with respect to the tax loss incurred in the years 2005 - 2007 and the first quarter of 2008. The tax loss calculation is supported in three ways:

- The actual regulatory tax losses are calculated starting from regulatory earnings before tax and applying the methodology and additions and deductions detailed in section 3 above. The calculations incorporate the directions of the OEB's Decision in EB-2007-0905, including the application of the principles that the party who bears a cost should be entitled to any related tax loss benefit and only the prescribed facilities are considered in the tax loss calculation. The calculation of these tax losses is presented in Ex. F4-T2-S1 Table 7 and discussed in section 4.1 below.

- The tax losses for 2005 - 2007 are reconciled with the tax loss calculations presented in OPG's evidence in EB-2007-0905. This reconciliation shows the adjustments to regulatory tax losses resulting from the OEB's Decision in EB-2007-0905. The reconciliation is presented in Ex. F4-T2-S1 Table 8 and is discussed in section 4.2 below.

- The determination of the tax expense for the prescribed facilities for 2005 – 2007 is reconciled with OPG's corporate income tax returns. This reconciliation responds to the direction on page 171 of the OEB's decision in EB-2007-0905 that OPG file an analysis of its prior period tax returns identifying all items that should be taken into account in the tax expense for the prescribed facilities. The reconciliation is presented in Ex. F4-T2-S1 Tables 10 - 12 and discussed in section 4.3 below.

OPG also engaged Ernst & Young to perform and report on specified procedures on the schedules presented in Ex. F4-T2-S1 Tables 10 – 12 reconciling information in OPG's corporate tax returns to the determination of prior period tax losses for the prescribed facilities for 2005, 2006 and 2007. These reports were prepared to assist the OEB and intervenors. The specified procedures tie the numbers on these schedules back to the underlying OPG source documentation. This source documentation includes OPG's tax returns, OPG's audited consolidated financial statements, general ledger accounts and certain internal reports and management prepared schedules and worksheets.

The specified procedures were applied by Ernst & Young in accordance with Canadian Institute of Chartered Accountants ("CICA") Handbook Section 9100. A copy of the Ernst & Young reports for 2005, 2006 and 2007 are filed as Attachment 1. By applying the specified procedures, Ernst & Young was able to tie the numbers on the schedules back to the source documents with no exceptions. As a result, Ernst & Young confirmed that the numbers shown in the schedules (Ex. F4-T2-S1 Tables 10-12) have been agreed to source documents including tax returns filed by OPG, audited financial statement and supporting general ledger accounts, or other reports and schedules as set out in the specified procedures reports.

4.1 Calculation of Actual Tax Losses for April 1, 2005 – March 31, 2008

The cumulative tax losses for the years 2005 to 2007 are $210.4M, (2005 – $87.4M; 2006 – $84.7M; 2007 – $38.3M). Excluding the tax loss of $21.9M related to the period prior to April 1, 2005, which was the effective date of payments amounts established pursuant to O. Reg. 53/05, the cumulative revised tax losses are $188.5M. The determination of the pre-April 1, 2005 tax loss of $21.9M is based on a straight-line pro-ration of the 2005 annual tax loss.

The resulting cumulative tax losses of $188.5M were used to reduce the taxable income of $77.6M for the period January 1, 2008 to March 31, 2008 to nil, resulting in remaining net cumulative tax losses of $110.9M, as presented in lines 20 – 29 of Ex. F4-T2-S1 Table 7 and reproduced in Chart 1 below.

Chart 1

Calculation and Utilization of Prior Period Regulatory Tax Losses ($M)
Years Ending December 31, 2005, 2006 and 2007 and Three Months Ending March 31, 2008

Line No.	Particulars	2005 Actual	2006 Actual	2007 Actual	January 1 to March 31, 2008 Actual
		(a)	(b)	(c)	(d)
20	**Regulatory Taxable Income / (Loss) Before Allocation to Period Prior to Regulation and Loss Carry-Over**	(87.4)	(84.7)	(38.3)	77.6
21	**Allocation to Period Prior to Regulation**[1]	21.9	N/A	N/A	N/A
22	**Regulatory Taxable Income / (Loss) Before Loss Carry Over**	(65.5)	(84.7)	(38.3)	77.6
23	**Tax Loss Carry-Over to Future Periods / (from Prior Periods)**	65.5	84.7	38.3	(77.6)
24	**Tax Loss Available for Mitigation in EB-2007-0905 as at March 31, 2008**				(110.9)
	Utilization of Prior Period Tax Losses				
25	**Taxable Income for Year Ending December 31, 2008**[2]				116.9
26	**Less: Tax Loss Utilized During Three Months Ending March 31, 2008**				(77.6)
27	**Tax Loss Utilized During Nine Months Ending December 31, 2008**				39.2
28	**Tax Loss Utilized During Year Ending December 31, 2009**[2]				71.6
29	**Total Tax Loss Utilized as at December 31, 2009** (line 27 + line 28)				110.9

Notes:
1 Allocation to Period Prior to Regulation refers to the portion of the 2005 tax loss attributable to the period January 1, 2005 to March 31, 2005, as discussed in Ex. F4-T2-S1.
2 The amounts are presented in Ex. F4-T2-S1 Table 6.

4.2 Reconciliation to Evidence in EB -2007-0905

The adjustments from the amount of tax losses of $990.2M at the end of 2007 presented in the evidence in EB-2007-0905 to the revised amount of $188.5M are presented in Ex. F4-T2-S1 Table 8 and are discussed below. Ex. F4-T2-S1 Table 8 is reproduced below as Chart 2 for ease of reference. The tax tables filed in EB-2007-0905 are provided at Ex. F4-T2-S1 Attachment 2 for reference.

Chart 2

Reconciliation of Prior Period Regulatory Tax Losses ($M)
Years Ending December 31, 2005, 2006, 2007 and Three Months Ending March 31, 2008

Line No.	Particulars	2005 Actual	2006 Actual	2007 Actual	Total
		(a)	(b)	(c)	(d)
	Per OPG's Original Filing EB-2007-0905[1]:				
1	**Loss for the Year**	(364.4)	(101.2)	(553.0)	(1,018.6)
2	**Allocation to Period Prior to Regulation[2]**	28.4	0.0	0.0	28.4
3	**Loss Available to be Carried Forward**	(336.0)	(101.2)	(553.0)	(990.2)
	Adjustments to Original Income / (Loss) for the Year:				
4	**Adjustment to Timing of PARTS Costs Deduction**	254.0	(12.0)	(95.0)	147.0
5	**Exclusion of Impact of Bruce Revenues and Costs[2]**	19.9	28.5	341.6	390.0
6	**Adjustment for Operating Losses Borne by OPG's Shareholder[3]**	3.1	0.0	231.1	234.2
7	**Update of Tax Information for 2007**	N/A	N/A	37.0	37.0
8	**Total Adjustments Before Allocation to Period Prior to Regulation**	277.0	16.5	514.7	808.2
9	**Allocation of Adjustments to Period Prior to Regulation[4]**	(6.5)	0.0	0.0	(6.5)
10	**Adjusted Loss for the Year** (Line 3 + Line 8 + Line 9)	(65.5)	(84.7)	(38.3)	(188.5)
11	**Income for Q1 2008**				77.6
12	**Adjusted Tax Loss as at March 31, 2008**				(110.9)

Notes:
1 As filed in OPG's application EB-2007-0905 in Ex. F3-T2-S1 Table 9 (see Attachment 2).
2 Calculation of impact of Bruce revenues and costs is presented in Ex. F4-T2-S1 Table 16.
3 Calculation of operating losses for prescribed assets borne by OPG's Shareholder is presented in Ex. F4-T2-S1 Table 17.
4 Allocation to Period Prior to Regulation refers to the portion of the 2005 tax loss / tax loss adjustments attributable to the period January 1 to March 31, 2005, as discussed in Ex. F4-T2-S1.

4.2.1 <u>$147.0M Reduction Due to Timing of PARTS Costs Deduction</u>

The cost recorded in the PARTS deferral account result in a tax benefit. OPG's EB-2007-0905 Application included a deduction for the full amount of the PARTS costs of $258.0M and $13.0M in 2005 and 2006, respectively, the same years in which these costs were incurred. This deduction was presented in Ex. F3-T2-S1 Table 8, line 18 in EB-2007-0905. This treatment did not match the timing of the tax benefit of these costs to their recovery from ratepayers through approved payment amounts. Consistent with the requirement of the OEB as set out on page 170 of the EB-2007-0905 Decision, OPG is providing the tax benefit related to the PARTS costs deduction to ratepayers to coincide with the timing of the recovery of costs, including interest on the deferral account, from ratepayers.

This adjustment ensures that the amount of the deduction equals the amortization (recovery) of the PARTS deferral account of $4.0M and $25.0M in 2005 and 2006, respectively (as presented in EB-2007-0905, Ex. F3-T2-S1 Table 8, line 7) and $95.0M in 2007 (as presented in EB-2007-0905, Ex. F3-T2-S1 Table 7, line 7). This adjustment resulted in a reduction to tax losses of $147.0M over the 2005 - 2007 period.

The regulatory tax calculations over the remaining recovery period for the PARTS balance, ending at December 31, 2011, include a deduction corresponding to the amount being recovered through payment amounts. Accordingly, this adjustment represents only a difference in the timing of the benefit being received by ratepayers and the total benefit remains the same. In EB-2007-0905, the entire benefit associated with the PARTS account was received in 2005 - 2007 whereas in this Application, the benefit is provided over the period of 2005 - 2011 consistent with the amortization period of the PARTS account.

4.2.2 <u>$390.0M Reduction Resulting From Exclusion of Impact of Bruce Revenues and Costs</u>

OPG's EB-2007-0905 Application presented regulatory earnings/(losses) before tax in Ex. F3-T2-S1 Tables 7 and 8, line 1 for 2005 - 2007 of $106.0M, $193.8M and ($84.0M) that included both prescribed facilities and Bruce assets. The OEB determined in EB-2007-0905 on page 169 that "any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease," and further noted on page 171 that "the income tax provision for the prescribed facilities in future applications should not include any income or loss in respect of the Bruce lease." Consequently, OPG removed earnings before tax related to Bruce assets and related additions and deductions to those earnings, resulting in the removal of tax losses of $19.9M, $28.5M, and $341.6M for 2005, 2006 and 2007, respectively. Accordingly, total losses for years 2005 – 2007 were reduced by $390.0M. The calculation of the impact of Bruce revenues and costs on prior period regulatory tax losses is presented in Ex. F4-T2-S1 Table 16.

4.2.3 <u>$234.2M Reduction for Operating Losses Borne by OPG's Shareholder</u>

After the exclusion of earnings before tax related to Bruce assets described above, the operating losses before tax related to prescribed facilities were $3.1M and $231.1M in 2005 and 2007, respectively. The reconciliation of the losses for the prescribed facilities for 2007 to OPG's annual audited consolidated financial statements is provided in Ex. F2-T4-S1 Table 17.

In its EB-2007-0905 Decision, the OEB made the following observations regarding OPG's operating losses on page 170:

> 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 losses in years 2005 and 2007 were borne by OPG's shareholder, and as such OPG excluded these losses by setting the earnings before tax in those years to nil. Comparison of the forecast versus actual nuclear production in 2007 verifies that the loss of $231.1M in 2007 was borne by OPG's shareholder. OPG's actual nuclear production for 2007 was 44.2 TWh as presented in Ex. E2-T1-S1 Table 1 which was 8.8 TWh lower than the forecast production of 53.0 TWh provided to the Province for the purposes of setting interim payment amounts for the period up to April 1, 2008. The forecast production is provided in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" which is referenced in O. Reg. 53/05 and posted on the OEB's website at the following url:

http://www.oeb.gov.on.ca/documents/cases/EB-2006-0064/forecast_facilities_opg_20070213.pdf

Based on the nuclear payment amount of $49.50/MWh, the lower production resulted in lower revenues to OPG of approximately $435.6M. OPG's shareholder was not compensated by the ratepayers for these foregone revenues, and hence should retain the benefit of the associated tax losses. This treatment is consistent with the principle noted by the OEB in its Decision on page 170 that "the party who bears a cost should be entitled to any related tax savings or benefits."

4.2.4 <u>$37.0M Reduction Due to Update of Tax Information for 2007</u>

The tax information provided in EB-2007-0905 for 2007 was based on OPG's 2007 year-end income tax provision, not its actual tax expense, because the final tax expense was not yet available. The tax information for 2005 and 2006 used the actual tax expense. The actual 2007 tax expense was determined when OPG filed its income tax returns for 2007 in June 2008. OPG's calculation of prior period tax losses for this Application reflects actual tax expense for 2005, 2006 and 2007 based on the information contained in its income tax returns, applying a consistent treatment for all years in the prior period. The difference between use of the 2007 income tax provision in EB-2007-0905 and the actual tax expense results in a reduction to the tax losses of $37.0M.

4.2.5 <u>$6.5M Addition from Allocation of Adjustments to Period Prior to Regulation</u>

The adjustment of $6.5M represents the difference in the amount of the 2005 tax loss attributable to the period prior to April 1, 2005 as a result of the redetermination of the loss. The original amount attributable to that period was $28.4M (Ex. F4-T2-S1 Table 8), and the revised amount is $21.9M (Ex. F4-T2-S1 Table 7).

4.3 Analysis of Prior Period Tax Returns

In the OEB's Decision in EB-2007-0905, the OEB stated that it expected OPG to file an analysis of its prior period tax returns. The analysis for each of the years 2005, 2006 and 2007 is presented in Ex. F4-T2-S1 Tables 10, 11 and 12, respectively. This analysis reconciles the calculation of OPG's consolidated taxable income to the calculation of the regulatory taxable income for the prescribed facilities.

Since OPG's regulated and unregulated businesses operate within several number of legal entities, the analysis includes a reconciliation to exclude amounts related to OPG's unregulated operations. Below is a detailed explanation of the columns in the reconciliation tables:

- The amounts in Column 1 are as per the OPG Inc. legal entity tax return for the applicable year. The copies of the tax returns for 2005 - 2007 are provided at Ex. F4-T2-S1 Attachment 3. The amounts in Column 2 are as per OPG Inc. subsidiaries' tax returns for that year, which are provided at Ex. F4-T2-S1 Attachment 3.
- Column 3 represents the consolidated amounts for OPG Inc. and its subsidiaries (total of the amounts in Columns 1 and 2). The total earnings before tax ("EBT") in this column represents the EBT as reported in OPG's consolidated audited financial statements for the applicable years.
- Amounts relating to OPG's unregulated operations, excluding the Bruce assets, (e.g., fossil, unregulated hydroelectric) are reported in Column 4.
- The balances reported in Column 5, which represents the subtraction of Column 4 from Column 3, are the amounts that relate to what OPG reports on its consolidated financial statements as its "regulated" business segment. For financial reporting purposes, this segment includes the prescribed facilities and the Bruce assets.
- Column 6 represents the removal of items relating to Bruce assets as required by the OEB in it Decision in EB-2007-0905
- Certain items of income and expenses are not refundable or recoverable from ratepayers as they do not form part of the revenue requirement calculation. Certain other items are refunded or recovered over a period of time. Accordingly, certain amounts in Column 6 are adjusted or eliminated in Column 7 for the purposes of the regulatory tax calculation. Some of the more significant adjusting items in Column 7 are:
    - Accretion expense for the nuclear liabilities for 2005 - 2007: this item does not form part of regulatory earnings before tax based on the OEB-approved methodology of recovering nuclear liabilities for the prescribed facilities.
    - One-time adjustment with respect to the write-off of Pickering A Units 2 and 3 inventory and CIP in 2005: OPG did not recover these costs from ratepayers and therefore the associated tax benefit is not included in the calculation of regulatory taxable income.
    - Investment income earned by the nuclear segregated funds for 2005 - 2007: this item does not form part of regulatory earnings before tax based on the OEB-approved methodology of only recovering nuclear liabilities for the prescribed facilities.

- Adjustments to the timing of PARTS costs deduction taken by OPG in 2005 and 2006 to match the recovery of these costs from ratepayers over time, as explained above in section 4.0 under the heading "Adjustment to Timing of PARTS Costs Deduction".
- Changes in the CCA amounts for 2005 - 2007 due to the resolution of the 1999 income tax audit, which resulted in changes to the undepreciated capital cost balances for the prescribed facilities. The impact of the changes in the CCA resulting from the resolution of the 1999 income tax audit were reflected in OPG's EB-2007-0905 Application. These changes were not reflected in OPG's tax returns as filed, resulting in the need for the reconciling item in this table.
- Construction in Progress ("CIP") interest for 2005 - 2007: the amount of OPG's actual interest is replaced by deemed interest for regulatory purposes.
- Adjustment related to duplicate interest deduction, which is described in section 3.3.6 above.

- The result of the above adjustments to amounts in Column 6 is presented in Column 8, which represents the regulatory tax calculation for 2005 – 2007 as presented in Ex. F4-T2-S1 Table 7.

5.0 INCOME TAX EXPENSE 2008-2009

5.1 Benchmark Income Tax Expense April 1, 2008 to December 31, 2009

In its EB-2007-0905 Decision, the Board directed OPG to provide a benchmark of income tax expense for the prescribed facilities, without consideration of tax losses prior to April 1, 2008, for the test period April 1, 2008 to December 31, 2009. It has been computed using the OEB-approved revenue requirement for that period in a manner consistent with the Board's Direction. The computation of the expense, which totals $66.0M for the period ($37.5 for the period April 1 to December 31, 2008 and $28.5M for the period January 1 to December 31, 2009), is presented in Ex. F4-T2-S1 Table 9. The expense is computed in the same manner as the regulatory income tax expense for the historic, bridge and test period years, applying the principles described in section 3 and the OEB's direction in EB-2007-0905 outlined in section 4. The application of the OEB's direction includes the exclusion of the tax impact of revenues and costs related to the Bruce assets and the adjustment to the timing of the deduction for PARTS costs.

The tax expense of $37.5M for the period April 1, 2008 to December 31, 2008 is higher than the tax expense of $28.5M for the full year 2009 primarily due to lower annualized contributions to segregated funds for the prescribed nuclear facilities in 2008. The total benchmark tax expense of $66.0M is consistent with the tax expense included in OPG's Submission re: Notice of Motion to Vary, EB-2009-0038, page 15, Table 1, line 11.

5.2 Actual Income Tax Expense 2008 - 2009

The actual annual income tax expense for the prescribed facilities for years 2008 and 2009 has been computed using the same approach as described in section 3 and the OEB's direction in EB-2007-0905 outlined in section 4. The computation of taxable income, before consideration of the utilization of prior period tax losses, totals $116.9M for 2008 and $305.6M for 2009, as presented in Ex F4-T2-S1 Table 6. The taxable income for 2008 was offset by the utilization of prior period tax losses presented in Ex. F4-T2-S1 Table 7, resulting in an actual tax expense of nil. The 2009 taxable income was partially offset by the utilization of the balance of the prior period losses, resulting in actual income tax expense of $68.0M.

6.0 INCOME TAX EXPENSE FOR 2010 - 2012

The regulatory income tax expense calculations for the prescribed facilities for the bridge year and test period are shown in Ex F4-T2-S1 Table 5. The forecast income tax expense for years 2010 - 2012 has been computed using the same approach as described in section 3 and the OEB's direction in EB-2007-0905 outlined in section 4. The additions and deductions to regulatory earnings before tax for the bridge and test periods are consistent with those in the period 2005 to 2007, apart from one-time adjustments in those years and adjustments for SR&ED ITCs discussed in section 7.1 below.

The forecast tax expense in the test period years of 2011 and 2012 is $84.4M and $103.3M, respectively.

The forecast expense in the bridge year of 2010 is $16.5M. The tax expense for 2010 is forecast to be lower that the tax expense for the test years primarily due to lower earnings before tax.

Board Staff Interrogatory #117

Ref: Ex. EB-2007-0905, Payment Amounts Order, Appendix A, Table 3

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

a) Please confirm that the approved revenue requirement before mitigation (line 4) of $6,173.0 M does not include any income tax PILs.

b) Please confirm that the revenue deficiency before mitigation (line 5) of $767.0 M does not include any income tax PILs.

c) Please confirm that the mitigation prescribed by the Board: 22% of revenue deficiency (line 6) of $168.6 M, does not include any income tax PILs.

d) Please provide a calculation of regulatory income taxes for 2008 (9 months) and 2009 (whole year) based on the total test period revenue requirement before mitigation of $6,173.0 M. From the referenced Table 3, the total revenue requirement amounts for 2008 were $2,638.5 (506.2 + 2,132.3) M and $3,534.5 (674.2 + 2,860.3) M for 2009.

Response

a) OPG confirms that the approved revenue requirement before mitigation of $6,173.0M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 4) does not include any regulatory income tax.

   This is evident from the same appendix in Tables 1 and 2 that builds up the total approved revenue requirement before mitigation ($1,180.4M for regulated hydroelectric in Table 1, line 24 and $4,992.6M for nuclear in Table 2, line 24). Line 23 on Tables 1 and 2 entitled “Income Tax” shows $Nil.

b) OPG confirms that the revenue deficiency before mitigation of $767.0M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 5) does not include any regulatory income tax.

   As this revenue deficiency amount represents the difference between the indicated production revenue on line 3 based on the then existing payment amounts and the approved revenue requirement (before mitigation) on line 4 that does not include any regulatory income tax per part a) above, the revenue deficiency figure is <u>understated</u> by the amount of income tax related to the approved revenue requirement (before mitigation) of $6,173.0M. This figure is $172.5M as discussed in part d) below. As such, the revenue deficiency figure on line 5 would have been $939.5M and the approved revenue requirement before mitigation would have been $6,345.5M if regulatory income tax was included.

c) OPG confirms that 22 per cent of the revenue deficiency of $168.6M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 6) does not include any regulatory income taxes because, as explained above in part b), the revenue deficiency itself does not contain any regulatory income taxes.

d) The requested calculation is found in the attached Table 1. Based on the table, the total regulatory income tax (including the tax gross-up) for the 21-month period ended December 31, 2009 associated with the approved revenue requirement before mitigation is $172.5M ($88.0M for 2008 plus $84.6M for 2009, difference due to rounding). Therefore, this amount forms part of the revenue requirement reduction calculation of $341.2M for the Tax Loss Variance Account shown in Ex. H1-T1-S1, Table 4, Note 1 ($66.0M + $106.5M = $172.5M).

OPG notes that the calculation of regulatory income taxes based on the pre-mitigation revenue requirement of $6,173.0M in Table 1 recognizes that this revenue requirement itself excludes regulatory taxes (as noted in part a)), and therefore the appropriate calculation of regulatory income taxes based on this revenue requirement should provide for both the incremental taxes associated with adding back the mitigation amount of $168.6M and the foregone tax expense for 2008-2009 on the post-mitigation revenue requirement. This approach is consistent with OEB's findings in EB-2009-0038 that the OEB ordered both the exclusion of the 2008 – 2009 regulatory income tax expense[1] and a further mitigation amount of $168.6M[2].

[1] On page 12 of Decision and Order in EB-2009-0038, the OEB stated regarding EB-2007-0905 that "the Board found that OPG should reduce its revenue requirement by eliminating any tax provision for 2008 and 2009."

[2] On page 13 of Decision and Order in EB-2009-0038, the OEB stated regarding EB-2007-0905 that "in addition, the Board ordered OPG to reduce its revenue requirement by 22 per cent of its revenue deficiency."

Table 1
Calculation of Regulatory Income Tax Expense Based on Pre-Mitigation Revenue Requirement ($M)
Nine Months Ending December 31, 2008 and Year Ending December 31, 2009

Line No.	Particulars	April 1 to Dec 31, 2008 Budget	2009 Plan
		(a)	(b)
		Note 1	Note 1
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[2]	201.0	230.5
2	**Additions for Regulatory Tax Purposes:**		
3	**Depreciation and Amortization**	264.1	376.3
4	**Nuclear Waste Management Expenses**	25.4	24.2
5	**Receipts from Nuclear Segregated Funds**	25.5	29.0
6	**Pension and OPEB/SPP Accrual**	264.8	337.0
7	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	36.0	48.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	44.5	56.7
9	**Other**	6.8	10.0
10	**Total Additions**	667.1	881.2
	Deductions for Regulatory Tax Purposes:		
11	**CCA**	226.5	306.0
12	**Cash Expenditures for Nuclear Waste & Decommissioning**	72.7	83.0
13	**Contributions to Nuclear Segregated Funds**	54.7	135.0
14	**Pension Plan Contributions**	174.8	239.0
15	**OPEB/SPP Payments**	51.0	73.0
16	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	2.0	2.3
17	**Other**	6.9	0.6
18	**Total Deductions**	588.6	838.9
19	**Regulatory Taxable Income**	279.5	272.8
20	**Income Tax Rate**	31.50%	31.00%
21	**Regulatory Income Taxes**	88.0	84.6
	Income Tax Rate:		
22	**Federal Tax**	19.50%	19.00%
23	**Provincial Tax**	14.00%	14.00%
24	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
25	**Total Income Tax Rate**	31.50%	31.00%

Notes:
1 All additions and deductions for regulatory tax purposes (Lines 2-18) are in the same amount as presented in Ex. F4-T2-S1, Table 9 in EB-2010-0008.

2 Regulatory Earnings Before Tax are computed as follows ($M):

Line No.	Particulars	2008	2009
1	Regulatory Earnings Before Tax from Ex. F4-T2-S1, Table 9, Line 1	40.7	49.5
2	Tax on Post-Mitigation Revenue Requirement per EB-2007-0905, Payment Amounts Order (Ex. F4-T2-S1, Table 9, Line 21 x 1 / (1-tax rate))	54.7	41.3
3	Mitigation per EB-2007-0905, Payment Amounts Order, App A, Table 3, Note 3	72.3	96.4
4	Tax on Mitigation Amount per Line 3 above (Line 3 x tax rate / (1-tax rate))	33.2	43.3
5	Regulatory Earnings Before Tax (Line 1+2+3+4)	201.0	230.5

Board Staff Interrogatory #118

Ref: Ex. F4-T2-S1, Table 6 - Actual Regulatory Income Taxes for 2008 and 2009

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

a) Please describe how OPG ensured that the calculations shown on Table 6 for actual 2008 and 2009 are consistent with the methodology used by Ernst & Young in ExhF4/Tab2/Sch1/Attachment1 for the years 2005 through 2007. Please provide the supporting analysis and worksheets.

b) Are the numbers shown in Table 6 derived from the actual tax returns for 2008 and 2009? If not, please provide alternate calculations that are derived from the actual tax returns.

c) In Table 7 the actual regulatory taxable income for January 1 to March 31, 2008 is shown as a profit of $77.6 M. In Table 6 the regulatory taxable income for the whole year 2008 is only $116.9 M. By subtraction, the regulatory taxable income for the 9 months of the prior 2008 test period was only $39.3 M.

   i) Please explain the steps OPG took to ensure that the financial and accounting cut-off procedures for the first quarter 2008 were correct, and that the procedures resulted in the correct taxable income for the first quarter.

   ii) Why was the taxable income for the first quarter 2008 so large in comparison to the last 9 months of 2008?

Response

a) The calculations and reconciliations to corporate income tax returns for 2005 – 2007 as presented in Ex. F4-T2-S1, Schedule A of Attachment 1 were prepared by OPG in accordance with the methodology outlined in sections 3 and 4 of Ex. F4-T2-S1 (these calculations are also presented in Ex. F4-T2-S1, Tables 10-12). Specifically, section 4.3 outlines the methodology used by OPG in preparing the reconciliations of the regulatory income tax calculations to corporate income tax returns. Ernst & Young was then engaged to perform and report on specified procedures relating to the OPG-prepared schedules to reconcile the tax return information to the regulatory tax expense for OPG's prescribed facilities. For each of the years, the procedures were applied and a separate report was produced by Ernst & Young. The reports provide a detailed account of the exact procedures performed and the specific results of those procedures. By applying the specified procedures, Ernst & Young found no exceptions.

The calculations of actual regulatory annual income tax expense for the prescribed facilities for years 2008 and 2009, presented in Ex. F4-T2-S1, Table 6, have been prepared by OPG using the same approach as outlined in section 3 of Ex. F4-T2-S1 and used by OPG in preparing the calculations for 2005 – 2007. In response to the interrogatory in Ex. L-1-120, part c), OPG also provides reconciliations to the corporate income returns for 2008 and 2009 prepared using the same methodology as outlined in section 4.3 of Ex. F4-T2-S1.

b) The numbers shown in Table 6 for 2008 are derived from the actual tax returns. The 2009 numbers are derived from the year-end tax provision, as the tax returns had not yet been filed with the tax authorities at the time of the submission of the pre-filed evidence for this Application. The attached Table 1 is presented in the same format as Table 6 noted above, with updated calculations for 2009 based on the actual tax returns. In response to the interrogatory in Ex. L-1-120, part c), OPG also provides reconciliations to the corporate income tax returns for 2008 and 2009.

OPG notes that the updated calculations in Table 1 based on the 2009 actual tax returns result in a small change to the amount of regulatory income taxes. Table 1 shows $67.0M as compared to $68.0M in Ex. F4-T2-S1, Table 6.

c) (i) Assurance for adequate financial and accounting cut-off is primarily based on financial system period end cut-offs, which are clearly established and communicated with finance contacts through the use of formal planning meetings and a documented fiscal calendar that is available to all staff. OPG's financial systems restrict access to only authorized individuals within the period and any financial changes required subsequent to the period-end must be specifically authorized by management.

For the calculation of the taxable income, the Tax Department uses the accounting data based on the financial period end cut-offs established by OPG. As explained in Ex. F4-T2-S1, sections 3.2 and 3.3, OPG computes the regulatory taxable income by making additions and deductions to the regulatory earnings before tax for items affected by different regulatory accounting and tax treatment, applying the same principles used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. In calculating the taxable income for the first quarter of 2008, OPG used the actual numbers recorded in OPG's accounting records (e.g., depreciation, nuclear waste management expenses, etc.). For certain items (e.g., capital cost allowance), which are only available on an annual basis, OPG used the budget amount and prorated it for the first quarter.

ii) The regulatory taxable income for the first quarter 2008 was $77.6M as compared to the regulatory taxable income of $39.2M for the last nine months of 2008. The lower regulatory taxable income in the last nine months of 2008 reflects the impact on regulatory earnings before tax of lower than forecast nuclear production and higher gross revenue charge ("GRC") at regulated hydroelectric facilities (as a result of the property component of the GRC rates increasing as production levels increase) during the last nine months of 2008.

Table 1
Calculation of Regulatory Income Taxes - Updated for 2009 Tax Returns ($M)
Years Ending December 31, 2008 and 2009

Line No.	Particulars	2008 Actual	2009 Actual
		(a)	(b)
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[1]	20.8	257.3
	Additions for Regulatory Tax Purposes:		
2	**Depreciation and Amortization**	350.9	379.6
3	**Nuclear Waste Management Expenses**	21.4	22.7
4	**Receipts from Nuclear Segregated Funds**	62.5	65.7
5	**Pension and OPEB/SPP Accrual**	324.8	193.3
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	35.6	47.5
7	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	17.0
8	**Adjustment Related to Duplicate Interest Deduction (Q1 2008)**	10.0	0.0
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**	53.9	65.0
10	**Taxable SR&ED Investment Tax Credits of Prior Periods**	0.0	37.9
11	**Other**	41.5	61.1
12	**Total Additions**	900.7	889.7
	Deductions for Regulatory Tax Purposes:		
13	**CCA**	298.8	294.1
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	122.6	129.3
15	**Contributions to Nuclear Segregated Funds**	58.9	124.7
16	**Pension Plan Contributions**	198.6	211.1
17	**OPEB/SPP Payments**	63.6	61.8
18	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	1.8	2.4
19	**SR&ED Qualifying Capital Expenditures**	16.8	0.0
20	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	28.3	19.3
21	**Other**	15.2	2.1
22	**Total Deductions**	804.6	844.7
23	**Regulatory Taxable Income Before Carry Over of Loss Available for Mitigation in EB-2007-0905**	116.9	302.3
24	**Carry Over of Loss Available for Mitigation in EB-2007-0905**	(116.9)	(71.6)
25	**Regulatory Taxable Income After Loss Carry-Over**	0.0	230.6
26	**Regulatory Income Taxes - Federal** (line 25 x line 29)	0.0	43.8
27	**Regulatory Income Taxes - Provincial** (line 25 - line 10) x (line 30 + line 31)	0.0	23.1
28	**Total Regulatory Income Taxes**	0.0	67.0
	Income Tax Rate:		
29	**Federal Tax**	19.50%	19.00%
30	**Provincial Tax**	14.00%	14.00%
31	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
32	**Total Income Tax Rate**	31.50%	31.00%

Notes:
1 Regulatory Earnings Before Tax for 2008 and 2009 are reconciled to the corresponding Earnings Before Interest and Tax per the audited financial statements for OPG's Prescribed Facilities in Ex. C1-T1-S1, Table 7, Line 13.

Board Staff Interrogatory #119

Ref: Ex. F4-T2-S1, Table 9 Benchmark Regulatory Income Taxes 2008 and 2009

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

a) Please provide the supporting documents and calculations that show how the regulatory earnings before tax were derived for 9 months 2008 of $40.7M, and $49.5M for the whole year 2009.

b) Please provide the budget numbers for the first quarter 2008, and the whole year 2008 that support the numbers shown for the last 9 months of 2008 Budget. Please provide any explanations necessary to understand the process in creating these numbers.

c) Why is one column called 2008 Budget and the other 2009 Plan? What are the differences between a Budget and a Plan?

d) Are the 2008 Budget and 2009 Plan the same numbers that were used in EB-2007-0905 to derive the Payment Amounts Order? If not, please explain and provide all of the necessary reconciliations to explain the differences.

e) Regulatory earnings are shown as $257.3M in the 2009 Actual numbers in Table 6. In Table 9 the 2009 Plan shows regulatory earnings of only $49.5M. Please explain the significant difference between the Actual and the Plan regulatory earnings for 2009.

Response

a) Refer to Attachment 1.

b) Refer to Attachment 2 and accompanying notes.

c) When OPG's Board of Directors approves the annual Business Plan, it approves the first year of the plan as the "Budget", which becomes the reporting and accountability base against which corporate performance is monitored during the upcoming year. Subsequent years of the plan are referred to as the "Plan", which becomes a reference base for planning.

The calculation provided in Ex. F4-T2-S1, Table 9 was based on OPG's 2008 – 2012 Business Plan, which was the basis of OPG's Application in EB-2007-0905. In that business plan, 2008 was the budget year, and years 2009 and onwards were considered the “Plan” years.

This naming convention is used throughout this Application.

d) Yes, the numbers used in the calculation of the Benchmark Regulatory Taxes for 2008 and 2009 presented in Ex. F4-T2-S1, Table 9 are the same numbers that were used in EB-2007-0905 to derive the Payment Amounts Order.

e) The actual regulatory earnings for 2009, as shown in Ex. F4-T2-S1, Table 6, were significantly higher than the regulatory earnings underlying the calculation of the benchmark tax expense, as shown in Ex. F4-T2-S1, Table 9, primarily due to the recognition of the Tax Loss Variance Account amount of $292M in 2009 income for accounting purposes. Refer to Ex. L-12-041 for discussion of accounting for the Tax Loss Variance Account.

Numbers may not add due to rounding.

Table 1
Calculation of Regulatory Earnings Before Tax for Benchmark Tax Expense ($M)
Nine Months Ending December 31, 2008 and Year Ending December 31, 2009

Line No.	Particulars	EB-2007-0905 Payment Amounts Order Reference	Apr-Dec 2008	Jan-Dec 2009
			(a)	(b)
1	**Nuclear Return on Equity**	App. A, Table 2, Line 12, cols. (c) and (f)	74.7	100.5
2	**Less: Bruce Lease Net Revenues**	App A, Table 2, Line 20, cols. (c) and (f)	80.0	111.9
3	**Regulated Hydroelectric Return on Equity**	App A, Table 1, Line 12, cols. (c) and (f)	118.3	157.3
4	**Less: Mitigation Amount Ordered by the OEB**	App A, Table 3, Note 3	72.3	96.4
5	**Regulatory Earnings Before Tax** (Lines 1-2+3-4)		40.7	49.5

Numbers may not add due to rounding.

Table 2
Calculation of Benchmark Regulatory Income Tax Expense ($M)
For the Period April 1, 2008 to December 31, 2008

Line No.	Description	Note	2008 Full Year (unadjusted)	Q1 2008 (unadjusted)	April 1 to Dec. 31, 2008 (unadjusted)	Adjustments	April 1 to Dec. 31, 2008 Benchmark
			(a)	(b)	(c)	(d)	(e)
			Note 1		Note 2		
1	**Regulatory Earnings Before Tax**	3, 8	472.0	(79.0)	393.0	(352.3)	40.7
	Additions for Tax Purposes:						
2	**Depreciation and Amortization**	4, 9	408.0	(91.5)	316.5	(52.4)	264.1
3	**Nuclear Waste Management Expenses**	2, 9	48.0	(12.0)	36.0	(10.6)	25.4
4	**Receipts from Nuclear Segregated Funds**	2, 9	49.0	(12.2)	36.8	(11.3)	25.5
5	**Pension and OPEB/SPP Accrual**	2	353.0	(88.2)	264.8	0.0	264.8
6	**Regulatory Asset Amortization - PARTS Deferred Costs**	5, 10, 17	39.0	(27.4)	11.6	24.0	35.6
7	**Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	6, 11, 16	8.0	-	8.0	(4.4)	3.6
8	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	6	36.0	-	36.0	0.0	36.0
9	**Adjustment Related to Duplicate Interest Deduction**	2, 15	56.0	(14.0)	42.0	(42.0)	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	15			0.0	44.5	44.5
11	**Other**	2, 9	11.0	(2.7)	8.3	(1.5)	6.8
12	**Total Additions**		1,008.0	(248.0)	760.0	(53.7)	706.3
	Deductions for Tax Purposes:						
13	**CCA**	2, 9	311.0	(77.7)	233.3	(6.8)	226.5
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	2, 9	226.0	(56.5)	169.5	(96.8)	72.7
15	**Contributions to Nuclear Segregated Funds**	2, 9	454.0	(113.5)	340.5	(285.8)	54.7
16	**Pension Plan Contributions**	2	233.0	(58.2)	174.8	0.0	174.8
17	**OPEB/SPP Payments**	2	68.0	(17.0)	51.0	0.0	51.0
18	**Regulatory Asset Deduction - PARTS Deferred Costs**	12, 17	-	-	0.0	36.8	36.8
19	**Regulatory Asset Deduction - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	6, 13, 16	7.0	-	7.0	(3.4)	3.6
20	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	6, 14	1.0	-	1.0	1.0	2.0
21	**Other**	7, 9, 17	17.0	(7.5)	9.5	(3.8)	5.7
22	**Total Deductions**		1,317.0	(330.4)	986.6	(358.8)	627.8
23	**Regulatory Taxable Income**		163.0	3.4	166.4	(47.2)	119.2
24	**Income Tax Rate**		31.50%		31.50%		31.50%
25	**Regulatory Income Taxes**		51.3		52.4		37.5

Notes:

1 Full year amounts for 2008 as filed in EB-2007-0905, Ex F3-T2-S1, Table 7, Column (b), reproduced as Attachment 2 to EB-2010-0008, Ex. F4-T2-S1. Amounts are not adjusted for OEB findings in EB-2007-0905.

2 Amounts in col. (c) are 3/4ths of the full year 2008 balances in col. (a) with the exception of the items discussed in the notes below. Amounts are not adjusted for OEB findings in EB-2007-0905.

3 Details of the 2008 first quarter adjustment amount of $79M were provided EB-2007-0905, Undertaking Response Ex J9.4.

4 Depreciation expense in column (c) is derived as follows ($M):

2008 annual amount per EB-2007-0905 Ex. F3-T2-S1, Table 7, Line 3. Column b)	408.0
Add: Budgeted amount for depreciation deferred in the Nuclear Liability Deferral Account for Q1 2008	14.0
Adjusted annual amount	422.0
Adjusted annual amount x 3/4	316.5

5 To arrive at column (c) amount, column (a) amount is reduced by Q1 2008 budget amount of $27.4M.

6 No recovery of deferral/variance accounts were forecast for Q1 2008; therefore the amortization amount is all related to the Apr 1 to Dec 31, 2008 period only.

7 Other deductions for tax purposes for April 1, 2008 to December 31, 2008 to arrive at col. (c) are derived as follows ($M):

2008 annual amount per EB-2007-0905 Ex. F3-T2-S1, Table 7, Line 21, Column (b)	17.0
Remove budgeted amount for variance account additions during Q1 2008	(4.3)
Adjusted annual amount	12.7
Adjusted annual amount x 3/4	9.5

8 Refer to L-01-119 part (a) in EB-2010-0008 for calcuation of regulatory earnings before tax in column (e).

9

Removal of Bruce Lease Revenues and Costs from col. (c) to arrive at col. (e) (consistent with OEB's findings in EB-2007-0905)	2008 Full Year	Apr 1-Dec 31 (2008 Full Year x 3/4)
Depreciation, full year 2008: Payment Amounts Order, App A, Table 7, line 4, column (c)	(69.8)	(52.4)
Waste Mgmt, full year 2008: Payment Amounts Order, App A, Table 7, line 7. column (c)	(14.1)	(10.6)
Receipts from Nuclear Segregated Funds	(15.0)	(11.3)
Other Additions	(2.0)	(1.5)
CCA	(9.0)	(6.8)
Cash Expenditures For Nuclear Waste and Decommissioning, full year 2008: EB-2007-0905, Ex J1.5	(129.0)	(96.8)
Contributions to Nuclear Segregated Funds	(381.0)	(285.8)
Other Deductions	(5.0)	(3.8)

10 Reduced PARTS Recovery period prescribed by the OEB increases amortization expense in col (e): Payment Amounts Order, App A, Table 2a, Note 5

11 Remove recovery of refurbishment costs incurred prior to April 1, 2008 to arrive at col (e): Payment Amounts Order, App A, Table 2a, Note 5

12 The PARTS cost deduction/recovery in payment amounts over the test period is $85.8M per Payment Amounts Order App D, Line 1, Column f) pro-rated on a monthly basis:
9 months / 21 months = $85.8M * 9/21 = $36.8M

13 The nuclear development and capacity refurbishment cost tax deduction is adjusted to reflect the recovery of these costs at Line 7.
Interest of $1M was being recovered from customers during 2008. This amount was not originally reflected in the tax deduction in EB-2007-0905. As ratepayers bear the cost of this interest expense, the tax deduction in col. (e) has been increased in accordance with the "benefits follow costs" principle.

14 Adjusted in col. (d) to reflect the recovery of a portion of previously accrued interest on the outstanding balance of the nuclear liability deferral account in the amount of $1.0M in 2008 ($3.5M per EB-2007-0905 Ex. J1-T1-S1, Page 12, Chart 2--total interest is recovered over 33 months).
An adjustment is made to reflect the tax benefit of the deduction for the deferred interest accruing to consumers, in accordance with the EB-2007-0905 Decision With Reasons finding at Page 170 that states: "the party who bears a cost should be entitled to any related tax savings or benefits."

15 The OEB determined that OPG's nuclear liabilities would be reflected in the capital structure at OPG's average accreation rate. This deduction is effectively included in the segregated fund contributions and therefore is removed to avoid double-counting the adjustment. The duplicate interest adjustment is replaced in column (e) by the financing cost allowed by the OEB for OPG's unfunded nuclear liabilities per Payment Amounts Order, App. A, Table 5b, Line 7.
The Adjustment related to duplicate interest deduction and the adjustment related to financing cost for nuclear liabilities are described in Ex. F4-T2-S1, section 3.3.6.

16 For presentation purposes, amounts in Col. (e), Lines 7 and 19 are not shown in Ex. F4-T2-S1, Table 9 because they net to $nil

17 For presentation purposes, amounts in Col. (e), Lines 6, 18 and 21 are shown as a net figure of $6.9M in Ex. F4-T2-S1, Table 9, Col (a) , Line 17.

Board Staff Interrogatory #120

(NON-CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, page 10 - Tax Losses Prior to April 1, 2008

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

a) Please provide the T2 tax return Schedule 4 "Corporation Loss Continuity and Application" for each year from 1999 to 2007 for each company for which OPG provided tax returns on a confidential basis.

b) Please provide a summary of the losses incurred and applied in each year from 1999 to 2008 from the Schedule 4 documents provided in (a) above.

c) Please provide a reconciliation of tax return to regulatory similar to that provided in Table 12 for 2007 for each of 2008 and 2009 tax returns.

Response

Historical information for the period from 1999 to 2004 is not provided. The data from before 2005 is not relevant as OPG was not regulated prior to April 1, 2005.

a) The T2 tax return Schedule 4 "Corporation Loss Continuity and Application" for 2005 to 2007 for the companies included in the confidential tax returns previously filed with the OEB in this proceeding are included in a confidential submission accompanying this response (Attachment 1).

b) Included in Schedule 4 "Corporation Loss Continuity and Application" for each year per a) above is a Non-Capital Loss Continuity Workchart, which provides an analysis of the balance of losses by year of origin.

c) Attachment 2, Tables 1 (2008) and 2 (2009) reconcile the tax return to regulatory for 2008 and 2009 in a form similar to 2007 as filed in Ex. F4-T2-S1, Table 12. For 2009, the reconciliation includes two additional columns to reconcile from the tax return to the year-end tax provision and then, to revised regulatory. The revised regulatory calculation based on the 2009 tax return is provided and discussed in Ex. L-1-118.

Year 2008 - Reconciliation of Tax Return to Regulatory

		2008 Tax Return					Adjustments		
		1	2	3	4	5	6	7	8
Line No.	Particulars	OPG Parent	Subs	Total	UnReg	Regulated	Bruce	Other Adj.	Regulatory[1]
	Determination of Taxable Income								
1	Earnings Before Tax	314.4	(43.2)	271.2	(491.0)	(219.8)	283.3	(42.7)	20.8
2	Adj negative earnings to $0								-
3		314.4	(43.2)	271.2	(491.0)	(219.8)	283.3	(42.7)	20.8
	Additions for Tax Purposes:								
4	Depreciation	564.2	54.0	618.2	(201.0)	417.2	(61.1)	(5.2)	350.9
5	Nuclear Waste Management Expenses	646.5		646.5		646.5	(292.6)	(332.5)	21.4
6	Receipts from Nuclear Segregated Funds	81.5		81.5		81.5	(19.0)	-	62.5
7	Pension and OPEB/SPP Accrual	414.1		414.1	(88.8)	325.3		(0.5)	324.8
8	One-Time Adjustment: P2P3 Inventory Write-offs			-		-		-	-
9	One-Time Adjustment: P2P3 CIP Write-offs			-		-		-	-
10	Regulatory Asset Amortization - PARTS Deferred Costs	66.5		66.5		66.5		(66.5)	-
11	Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance	3.2		3.2		3.2		(3.2)	-
12	Regulatory Asset Amortization - Nucl Liability Deferral	35.6		35.6		35.6		-	35.6
13	First Nations Past Grievances Provision			-		-		-	-
14	Adjustment Related to Duplicate Interest Deduction (Q1 2008)			-		-		10.0	10.0
15	Adjustment related to Financing Cost for Nuclear Liabilities					-		53.9	53.9
16	Lennox impairment			-		-		-	-
17	Other	173.7	2.7	176.4	(52.4)	124.0	(2.0)	(80.5)	41.5
18	Total Additions	1,985.3	56.7	2,042.0	(342.2)	1,699.8	(374.7)	(424.5)	900.6
	Deductions for Tax Purposes:								
19	CCA	528.7	8.9	537.6	(229.7)	307.9	(9.1)	(0.0)	298.8
20	Cash Expenditures for Nuclear Waste & Decommissioning	195.0		195.0		195.0	(72.4)	-	122.6
21	Contributions to Nuclear Segregated Funds and Earnings	27.9		27.9		27.9	(211.1)	242.1	58.9
22	Pension Plan Contributions	253.0		253.0	(54.0)	199.0	-	(0.4)	198.6
23	OPEB/SPP Payments	81.0		81.0	(17.0)	64.0	-	(0.4)	63.6
24	Regulatory Asset Deduction - PARTS Deferred Costs	6.3		6.3		6.3		(6.3)	-
25	Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance	-		-		-	-	-	-
26	Regulatory Asset Amortization - Nucl Liability Deferral	-		-		-	-	1.8	1.8
27	Reversal of Bruce Regulatory Asset	354.7		354.7	-	354.7		(354.7)	-
28	SR&ED Qualifying Capital Expenditures	25.7		25.7	(9.0)	16.7		0.1	16.8
29	SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax	30.0		30.0	(1.7)	28.3		-	28.3
30	Construction In Progress Interest Capitalized	56.2		56.2	(25.0)	31.2		(31.2)	-
31	Other	110.8	2.6	113.4	(28.6)	84.8	(13.7)	(59.4)	11.7
32	Total Deductions	1,669.3	11.5	1,680.8	(365.0)	1,315.8	(306.3)	(208.4)	801.1
33	Net Income/(Loss) for income tax purposes	630.4	2.0	632.4	(468.2)	164.2	214.9	(258.7)	120.4
	Deduct:								
34	Charitable donations	8.6	-	8.6	(5.0)	3.6	-	(0.1)	3.5
35	Taxable Income	621.8	2.0	623.8	(463.2)	160.6	214.9	(258.6)	116.9

Notes:

1 Regulatory as per pre-filed evidence Ex. F4-T2-S1, Table 6.

Year 2009 - Reconciliation of Tax Return to Regulatory

		2009 Tax Return					Adjustment					
		1	2	3	4	5	6	7	8	9	10	11
Line No.	Particulars	OPG Parent	Subs	Total	UnReg	Regulated	Return to Provision Adj	Bruce	Other Adj	Regulatory[1]	Regulatory Provision to Return Adj	Revised Regulatory[2]
	Determination of Taxable Income											
1	Earnings Before Tax	807.3	(39.1)	768.2	(97.7)	670.5	-	(42.7)	(370.5)	257.3		257.3
2	Adj negative earnings to $0								-	-	-	-
3		807.3	(39.1)	768.2	(97.7)	670.5	-	(42.7)	(370.5)	257.3	-	257.3
	Additions for Tax Purposes:											
4	Depreciation	564.1	53.6	617.7	(177.7)	440.0	-	(60.4)	0.0	379.6		379.6
5	Nuclear Waste Management Expenses	666.2	-	666.2	-	666.2	(0.4)	(296.8)	(346.3)	22.7		22.7
6	Receipts from Nuclear Segregated Funds	103.9	-	103.9	-	103.9	-	(38.2)	-	65.7		65.7
7	Pension and OPEB/SPP Accrual	247.7	-	247.7	(54.4)	193.3	-		0.0	193.3		193.3
8	Regulatory Asset Amortization - PARTS Deferred Costs	43.3		43.3		43.3	-		(43.3)	-		-
9	Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance	4.3		4.3		4.3	(0.1)		(4.2)	-		-
10	Regulatory Asset Amortization - Nucl Liability Deferral	47.5		47.5		47.5	(0.1)		0.1	47.5		47.5
11	Reversal of Amounts Recorded in Income and Other Taxes Variance Account	17.0		17.0		17.0	-		-	17.0		17.0
12	Adjustment Related to Financing Cost for Nuclear Liabilities	-		-		-	-		65.0	65.0		65.0
13	Taxable SR&ED Investment Tax Credits of Prior Periods	55.9		55.9	(18.0)	37.9	-		-	37.9		37.9
14	Other	331.6	7.9	339.6	(38.7)	300.8	5.4	(151.1)	(95.6)	59.5	1.6	61.1
15	Total Additions	2,081.5	61.5	2,143.1	(288.8)	1,854.2	4.8	(546.5)	(424.3)	888.2	1.6	889.8
	Deductions for Tax Purposes:											
16	CCA	516.1	8.0	524.1	(221.8)	302.3	1.1	(8.2)	(0.0)	295.2	(1.1)	294.1
17	Cash Expenditures for Nuclear Waste & Decommissioning	191.2		191.2	-	191.2	-	(62.0)	0.1	129.3		129.3
18	Contributions to Nuclear Segregated Funds and Earnings	1,140.5		1,140.5	-	1,140.5	-	(600.3)	(415.5)	124.7		124.7
19	Pension Plan Contributions	269.1		269.1	(57.9)	211.2	(6.0)		(0.1)	205.1	6.0	211.1
20	OPEB/SPP Payments	79.5		79.5	(17.8)	61.7	0.1		(0.0)	61.8		61.8
21	Regulatory Asset Deduction - PARTS Deferred Costs	1.4		1.4		1.4	(0.4)		(1.0)	-		-
22	Regulatory Asset Amortization - Nucl Liability Deferral	-		-		-	-		2.4	2.4		2.4
23	Reversal of Bruce Regulatory Asset	104.0		104.0	-	104.0	(0.1)		(103.9)	-		-
24	Tax Loss Revenue & Interest	295.0		295.0	-	295.0	(0.1)		(294.9)	-		-
25	SR&ED Qualifying Capital Expenditures	-		-		-	-		-	-		-
26	SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax	22.1		22.1	(2.8)	19.3	-		-	19.3		19.3
27	Construction in Progress Interest Capitalized	57.7		57.7	(16.1)	41.6	-		(41.6)	-		-
28	Other	48.0	12.5	60.5	(22.7)	37.8	(0.6)	(11.8)	(23.3)	2.1		2.1
29	Total Deductions	2,724.6	20.5	2,745.1	(339.1)	2,406.0	(6.0)	(682.3)	(877.8)	839.9	4.9	844.8
30	Net Income/(Loss) for income tax purposes	164.2	1.9	166.1	(47.4)	118.7	10.8	93.1	83.0	305.6	(3.3)	302.3
	Deduct:											
31	Charitable donations	3.1		3.1	(3.1)	-						
32	Taxable Income	161.1	1.9	163.0	(44.3)	118.7	10.8	93.1	83.0	305.6	(3.3)	302.3

Notes:
1 Regulatory as per pre-filed evidence Ex. F4-T2-S1, Table 6.
2 Revised regulatory as filed in Ex. L-T01-S118, Table 1.

I:\OEB APPLICATION\Grace_Admin Folder\IR ATTACHMENTS_Recd from PC\IR Attachments\Original Format_not pdf\L-01-120_Attachment 2, Tables 1 and 2 Table 2

CME Interrogatory #030

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 10.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Please indicate, year by year, the amounts for taxes in each of the years 2005 to 2009, inclusive, that OPG now seeks to recover through the Tax Loss Variance Account?

Response

The Tax Loss Variance Account was established by the OEB in EB-2009-0038 effective April 1, 2008, and as such no entries were made into the account pertaining to the period prior to that date.

OPG notes that only a portion of the Tax Loss Variance Account pertains to taxes. The entries in the account represent the difference between the revenue requirement reduction inappropriately imposed by the OEB in EB-2007-0905 and the amount of mitigation that is available in the form of regulatory tax losses for the period from April 1, 2005 – March 31, 2008. The non-tax portion for 2008 – 2009 is $168.7M (Ex. H1-T1-S1, page 7), which represents the revenue requirement reduction of 22 per cent of the revenue deficiency ordered by the OEB in EB-2007-0905.

The tax portion consists of:

- The recovery of foregone regulatory income taxes (grossed-up, as discussed in Ex. L-1-144) that were inappropriately excluded in the calculation of the approved revenue requirement in EB-2007-0905 less the reduction in these taxes (grossed-up, as discussed in Ex. L-1-144) resulting from the carry-forward of recalculated regulatory tax losses.

- The additional regulatory income taxes (grossed up, as discussed in Ex. L-1-144) that would have arisen had the revenue requirement not been inappropriately reduced by $168.7M discussed above.

The amount of taxes for each of the years 2008 and 2009 pertaining to item #1 above is computed as follows:

April 1, 2008 – December 31, 2008: $33.1M (A)
(Foregone taxes + associated gross-up = $54.7M per Ex. L-1-117, Table 1, Note 2, line 2. $54.7M less 9/21 x $50.3M (Ex. H1-T1-S1, page 7 for recalculated tax losses) = $33.1M.)

January 1, 2009 – December 31, 2009: $12.6M (B)
(Foregone taxes + associated gross-up = $41.3M per Ex. L-1-117, Table 1, Note 2, line 2. $41.3M less 12/21 x $50.3M (Ex. H1-T1-S1, page 7 for recalculated tax losses) = $12.6M.)

The amount of taxes for each of the years 2008 and 2009 pertaining to item #2 above is as follows:

April 1, 2008 – December 31, 2008: $33.2M (A)
(Ex. L-1-117, Table 1, Note 2, line 4)

January 1, 2009 – December 31, 2009: $43.3M (B)
(Ex. L-1-117, Table 1, Note 2, line 4)

Therefore, the total amount of taxes that OPG seeks to recovery for 2008 and 2009 through the operation of the Tax Loss Variance Account is as follows:

April 1, 2008 – December 31, 2008: $66.3M (Sum of (A))

January 1, 2009 – December 31, 2009: $55.9M (Sum of (B))

Numbers may not add due to rounding.

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - 2007 to March 2008 ($M)

Line No.	Account	Year End Balance 2007[1]	First Quarter 2008			Balance March 2008
			Transactions	Amortization	Interest	
		(a)	(b)	(c)	(d)	(e)
	Regulated Hydroelectric:					
1	**Hydroelectric Water Conditions Variance**	6.3	1.7	0.0	0.1	8.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	7.2	(0.5)	0.0	0.1	6.8
3	**Income and Other Taxes Variance**	0.0	0.0	0.0	0.0	0.0
4	**Tax Loss Variance**	0.0	0.0	0.0	0.0	0.0
5	**Interim Period Shortfall (Rider D)**	0.0	0.0	0.0	0.0	0.0
6	**Over/Under Recovery Variance - (2010)**	0.0	0.0	0.0	0.0	0.0
7	**Total**	13.5	1.1	0.0	0.2	14.8
	Nuclear:					
8	**Pickering A Return To Service Deferral**	183.8	0.0	(24.1)	2.6	162.3
9	**Nuclear Liability Deferral**	130.5	31.3	0.0	2.1	163.9
10	**Nuclear Development Variance**	11.7	3.8	0.0	0.2	15.6
11	**Transmission Outages and Restrictions Variance**	1.8	0.0	0.0	0.0	1.8
12	**Ancillary Services Net Revenue Variance - Nuclear**	(1.8)	(0.2)	0.0	(0.0)	(2.1)
13	**Capacity Refurbishment Variance**	0.0	0.0	0.0	0.0	0.0
14	**Nuclear Fuel Cost Variance**	0.0	0.0	0.0	0.0	0.0
15	**Bruce Lease Net Revenues Variance**	0.0	0.0	0.0	0.0	0.0
16	**Income and other Taxes Variance**	0.0	0.0	0.0	0.0	0.0
17	**Tax Loss Variance**	0.0	0.0	0.0	0.0	0.0
18	**Interim Period Shortfall (Rider B)**	0.0	0.0	0.0	0.0	0.0
19	**Over/Under Recovery Variance - Nuclear (Rider A&C)**	0.0	0.0	0.0	0.0	0.0
20	**Over/Under Recovery Variance - (2010)**	0.0	0.0	0.0	0.0	0.0
21	**Total**	325.9	34.8	(24.1)	4.9	341.6
22	**Grand Total**	339.4	36.0	(24.1)	5.2	356.4

Notes:

1 2007 balances are as approved by OEB in Payment Order EB-2007-0905 with the exception of Hydroelectric Water Conditions, Ancillary Services Net Revenue-Hydroelectric, Transmission Outages and Restrictions and Ancillary Services Net Revenue-Nuclear variance accounts. The individual balances provided for these four accounts by OPG in EB-2007-0905 were not correct, but the total balance for all four accounts is correct. OPG is proposing to correct the individual account balances as part of this Application. There is no financial impact of making this correction as the errors in the individual accounts are offsetting.

Numbers may not add due to rounding.

Table 10
Bruce Lease Net Revenue
Summary Calculation of Year End Account Balances - 2008 to 2010

Line No.	Account	2008	2009	2010
		(a)	(b)	(c)
1	**Actual Lease Net Revenue[1] ($M)**	(179.9)	37.4	115.0
	Reference Plan:			
2	**Lease Net Revenue - Apr 08-Dec 2009 ($M)**	191.9	191.9	191.9
3	**Production - Apr 08-Dec 2009 (TWh)**	88.2	88.2	88.2
4	**Rate Credited to Customers per Payment Order EB-2007-0905 ($/MWh)**	2.18	2.18	2.18
5	**Actual Production (TWh)**	35.6	47.6	46.2
6	**Amount Credited to Customers in Payment Order EB-2007-0905 ($M)**	77.5	103.7	100.5
	(line 4 x line 5)			
7	**Lease Net Revenue Variance ($M)** (line 6 - line 1)	257.4	66.3	(14.3)

1 See Ex. H1-T1-S1 Table 10a for derivation.

Numbers may not add due to rounding.

Table 10a
Bruce Lease Net Revenue Variance Account
Calculation of Bruce Lease Net Revenue - Actual 2008 and 2009 and Projected 2010

Line No.	Account	Jan 1 - Mar 31 2008	Apr 1 - Dec 31 2008	2008	2009	2010
	Revenue[1]:					
1	**Lease Revenue**	58.0	200.1	258.1	41.4	234.3
2	**Services Revenue**	9.1	1.3	10.4	7.3	12.4
3	**Total Bruce Revenue**	67.1	201.4	268.5	48.7	246.6
	Costs[2]:					
4	**Depreciation**	12.6	48.4	61.0	60.4	34.5
5	**Property Tax**	(13.1)	12.1	(1.0)	12.9	13.1
6	**Capital Tax**	0.9	2.7	3.6	3.4	1.1
7	**Accretion**	66.7	200.7	267.4	279.3	282.4
8	**(Earnings) Losses on Segregated Funds**	21.8	162.2	183.9	(386.2)	(268.8)
9	**Used Fuel Storage and Disposal**	3.2	10.8	14.0	14.4	16.7
10	**Waste Management Variable Expenses**	3.6	0.0	3.6	3.1	0.9
11	**Interest**	4.8	14.5	19.3	18.7	13.2
12	**Income Tax**	(0.1)	(70.1)	(70.1)	5.3	38.6
13	**Total Costs**	100.4	381.2	481.7	11.3	131.7
14	**Bruce Lease Net Revenue** (line 3 - line 13)	(33.3)	(179.9)	(213.2)	37.4	115.0

Notes:
1 Ex G2-T2-S1 Table 2 for 2008, 2009 and 2010.
2 Ex G2-T2-S1 Table 5 for 2008, 2009 and 2010.