VECC Interrogatory #001

Ref: Ex. A2-T2-S1, Attachment 1, page 11, 2010 Business Plan Instructions

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

Interrogatory

a) The evidence states that *"Interest capitalization rates are assumed to be 6% for the business planning horizon."*

   Please indicate how this 6% figure was chosen.

b) Please provide the assumed interest capitalization rate in the previous business plan. If different, please explain why.

c) Please provide the impact on the revenue requirement in 2011 and 2012 of a 1% change in this assumption (i) under OPG's CWIP proposal and (ii) assuming the CWIP proposal is rejected.

Response

a) Interest capitalization rate of six per cent reflects an approximation of OPG's overall borrowing rate based on the interest rate on its long-term debt. This interest capitalization rate is monitored regularly against OPG's outstanding debt to ensure that the rate remains reasonable.

b) The interest capitalization rate in the previous business plan was six per cent.

c) A change in the interest capitalization rate will not impact the 2011 - 2012 revenue requirement whether or not OPG's Construction Work in Progress ("CWIP") in rate base proposal is accepted. If the proposal is accepted, CWIP will be included in rate base and no interest will be capitalized on CWIP. If OPG's proposal is rejected, then capitalized interest will accrue, but will not impact the revenue requirement until the project is closed to rate base, which will not occur in 2011 - 2012.

   Based on forecast in-service additions during the test period, OPG estimates that a change of +/-1 per cent in the interest capitalization rate, beginning 2011, would increase/decrease the regulated rate base by approximately $6M by the end of 2012. This would impact the revenue requirement by approximately $1M for the 2011 - 2012 period.

VECC Interrogatory #002

Ref: Ex. A2-T2-S1, page 7

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2011 - 2012 an appropriate basis on which to set payment amounts?

Interrogatory

a) The capitalization decision tree indicates that even if expenditure does not provide future benefits for more than one year, it will be capitalized if the expenditure exceeds materiality limits. Please indicate why this is appropriate and explain in such cases how depreciation expense is calculated.

b) Please provide a list of all expenditures that OPG proposes to capitalize over the test period which will provide future benefits for a period of less than one year.

Response

a) The question is based on an incorrect interpretation of the capitalization decision tree. OPG's capitalization policy provides that expenditures that do not provide benefits exceeding one year are recorded as OM&A expense and are ***not*** capitalized. This is specifically noted in Ex. A2-T2-S1, page 5, lines 22-31 and page 6, lines 1-3.

b) See response in a) above. Expenditures that do not provide future benefits for more than one year are expensed as incurred.

VECC Interrogatory #003

Ref: Ex. B1-T1, page 3, Forecast Methodology

Issue Number: 2.1
Issue: What is the appropriate amount for rate base?

Interrogatory

For each year for which actual values are available, please provide the forecasted and actual rate bases for the regulated hydroelectric facilities and for the regulated nuclear fleet. Please provide variance explanations in all cases where there is a material difference between forecasted and actual rate base.

Response

Please see the response to Interrogatory L-1-002, which includes a comparison of forecasted (OEB approved) rate base to actual rate base for the years 2008 and 2009.

As indicated in that response, the variances in rate base for those years are not significant.

- The hydroelectric rate base variances are less than one per cent in each year.

- The nuclear rate base variance is in the one – two per cent range each year, and is a combination of small variances in net plant and fuel inventories.

VECC Interrogatory #005

Ref: Ex. C1-T1-S2, pages 10 and 11

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

On pages 10 and 11 OPG describes how, for the deemed debt component of its capital structure it applies the Board's deemed long-term debt rate, and that for the purposes of the application that rate is 5.87%, but that OPG proposes that that rate be updated at the time of the final rate order.

a) Please calculate the revenue requirement impact (for each test year) of applying the weighted average cost of OPG's actual long-term debt to the deemed long-term debt. (With reference to Exhibit C1, Tab 1, Schedule 1, tables 1 and 2, VECC believes that the calculation begins with applying a rate of 5.5% to the Other Long-Term Debt of $877.7M in 2012 and a rate of 5.53% to the Other Long-Term Debt of $725.2M in 2011) VECC is aware that Board Staff IR 15 b) asks a similar question, although VECC is seeking the full revenue requirement impact of the change, plus VECC would like an additional calculation performed and included in the same response; see the requested second calculation in part b) of this IR.

b) Please calculate the revenue requirement impact for (each test year) of applying the weighted average cost of its actual debt (both long-term and short-term) to the deemed long-term debt. (With reference to Exhibit C1, Tab 1, Schedule 1, Tables 1 and 2, VECC believes that the calculation begins with applying the weighted average cost rate of rows 1 and 2 in Table 1 and applying it to the Other Long-Term Debt of $877.7M in 2012, and applying the weighted average cost rate of rows 1 and 2 in Table 2 and applying it to the Other Long-Term Debt in 2011 of $725M in 2011).

Response

a) OPG's Other Long-Term Debt Provision amounts for 2011 and 2012 are $877.7M and $725.2M, respectively, as opposed to $725.2M and $877.7M as cited in the question.

The response in Ex. L-1-015 calculates the revised interest expense for the Other Long-Term Debt Provision at $39.9M in 2012 and $48.5M in 2011. The corresponding costs at the deemed debt rate are $42.6M in 2012 and $51.5M in 2011 as shown in Ex. C1-T1-S1, Table 1 (2012) and Table 2 (2011). The lower interest expense results in higher taxable income and higher income tax calculated at the rate of 25 per cent in 2012 and

26.5 per cent in 2011 (Ex. F4-T2-S1, Table 5). The total revenue requirement impact is summarized below:

Revenue Requirement Component	2011 ($M)	2012 ($M)	2011 – 2012 ($M)
Lower Interest Expense	(3.0)	(2.7)	(5.7)
Higher Income Taxes	0.8	0.7	1.5
Total Revenue Requirement Impact	(2.2)	(2.0)	(4.2)

b) The impact on the revenue requirement in 2012 of replacing the deemed debt cost with the weighted average cost of all existing/planned debt for the Other Long-Term Debt is the same as in part a) as this weighted average rate is also 5.50 per cent as shown below.

Capital Structure Component	Principal ($M)	Cost Rate (%)	Cost ($M)
Short-Term Debt	189.5	4.13	10.4
Existing/Planned Long-Term Debt	2,502.8	5.50	137.6
Total Actual Debt	2,692.3	5.50	148.1

The impact on the revenue requirement in 2011 of replacing the deemed debt cost with the weighted average cost of all existing/planned debt for the Other Long-Term Debt is slightly higher ($0.7M) than in part a) as the weighted average rate falls from 5.53 per cent in part a) to 5.41 per cent as shown below.

Capital Structure Component	Principal ($M)	Cost Rate (%)	Cost ($M)
Short-Term Debt	189.5	2.64	7.6
Existing/Planned Long-Term Debt	2,283.1	5.53	126.2
Total Actual Debt	2,472.6	5.41	133.7

At a rate of 5.41 per cent the Other Long-Term Debt Provision of $877.7M for 2011 results in a cost of debt of $47.5M, versus the $51.5M in Ex. C1-T1-S1, Table 2. The total revenue requirement impact is summarized below:

Revenue Requirement Component	2011 ($M)	2012 ($M)	2011 – 2012 ($M)
Lower Interest Expense	(4.0)	(2.7)	(6.7)
Higher Income Taxes	1.1	0.7	1.8
Total Revenue Requirement Impact	(2.9)	(2.0)	(4.9)

VECC Interrogatory #006

Ref: Ex. D1-T1-S1, page 5 and Table 2, Ex. D1-T1-S2, Attachment 1, page 1, and Ex. D1-T1-S2, page 3, lines 1-2

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

With respect to the Niagara Tunnel Project, the pre-filed evidence states:

> *In June 2009, following the recommendations of the Dispute Review Board ("DRB"), OPG and the contractor signed an amended design-build contract with a revised target cost and schedule. The target cost and schedule took into account the difficult rock conditions encountered, restoration of the circular cross section in areas of rock overbreak, and the concurrent tunnel excavation and liner installation work required to expedite completion of the tunnel. OPG's Board of Directors approved a revised project cost estimate of $1.6B and a revised scheduled completion date of December 2013.*

The last reference above states:

> *The Niagara Tunnel project was originally approved by OPG's Board of Directors ("the OPG Board") in July 2005 at an estimated cost of $985M and a June 2010 in-service date.*

Please provide the annual capital spending originally planned for this project for each year until completion, i.e., the original estimated yearly capital expenditures before the Board of Directors approved the revised project estimate of $1.6B.

Response

Originally planned capital expenditures for this project from the Niagara Tunnel Project business case summary, dated July 28, 2005, were:

2004	$3.5M
2005	$69.2M
2006	$194.1M
2007	$215.5M
2008	$227.7M
2009	$208.9M
2010	$66.3M
Total	$985.2M

VECC Interrogatory #007

Ref: Ex. E1-T1-S2
Ex. E1-T1-S2, Table 1

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

For 2007-2009 inclusive, although budgeted production was significantly less than actual production, the imputed production (using ex post actual water flows in the forecast model) was very close to actual for these years.

a) Has OPG investigated whether there is some systematic bias in its forecasted water flows?

b) To what extent has/can OPG improve its water flow assumptions used in its forecasting model?

c) Do OPG's actions in operating its hydroelectric facilities materially affect the water flows used ex post for the imputed production levels?

Response

a) See the response to Interrogatory L-04-023.

b) See the response to Interrogatory L-04-023.

c) No, the water flows used for the imputed production values are a result of natural hydrology.

VECC Interrogatory #008

Ref: Ex F2-T1-S1, Attachment 1 page 6, Nuclear Business Plan 2010 - 014 – Board of Directors

Issue Number: 6.4
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

Interrogatory

Please provide the Best Quartile and Median metrics in the first row for All Injury Rate.

Response

The confidential version of Ex F2-T1-S1, Attachment 1, page 6 contains the available information.

VECC Interrogatory #010

Ref: Ex. F1-T1-S1, page 5

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

a) Please provide a simple worked example to show how the EFOR index is calculated.

b) Please confirm that the accident severity rate is defined as the number of days lost by employees injured on the job per 200,000 hours worked.

Response

a) The Equivalent Forced Outage Rate ("EFOR") shows the rate (in per cent) that a unit is not available due to forced events. Forced events are unplanned events that require a unit to be removed from service, in whole or in part.

   A simple worked example is provided below for a generator which during a given year spent the following amounts of time in the following states:
   - Service Hours (Operating) – 5,000 hrs
   - Reserve Shutdown (Available but not Operating) – 1,760 hrs
   - Forced outages – 250 hrs
   - Planned or Maintenance outages – 1,750 hrs
   - (The total hours per year is 8,760)

   If there are no deratings (see discussion below), the EFOR for the above example would be equal to 250 divided by the sum of 250 and 5,000 which is 4.76 per cent.

   A derating is when a unit is only partially available: for example, a 100 MW unit that can only generate 80 MW of power. In such a case, additional forced derate time is added to the equivalent forced outage time. For this example, a 5 day derating on an operating unit would count as one equivalent outage day (i.e., 5 days times 20 per cent derating). This equivalent outage day (24 hours) would be added to the forced outage hours (in the numerator) in the simple example above.

   A derating can also occur during Reserve Shutdown hours. In the case of a derating during reserve shutdown, the 100 MW unit derated to 80 MW for five days while available but not operating would have the equivalent 24 outage hours added to both the forced outage hours (in the numerator) and the service hours (in the denominator) in the above simple example of EFOR.

The EFOR calculation methodology is defined in the Generating Availability Data System Reporting Instructions issued by the North American Reliability Council (“NERC”).

b) Confirmed.

VECC Interrogatory #011

Ref: Ex. F1-T1-S1, pages 5, 10, and 11

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

Please provide specific details regarding the construction of the environmental performance index.

Response

The Environmental Performance Index ("EPI") is described in Ex. F1-T1-S1, pages 5, 10, and 11. The EPI is normally produced annually at the plant group level. The components of the EPI target are shown in the sample calculation below, which is representative of the components in an actual index.

2010 Environmental Performance Index (EPI) – Sample Calculation

Category	Performance Measure	Threshold (0.5)	Target (1.0)	Max. (1.5)	Weighting (%)	Actual	Score
Spills	Category A Spill	0	0	0	Meet	0	Meet
	Category B Spill	0	0	0	Meet	0	Meet
	Category C Spill	2	1	0	25%	1	25%
Regulatory Compliance	Major Regulatory Infractions	0	0	0	Meet	0	Meet
	Moderate Regulatory Infractions	2	1	0	35%	0	53%
Internal Energy Efficiency (IEE)	Energy Efficiency Projects Completed	1 runner upgrade	1 runner upgrade; 1 transformer replacement	2 runner upgrades; 1 transformer replacement	40%	1 runner upgrade	20%
TOTAL					**100%**		**98%**

VECC Interrogatory #012

Ref: Ex. F1-T1-S1, pages 6 and 7, and Chart 1

Issue Number: 6.2

Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

Regarding the EFOR targets and actual as shown on Chart 1, please provide the comparable CEA and EUCG average and median results for 2007, 2008, and 2009. Also, please explain how the targets for future years are set.

Response

The comparable results are presented in the tables below. The 2009 data from Canadian Electrical Association ("CEA") and Electric Utility Cost Group ("EUCG") is not currently available.

Table 1
Average Equivalent Forced Outage Rate (%)

Name of Station/Grouping	2007	2008	2009
CEA Excluding OPG	3.25	N/A	N/A
EUCG Excluding OPG	5.77	6.17	N/A
OPG	1.80	1.50	1.00

Table 2
Median Equivalent Forced Outage Rate (%)

Name of Station/Grouping	2007	2008	2009
CEA Excluding OPG	Not Available (CEA may make it available in 2011)		
EUCG Excluding OPG (median by plant, ~210 plants)	0.61	0.85	N/A
OPG (median by unit, 5 regulated plants = 49 units)[1]	0.03	0.02	0.01

[1] The sample of OPG five regulated plants is statistically insufficiently representative to calculate the median by plant.

In general, Equivalent Forced Outage Rate (“EFOR”) targets are set based on plant historical performance. An average EFOR is calculated for the last ten years after rejecting the two most extreme numbers (i.e., minimum and maximum years) leaving eight data points. Continuous improvement or other factors may be added to the targets subject to the discretion of the Executive Management Team. However, since recent EFOR targets have been at historical lows, they have received little or no adjustment.

VECC Interrogatory #013

Ref: Ex. F5-T1-S2, pages 29-30, Figure 15

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

For each one of the Recommendations provided by ScottMadden shown in this figure, please indicate whether OPG intends to adopt it or not. For those that OPG does not intend to adopt, please provide reasons.

Response

Figure 15 at Ex. F5-T1-S2, pages 29-30 sets out various recommendations on organization structure. OPG's response to these recommendations is set out below:

RECOMMENDATION	OPG RESPONSE
Clear Accountability for Results • OPG demonstrates alignment with principle of the clear responsibility. • Accountability for certain nuclear oversight functions should be clarified and documented using the GOSP framework.	• The first "recommendation" is an observation, which confirms that "OPG demonstrates alignment with the principle of clear responsibility." • OPG adopts the second recommendation. OPG is reviewing the GOSP framework for the reasons set out below under "Adoption of the GOSP Model".
Station-Based Accountability • OPG demonstrates alignment with principle of the "station-based accountability.	• This "recommendation" is also an observation, which confirms that "OPG demonstrates alignment with the principle of station-based accountability".
A Strong Plant Manager Focus • Consider adopting a single Plant Manager model in lieu of the current dual DOM/DWM roles.	• OPG's position on both these recommendations is set out in Ex. L-1-059.

• In light of the change required by the 33 fleet improvement initiatives, it might be best to postpone implementation of this recommendation until 2012 or beyond.	
Adoption of the GOSP Model • Adopt the GOSP model and clearly identify all plant functions in their appropriate designation (*govern, oversee, support, perform*). • Ensure that managers, supervisors and employees are training in the GOSP concept and appreciate the respective roles and responsibilities.	• OPG is reviewing the GOSP model. As ScottMadden notes in its report, there are several governance frameworks used by leading nuclear fleet operators to help clarify accountabilities. OPG has a well defined governance program in place as confirmed by ScottMadden. OPG intends to continuously improve its governance framework (e.g., by improving accountability for nuclear oversight) and it will consider the GOSP model in that context.
Organization Structured Around Business Needs not Employee Capabilities	• ScottMadden did not provide any recommendations on this topic.
Fleet Standardization • Develop a “best practice” station organization and staffing model and then apply this model consistently across the fleet. • Examine and address the overly high spans of control in Engineering. • Standardize the organizational nomenclature used at the different sites. • Establish a process for identifying “best practices” across OPGN fleet and then rolling these out to all the stations.	• OPG adopts all four of these recommendations. Initiatives to implement them include addressing spans of control in Engineering as part of the En-02 Engineering Value for Money initiative, and improvements to the effectiveness of peer teams who are tasked with identifying opportunities for fleet wide initiatives (see Ex. L-14-016).

VECC Interrogatory #014

Ref: Ex. F5-T1-S2, pages 31-32

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please indicate OPG's views with respect to adopting the three benchmarking "Related Recommendations."

Response

OPG has adopted the three benchmarking "Related Recommendations" from Ex F5-T1-S2 pages 31-32 that are reproduced below.

1. Update the OPG Nuclear Benchmarking Report in 2010 using the procedure prepared by the joint ScottMadden/OPG team.

2. Begin this process as early as possible so that the results of the benchmarking analysis are available to the planning team for target setting early in the 2010 business planning cycle

3. Assign a single point of accountability for reporting OPG data to EUCG, WANO and other outside organizations. This will help improve data quality and consistency of presentation.

VECC Interrogatory #015

Ref: Ex. F5-T1-S2, page 32

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please provide OPG's views with respect to adopting the two target setting "Related Recommendations."

Response

OPG has adopted the two target setting "Related Recommendations" found on Ex. F5-T1-S2 page 32 and set out below:

1. When the OPG Nuclear Benchmarking Report is updated in 2010, analyze the new benchmarks and use them to establish operational and financial performance targets for 2015.

2. Through a process of continuous improvement, continue closing the gap to "best quartile" industry performance for all metrics and at all sites as additional years are added to the rolling five-year plan.

VECC Interrogatory #016

Ref: Ex. F5-T1-S2, page 34

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please provide OPG's views with respect to adopting the three fleet-wide improvement initiatives "Related Recommendations."

Response

OPG has adopted the three fleet-wide improvement initiatives "Related Recommendations" found on Ex F5-T1-S2, page 34, except for the expansion of the number of peer teams. OPG does not believe more peer teams will improve performance until changes are made in the way existing teams are managed. In that regard, OPG has revised peer team governance to ensure all levels of leadership are engaged in the improvement process. A director is now accountable to Nuclear Executive Committee ("NEC") and the Chief Nuclear Officer ("CNO") for peer team performance. Performance reporting has been revised to ensure consistency with US peers.

In addition, the role of certain peer teams has been augmented by the Nuclear Improvement Organization. For example, the days-based maintenance initiative now has a dedicated team lead managing the initiative on behalf of the maintenance peer team. This hybrid project structure ensures the initiative remains on track even when faced with obstacles, and helps maintenance managers remain focused on core business.

VECC Interrogatory #017

Ref: Ex. F5-T1-S2, page 35

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please provide OPG's views with respect to adopting the two site and support business unit plans "Related Recommendations."

Response

OPG has adopted the two site and support business unit benchmarking "Related Recommendations" found on Ex. F5-T1-S2, page 35 and set out below:

1. Incorporate gap-based business planning into the business planning processes for all subsequent years.

2. Begin the process early enough so that fleet-wide and site/support unit improvement initiatives are identified prior to the beginning of the summer vacation period.

VECC Interrogatory #018

Ref: Ex. F5-T1-S2, page 35

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please provide OPG's views with respect to adopting the two adoption of gap-based business planning "Related Recommendations."

Response

OPG has adopted the two gap-based business planning "Related Recommendations" found on Ex. F5-T1-S2, page 35 and set out below:

1. As noted earlier, incorporate gap-based business planning into the business planning process for all subsequent years.

2. Ensure ongoing reinforcement of senior management commitment through active communication and participation.

VECC Interrogatory #019

Ref: Ex. F5-T1-S2, pages 38-40

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Please provide OPG's views with respect to adopting the five plan execution and monitoring "Related Recommendations."

Response

OPG has adopted all of the five plan execution and monitoring "Related Recommendations" on Ex. F5-T1-S2, page 38-40.

Four of the recommendations are discussed in response to Interrogatory L-01-062. These are:

- At the program level, establish a formal organization structure to oversee and coordinate the high impact, most difficult improvement initiatives identified during the planning process.

- Assign a full-time senior executive to lead this organization.

- Establish a Program Management Office ("PMO") to support this executive.

- At the initiative level, adopt a "hybrid" project structure capable of leveraging the best elements of central guidance and support combined with significant line participation and decision making.

With respect to the fifth recommendation:

- Identify and utilize resources (internal and/or external) experienced in managing large organization transformation initiatives to help launch and provide initial support to the fleet improvement executive, the PMO organization, and the initiative teams.

OPG has hired an external consultant (ScottMadden) who is experienced in managing large organization transformation initiatives and who is providing initial support to the Senior Vice President Nuclear Programs and Training and the Director Nuclear Improvement.

VECC Interrogatory #020
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F2-T5-S1, page 7, Figure 1.0, and page 9, Chart 3

Issue Number: 6.6
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

a) Are the market-related prices for uranium concentrate simply the spot prices at the time of delivery? If not, please indicate exactly how market-related prices are determined.

b) For contracts B, C, and D, please provide a breakdown of the quantities subject to market related pricing and the quantities subject to indexation.

c) Please provide details as to how the prices are indexed, i.e., by a general index of inflation, by an index of commodity prices, etc.

d) Please provide details as to how OPG has hedged the price risk which is fully borne by ratepayers.

Response

a) The market-related price for uranium concentrate is not simply the spot price at the time of delivery. Market-related price is the price to be paid at the time of delivery, based on the average of published market price indicators for a specified period prior to delivery.

   The two most common price indicators used to establish the price paid at the time of delivery for OPG market-related contracts are the following:

   - The month-end U3O8 Long-Term Price Indicator (in United States dollars) per pound of uranium as U3O8, listed in The U_X Weekly published by The Ux Consulting Company LLC.

   - The month-end U3O8 Long-Term Price Indicator (in United States dollar) per pound of uranium as U3O8 listed in the Nuclear Market Review published by Trade Tech LLC.

   A combination of these indicators over different periods may also be utilized.

b) Provides the confidential breakdown of quantities subject to market pricing versus indexation for contracts B, C, and D.

c) Contracts utilizing indexed pricing (base price escalation) will have a fixed price component which is subject to price escalation over the term of the contract based on changes in either (Consumer Price Index ["CPI"] for Canada – all items) or US Gross Domestic Product implicit price deflator for the base period specified in the contract.

d) The underlying premise of this question is incorrect. The existence of the Nuclear Fuel Variance Account does not mean that the price risk is fully borne by ratepayers. If any of the costs in the variance account are found to be imprudent by the OEB, then OPG will not be able to recover these costs from ratepayers. It should also be noted that any cost decreases would be passed on to ratepayers.

OPG's uranium concentrate procurement strategy, as stated in Ex. F2-T5-S1, page 5, is to maintain a combination of uranium concentrate supply contracts and inventory which provide a minimum of 100 per cent of delivery requirements for two years and a declining proportion of delivery requirements for ten years. OPG maintains a portfolio of uranium concentrates supply contract arrangements, diversified by source, contract term, and pricing mechanism. This portfolio diversity aids in the hedging of price risk, reduces cost volatility, and enhances supply security.

VECC Interrogatory #021

Ref: Ex. F4-T3-S1, page 7, Chart 3

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Please provide similar charts for the years 2010, 2011, and 2012.

Response

The requested tables are provided below.

2010 created from 2009 adjusted base using escalation of 4,4,3

2010		PWU		Society		Management Group	
		Regular	Non-Regular[2]	Regular	Non-Regular[2]	Regular	Non-Regular[2]
Nuclear	**Total Wages**	**109.1**	**63.1**	**122.6**	**80.5**	**161.6**	**92.0**
	Base Salary[1]	81.5	42.9	100.5	56.3	131.1	79.4
	Overtime	18.0	11.8	15.7	10.5	0.9	0.0
	Incentives	2.5	0.1	3.4	2.0	18.6	7.6
	Other	7.1	8.3	2.9	11.8	10.9	4.9
	Benefits[4]	4.7	0.0	5.7	0.0	7.3	0.0
	Pension/OPEB[5]	12.6	0.0	15.3	0.0	19.7	0.0
Regulated Hydro	**Total Wages[3]**	**98.4**	**40.8**	**104.9**	**71.9**	**156.9**	**0.0**
	Base Salary[1]	84.6	35.8	95.6	68.5	125.6	0.0
	Overtime	8.3	3.4	4.9	1.7	0.7	0.0
	Incentives	1.0	0.0	2.2	0.0	19.5	0.0
	Other	4.5	1.7	2.2	1.7	11.1	0.0
	Benefits[4]	4.0	0.0	4.6	0.0	6.3	0.0
	Pension/OPEB[5]	10.6	0.0	12.3	0.0	17.1	0.0
Corporate Support	**Total Wages**	**70.7**	**19.7**	**108.7**	**66.0**	**143.5**	**58.1**
	Base Salary[1]	65.6	18.3	101.5	61.2	119.2	57.3
	Overtime	2.1	0.7	2.3	2.0	0.0	0.0
	Incentives	1.1	0.0	2.5	0.0	18.4	0.0
	Other	1.9	0.6	2.5	2.8	5.9	0.8
	Benefits[4]	4.0	0.0	6.1	0.0	7.3	0.0
	Pension/OPEB[5]	10.7	0.0	16.5	0.0	19.7	0.0

1 Based on 2009 year end payroll data for employees in their home-base positions

2 Non-regular includes external service contractors assigned to appropriate representations.

3 Includes an allocation of 29.5 per cent of Hydroelectric Central Support staff to the regulated hydroelectic facilities.

4 Benefits includes group life Insurance, dental, health, maternity and the Employee Family Assistance Program.

5 Represents the current service cost component of total pension/OPEB costs. Current service cost is the only component of the pension/OPEB costs (Discussed in section 6.3.1 Ex. F4-T3-S1) that relates solely to current employees. Current service cost represented the costs of the Pension/OPEB benefit deemed to be accrued by current employees in the year.

2011 created from 2010 using escalation of 4,4,3

2011		PWU		Society		Management Group	
		Regular	Non-Regular[2]	Regular	Non-Regular[2]	Regular	Non-Regular[2]
Nuclear	**Total Wages**	**113.5**	**65.6**	**127.5**	**83.7**	**166.5**	**94.7**
	Base Salary[1]	84.8	44.6	104.6	58.5	135.1	81.8
	Overtime	18.7	12.3	16.4	10.9	1.0	0.0
	Incentives	2.6	0.1	3.6	2.1	19.2	7.9
	Other	7.4	8.7	3.0	12.2	11.2	5.1
	Benefits[4]	4.9	0.0	5.9	0.0	7.5	0.0
	Pension/OPEB[5]	13.1	0.0	15.9	0.0	20.3	0.0
Regulated Hydro	**Total Wages[3]**	**102.4**	**42.5**	**109.1**	**74.7**	**161.6**	**0.0**
	Base Salary[1]	88.0	37.2	99.5	71.2	129.3	0.0
	Overtime	8.6	3.5	5.1	1.8	0.7	0.0
	Incentives	1.1	0.0	2.3	0.0	20.1	0.0
	Other	4.7	1.7	2.3	1.7	11.5	0.0
	Benefits[4]	4.1	0.0	4.8	0.0	6.5	0.0
	Pension/OPEB[5]	11.0	0.0	12.8	0.0	17.6	0.0
Corporate Support	**Total Wages**	**73.5**	**20.4**	**113.1**	**68.6**	**147.8**	**59.8**
	Base Salary[1]	68.2	19.1	105.5	63.6	122.7	59.0
	Overtime	2.2	0.7	2.4	2.1	0.0	0.0
	Incentives	1.2	0.0	2.6	0.0	19.0	0.0
	Other	1.9	0.6	2.6	2.9	6.0	0.8
	Benefits[4]	4.1	0.0	6.4	0.0	7.5	0.0
	Pension/OPEB[5]	11.1	0.0	17.2	0.0	20.3	0.0

1 Based on 2009 year end payroll data for employees in their home-base positions

2 Non-regular includes external service contractors assigned to appropriate representations.

3 Includes an allocation of 29.5 per cent of Hydroelectric Central Support staff to the regulated hydroelectic facilities.

4 Benefits includes group life Insurance, dental, health, maternity and the Employee Family Assistance Program.

5 Represents the current service cost component of total pension/OPEB costs. Current service cost is the only component of the pension/OPEB costs (Discussed in section 6.3.1 Ex. F4-T3-S1) that relates solely to current employees. Current service cost represented the costs of the Pension/OPEB benefit deemed to be accrued by current employees in the year.

2012 created from 2011 using escalation of 4,4,3

2012		PWU		Society		Management Group	
		Regular	Non-Regular[2]	Regular	Non-Regular[2]	Regular	Non-Regular[2]
Nuclear	**Total Wages**	**118.0**	**68.3**	**132.6**	**87.1**	**171.4**	**97.6**
	Base Salary[1]	88.2	46.4	108.8	60.9	139.1	84.2
	Overtime	19.5	12.8	17.0	11.4	1.0	0.0
	Incentives	2.7	0.1	3.7	2.1	19.8	8.1
	Other	7.6	9.0	3.1	12.7	11.6	5.2
	Benefits[4]	5.1	0.0	6.2	0.0	7.8	0.0
	Pension/OPEB[5]	13.6	0.0	16.5	0.0	20.9	0.0
Regulated Hydro	**Total Wages[3]**	**106.5**	**44.2**	**113.5**	**77.7**	**166.4**	**0.0**
	Base Salary[1]	91.5	38.7	103.4	74.1	133.2	0.0
	Overtime	9.0	3.7	5.3	1.8	0.8	0.0
	Incentives	1.1	0.0	2.4	0.0	20.7	0.0
	Other	4.8	1.8	2.4	1.8	11.8	0.0
	Benefits[4]	4.3	0.0	4.9	0.0	6.7	0.0
	Pension/OPEB[5]	11.5	0.0	13.3	0.0	18.1	0.0
Corporate Support	**Total Wages**	**76.5**	**21.3**	**117.6**	**71.4**	**152.2**	**61.6**
	Base Salary[1]	70.9	19.8	109.7	66.2	126.4	60.8
	Overtime	2.3	0.8	2.5	2.2	0.0	0.0
	Incentives	1.2	0.0	2.7	0.0	19.6	0.0
	Other	2.0	0.7	2.7	3.0	6.2	0.9
	Benefits[4]	4.3	0.0	6.6	0.0	7.8	0.0
	Pension/OPEB[5]	11.6	0.0	17.9	0.0	20.9	0.0

1 Based on 2009 year end payroll data for employees in their home-base positions
2 Non-regular includes external service contractors assigned to appropriate representations.
3 Includes an allocation of 29.5 per cent of Hydroelectric Central Support staff to the regulated hydroelectic facilities.
4 Benefits includes group life Insurance, dental, health, maternity and the Employee Family Assistance Program.
5 Represents the current service cost component of total pension/OPEB costs. Current service cost is the only component of the pension/OPEB costs (Discussed in section 6.3.1 Ex. F4-T3-S1) that relates solely to current employees. Current service cost represented the costs of the Pension/OPEB benefit deemed to be accrued by current employees in the year.

VECC Interrogatory #022

Ref: Ex. F4-T3-S1, page 8, Chart 4

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

a) Please provide a similar chart for the year 2009.

b) Please confirm that the results in Chart 4 include all the consulting companies from which OPG gathers information on salary increases.

c) Please explain why no information from Towers Perrin appears on this chart.

d) Please indicate whether the actual salary increases in this chart refer to base pay, benefits, incentive pay, value of non-cash compensation, or total compensation.

e) Please indicate whether the category “All” includes management and non-management employees. If so, then please confirm that to the extent that management and executive increases exceed those for non-management and non-executive personnel, the increase reported for “All” will overstate the actual increases for non-management and non-executive personnel.

f) Please explain how Chart 4 shows that the increases for OPG management/executives were “in line with or below the external market” in 2008.

g) Please confirm that Chart 4 does not indicate that increases in 2009 and 2010 for the PWU, the Society, and the Management Group at OPG were at or below market.

h) Given that OPG has stated that its employees are highly skilled and require appropriate compensation in order to attract and retain them, please explain how OPG manages to attract and retain employees when the increase in compensation is “below market.”

Response

a) The actual 2009 increases will not be available from our consultants until later this year.

b) Yes, these are all the reports that OPG received.

c) We did not receive information from Towers Perrin.

d) The chart refers to increases in actual base pay.

e) The “All” category refers to management and executive salaries only. It does not contain data on unionized employees.

f) In 2008 the salary budget for base pay increases for Management Group employees at OPG was 3.5 per cent. The market data ranged from 3.4 per cent to 3.9 per cent.

g) Chart 4 only refers to salary increases for non-unionized employees in 2008.

h) OPG has engaged, dedicated and skilled employees that are committed to the electricity generation industry. In addition to base pay, OPG offers incentive programs, and health and pension benefits which help to attract and retain employees. On a total compensation basis, most OPG Management Group employees are currently paid at the 50th percentile market level.

VECC Interrogatory #023

Ref: Ex. F4-T3-S1, page 10

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

The evidence states that "The results of the 2007 market review indicated that OPG's Management Group base pay program had fallen significantly below market. The base pay program had not been adjusted since 2002."

a) Did OPG experience any significant difficulties in attracting or retaining management personnel during the period 2002-2007? Please provide details.

b) The evidence goes on to state that "As a result, the salary ranges were adjusted to align with the external market. There were few changes to the individual salaries and the associated cost was approximately $50,000."

   Please explain how this statement is consistent with the claim that "OPG's Management Group base pay program had fallen significantly below market."

Response

a) OPG was experiencing difficulty in certain Management Group occupations and was using a case-by-case approach to deal with attraction and retention issues.

b) OPG benchmarked and reviewed the Management Group salary structure in 2007 and found it lacking against the comparators. As a result, some changes were made to the structure. Structural changes do not translate into individual pay increases. Salary structure changes were designed to reduce the number of individual solutions required. Employee pay was adjusted only when necessary to ensure that all individual base rates were at least at the minimum range of the salary band.

VECC Interrogatory #024

Ref: Ex. F4-T3-S1, page 11, and Figure 1, Attachment 1

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

The evidence at page 11 states:

> "When reviewing management and executive compensation, OPG gathers information from a listing of 24 companies that represent Canadian industries in both the public and private sector. In 2008 and 2009, OPG compared its compensation and benefits program to the 50th percentile of this market. Overall, the compensation and benefits program and employees actual pay are competitive with the external market. Figure 1 in Attachment 1 presents OPG's current market position."

a) Please provide a chart similar to Figure 1 for the year 2008.

b) Please provide the information gathered by OPG for 2008 and 2009 that shows OPG's comparisons for 2008 and 2009 to the 50th percentile of the market re compensation and benefits program.

c) Please provide a list of the companies surveyed by OPG or Mercer for 2008 if it differs from the 2009 sample.

Response

a) See Attachment 1.

b) The charts provided for 2008 and 2009 compare OPG wages and benefits against the 50th percentile of the comparator market.

c)

2008 Comparator Group	
Private Sector	**Public Sector**
Air Canada	Atomic Energy of Canada Ltd
Atco Ltd	BC Hydro
Canadian Natural Resources	Canada Post
Canadian Pacific Railway Ltd	Canadian Broadcasting Corporation
Enbridge Inc	University Health Network
Husky Energy	
Nexen Inc.	
Talisman Energy	
TransAlta Corp	
TransCanada Corp.	

In addition this group of organizations, the following were included for band A-C analysis [(1)]:

Private Sector	Public Sector [(2)]
Canadian National Rail	Hydro One
Nova Chemicals Corp	Sunnybrook Hospital
	The Hospital for Sick Children
	Trillium Health Network
	Mount Sinai

(1) Excluding SVP, Human Resources & Chief Ethics Officer
(2) Data is available from provincial public salary disclosure for the CEO and CFO positions only.

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Attachment 1

Market Compensation Analysis (cont'd)

Agency Review Panel Comparator Group Analysis

2008 Direct Compensation

Band	Data Source	Market Data Points (1) #Orgs	#Jobs	#Incs	Base Salary (2) Midpoint	Actual Average	Annual Incentive (3) (% of Base)	($ Value)	Total Cash Compensation (4)	Total Cash Compensation Position to Market	Long-Term Incentive (5) (% of Base)	($ Value)	Total Direct Compensation (6)	Total Direct Compensation Position to Market
A	OPG	---	1	1	$720,000	$860,000	100%	$860,000	$1,720,000	83%	---	---	$1,720,000	37%
	Market	20	1	20	$921,500		126%	$1,161,090	$2,082,590		281%	$2,589,415	$4,672,005	
B	OPG	---	2	2	$390,000	$525,000	45%	$236,250	$761,250	73%	---	---	$761,250	37%
	Market	12	1	12	$561,000		85%	$476,850	$1,037,850		184%	$1,032,240	$2,070,090	
C	OPG	---	4	4	$330,000	$425,000	45%	$191,250	$616,250	90%	---	---	$616,250	48%
	Market	12	3	41	$395,488		74%	$290,683	$686,171		153%	$606,579	$1,292,750	
D	OPG	---	4	4	$260,000	$313,350	25%	$78,338	$391,688	94%	---	---	$391,688	48%
	Market	8	2	20	$309,830		35%	$108,440	$418,270		130%	$403,592	$821,862	
E	OPG	---	7	9	$200,000	$206,556	25%	$51,639	$258,194	98%	---	---	$258,194	68%
	Market	6	5	156	$204,151		29%	$60,111	$264,262		56%	$113,644	$377,906	
F	OPG	---	15	26	$150,000	$166,304	20%	$33,261	$199,565	100%	---	---	$199,565	80%
	Market	7	7	463	$163,852		22%	$35,701	$199,553		30%	$49,206	$248,759	
G	OPG	---	56	133	$130,000	$133,853	15%	$20,078	$153,931	90%	---	---	$153,931	76%
	Market	9	8	717	$144,647		18%	$26,147	$170,794		21%	$30,435	$201,229	
H	OPG	---	59	273	$110,000	$116,883	15%	$17,532	$134,415	94%	---	---	$134,415	83%
	Market	9	11	932	$125,890		13%	$16,974	$142,863		15%	$18,519	$161,382	
I	OPG	---	6	31	$85,000	$83,351	10%	$8,335	$91,686	83%	---	---	$91,686	74%
	Market	8	4	382	$99,609		11%	$10,716	$110,325		13%	$13,128	$123,453	
J	OPG	---	4	16	$70,000	$66,022	8%	$5,282	$71,304	89%	---	---	$71,304	80%
	Market	14	1	62	$73,109		10%	$7,311	$80,419		12%	$9,065	$89,485	
K	OPG	---	6	94	$55,000	$60,592	8%	$4,847	$65,440	92%	---	---	$65,440	86%
	Market	16	2	356	$65,077		9%	$6,023	$71,100		8%	$5,089	$76,190	
L	OPG	---	7	75	$50,000	$49,654	8%	$3,972	$53,627	92%	---	---	$53,627	92%
	Market	7	2	317	$54,459		7%	$3,809	$58,268		0%	$0	$58,268	

2008 Non-Cash Compensation / **2008 Total**

Band	Data Source	Perquisites (7) Car Allowance	Club Membership	Financial Counseling	Annual Medical	Benefits Pre '01 (8)	PowerFlex Credits (9)	Pension (10)	Total Non-Cash Compensation (11)	Total Non-Cash Compensation Position to Market	Total Remuneration (11)	Total Remuneration Position to Market
A	OPG	$24,000	---	---	---	$33,213	$53,600	$349,823	$460,636	124%	$2,180,636	43%
	Market	$24,000	$7,000	$4,000	$1,200	$27,726	---	$308,923	$372,850		$5,044,855	
B	OPG	$30,000	---	---	---	$19,690	$44,204	$127,441	$221,335	110%	$982,585	43%
	Market	$18,000	$3,500	$3,500	$1,200	$19,166	---	$156,736	$202,102		$2,272,192	
C	OPG	$30,000	---	---	---	$17,232	$28,783	$105,240	$181,255	136%	$797,505	56%
	Market	$12,000	$3,500	$3,500	$1,200	$14,705	---	$98,744	$133,648		$1,426,398	
D	OPG	$20,000	---	---	---	$14,363	$33,511	$68,015	$135,889	142%	$527,577	57%
	Market	$12,000	$3,500	$3,500	$1,200	$12,576	---	$63,026	$95,803		$917,664	
E	OPG	$12,000	---	---	---	$11,905	$15,735	$48,385	$88,025	137%	$346,219	78%
	Market	$9,000	$3,500	$2,000	$1,200	$9,566	---	$38,897	$64,163		$442,069	
F	OPG	-	---	---	---	$9,856	$12,519	$33,456	$55,831	104%	$255,396	84%
	Market	$9,000	$3,500	$2,000	$1,200	$8,340	---	$29,888	$53,928		$302,686	
G	OPG	-	---	---	---	$9,036	$9,336	$28,348	$46,721	95%	$200,651	80%
	Market	$9,000	$3,500	$2,000	$1,200	$7,756	---	$25,772	$49,229		$250,457	
H	OPG	---	---	---	---	$8,217	$7,608	$23,697	$39,522	137%	$173,937	91%
	Market	---	---	---	---	$7,144	---	$21,767	$28,911		$190,293	
I	OPG	---	---	---	---	$7,192	$3,211	$17,564	$27,967	124%	$119,653	82%
	Market	---	---	---	---	$6,277	---	$16,363	$22,639		$146,093	
J	OPG	---	---	---	---	$6,578	$2,403	$13,802	$22,782	136%	$94,086	89%
	Market	---	---	---	---	$5,415	---	$11,384	$16,799		$106,284	
K	OPG	---	---	---	---	$5,963	$2,790	$10,203	$18,956	127%	$84,395	93%
	Market	---	---	---	---	$5,130	---	$9,750	$14,880		$91,069	
L	OPG	---	---	---	---	$5,758	$1,426	$8,895	$16,079	129%	$69,706	99%
	Market	---	---	---	---	$4,777	---	$7,705	$12,482		$70,750	

Notes:

(1) Represents the average number of organizations ("orgs") submitting survey data for benchmark jobs, the total number of benchmark jobs ("jobs") matched to and the total number of incumbents ("incs") for which data was submitted.
For OPG, this represents the actual number of jobs matched to market and the actual number of incumbents in the matched jobs

(2) For OPG, Base Salary Midpoint is the salary midpoint for each band. Actual Average Salary represents the average salary of positions matched for each band.
All other OPG compensation components are derived from the Actual Average value, where applicable. For market data, Base Salary represents the average salary of position matches at the 50th percentile unless otherwise specified in Appendix A.

(3) Represents target annual incentive for OPG and for Bands A-C market data. Value calculated as a % of Base Salary.

(4) Total Cash Compensation equals Base Salary plus Annual Incentive.

(5) OPG does not currently have a Long-Term Incentive Plan. For market data, value is calculated as a % of Base Salary.

(6) Total Direct Compensation equals Total Cash Compensation plus Long-Term Incentive.

(7) Perquisite market data figures are based on previous analysis, as summarized in Mercer letter to Tony Marr, "Industry Perquisite Information - Additional Details", dated December 21, 1999. This data was adjusted to reflect current markets levels.

(8) Benefits include value of Life, Accident, Disability, Health and Dental Benefits paid by the company. Values for LTD, Health and Dental include inflationary/utilization adjustments over the prior year's values for costing changes seen in today's market.
Benefit value is based on the Heritage program. Figures reflect relative values of the benefit programs and not true costs.

(9) For OPG, PowerFlex Credits are as provided by OPG. This benefit was discontinued in 2001. Not all employees are eligible.

(10) For Pension, values for Bands A-C are based on ESPS plan. For market data, pension amounts are based on base salary plus annual incentive targets for bands A-C.

(11) Total Non-Cash Compensation is the sum of Perquisites, Benefits, PowerFlex Credits and Pension.

(12) Total Remuneration is the sum of Total Direct Compensation and Total Non-Cash Compensation. Total Remuneration does not include any amount in respect of non-pension post-retirement benefits.

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Attachment 1

Agency Review Panel Comparator Group Market Compensation Analysis

2009 Direct Compensation

Band	Data Source	Base Salary (1) Midpoint	Base Salary (1) Actual Average	Annual Incentive (2) (% of Base)	Annual Incentive (2) ($ Value)	Total Cash Compensation (3)	Total Cash Compensation Position to Market	Long-Term Incentive (4) (% of Base)	Long-Term Incentive (4) ($ Value)	Total Direct Compensation (5)	Total Direct Compensation Position to Market
A	OPG	$720,000	$800,000	100%	$800,000	$1,600,000	114%	---	---	$1,600,000	63%
	Market	**$805,350**		**75%**	**$604,013**	**$1,409,363**		**142%**	**$1,143,597**	**$2,552,960**	
B	OPG	$390,000	$475,000	45%	$213,750	$688,750	123%	---	---	$688,750	69%
	Market	**$425,390**		**32%**	**$136,125**	**$561,515**		**103%**	**$438,152**	**$999,667**	
C	OPG	$330,000	$421,667	45%	$189,750	$611,417	111%	---	---	$611,417	73%
	Market	**$378,928**		**46%**	**$174,307**	**$553,235**		**75%**	**$284,196**	**$837,431**	
D	OPG	$260,000	$330,890	25%	$82,723	$413,613	127%	---	---	$413,613	89%
	Market	**$251,930**		**29%**	**$73,060**	**$324,990**		**56%**	**$141,081**	**$466,071**	
E	OPG	$200,000	$215,789	25%	$53,947	$269,736	98%	---	---	$269,736	72%
	Market	**$212,695**		**30%**	**$63,809**	**$276,504**		**45%**	**$95,713**	**$372,217**	
F	OPG	$150,000	$172,745	20%	$34,549	$207,294	108%	---	---	$207,294	93%
	Market	**$157,973**		**21%**	**$33,174**	**$191,147**		**20%**	**$31,595**	**$222,742**	
G	OPG	$130,000	$135,577	15%	$20,337	$155,914	95%	---	---	$155,914	82%
	Market	**$140,420**		**17%**	**$23,871**	**$164,291**		**19%**	**$26,680**	**$190,971**	
H	OPG	$110,000	$119,061	15%	$17,859	$136,920	118%	---	---	$136,920	111%
	Market	**$103,250**		**12%**	**$12,390**	**$115,640**		**7%**	**$7,228**	**$122,868**	
I	OPG	$85,000	$81,774	10%	$8,177	$89,951	93%	---	---	$89,951	88%
	Market	**$90,860**		**6%**	**$5,452**	**$96,312**		**7%**	**$6,360**	**$102,672**	
J	OPG	$70,000	$64,784	8%	$5,183	$69,967	91%	---	---	$69,967	87%
	Market	**$73,308**		**5%**	**$3,665**	**$76,973**		**5%**	**$3,665**	**$80,638**	
K	OPG	$55,000	$61,923	8%	$4,954	$66,877	93%	---	---	$66,877	89%
	Market	**$65,048**		**10%**	**$6,505**	**$71,553**		**6%**	**$3,903**	**$75,456**	
L	OPG	$50,000	$51,586	8%	$4,127	$55,713	100%	---	---	$55,713	96%
	Market	**$53,690**		**4%**	**$2,148**	**$55,838**		**4%**	**$2,148**	**$57,986**	

2009 Non-Cash Compensation / 2009 Total

Band	Data Source	Perquisites (6) Car Allowance	Perquisites (6) Club Membership	Perquisites (6) Financial Counseling	Perquisites (6) Annual Medical	Benefits Pre '01 (7)	PowerFlex Credits (8)	Pension (9)	Total Non-Cash Compensation (10)	Total Non-Cash Compensation Position to Market	Total Remuneration (11)	Total Remuneration Position to Market
A	OPG	$24,000	---	---	---	$33,662	$53,600	$158,197	$269,459	179%	$1,869,459	69%
	Market	**$24,000**	**$7,000**	**$4,000**	**$1,200**	**$30,431**	**---**	**$84,249**	**$150,880**		**$2,703,840**	
B	OPG	$30,000	---	---	---	$20,042	$53,268	$52,390	$155,700	176%	$844,450	78%
	Market	**$18,000**	**$3,500**	**$3,500**	**$1,200**	**$18,813**	**---**	**$43,348**	**$88,361**		**$1,088,028**	
C	OPG	$30,000	---	---	---	$17,565	$36,108	$41,864	$125,537	190%	$736,954	82%
	Market	**$12,000**	**$3,500**	**$3,500**	**$1,200**	**$15,136**	**---**	**$30,764**	**$66,100**		**$903,531**	
D	OPG	$20,000	---	---	---	$14,676	$33,338	$23,292	$91,306	162%	$504,919	97%
	Market	**$12,000**	**$3,500**	**$3,500**	**$1,200**	**$12,468**	**---**	**$23,787**	**$56,455**		**$522,526**	
E	OPG	$12,000	---	---	---	$12,200	$16,242	$15,800	$56,242	123%	$325,978	78%
	Market	**$9,000**	**$3,500**	**$2,000**	**$1,200**	**$10,856**	**---**	**$19,093**	**$45,649**		**$417,866**	
F	OPG	---	---	---	---	$10,136	$13,321	$10,804	$34,261	89%	$241,555	93%
	Market	**$9,000**	**$3,500**	**$2,000**	**$1,200**	**$8,832**	**---**	**$13,824**	**$38,356**		**$261,098**	
G	OPG	---	---	---	---	$9,311	$10,757	$8,963	$29,031	79%	$184,945	81%
	Market	**$9,000**	**$3,500**	**$2,000**	**$1,200**	**$8,250**	**---**	**$12,634**	**$36,584**		**$227,555**	
H	OPG	---	---	---	---	$8,485	$8,889	$7,574	$24,948	161%	$161,868	117%
	Market	**---**	**---**	**---**	**---**	**$6,839**	**---**	**$8,670**	**$15,509**		**$138,377**	
I	OPG	---	---	---	---	$7,453	$4,375	$5,877	$17,705	130%	$107,656	93%
	Market	**---**	**---**	**---**	**---**	**$6,383**	**---**	**$7,285**	**$13,668**		**$116,340**	
J	OPG	---	---	---	---	$6,834	$3,728	$4,655	$15,217	136%	$85,184	93%
	Market	**---**	**---**	**---**	**---**	**$5,666**	**---**	**$5,490**	**$11,156**		**$91,794**	
K	OPG	---	---	---	---	$6,215	$3,544	$3,394	$13,153	129%	$80,030	93%
	Market	**---**	**---**	**---**	**---**	**$5,378**	**---**	**$4,849**	**$10,227**		**$85,683**	
L	OPG	---	---	---	---	$6,009	$2,823	$2,988	$11,820	135%	$67,533	101%
	Market	**---**	**---**	**---**	**---**	**$5,002**	**---**	**$3,784**	**$8,786**		**$66,772**	

Notes:

(1) For OPG, Base Salary Midpoint is the salary midpoint for each band. Actual Average Salary represents the average salary of positions matched for each band. All other OPG compensation components are derived from the Actual Average value, where applicable. For market data, Base Salary represents the average salary of position matches at the 50th percentile unless otherwise specified in the Benchmark Jobs table.
(2) Represents target annual incentive for OPG and for Bands A-L market data. Value calculated as a % of Base Salary.
(3) Total Cash Compensation equals Base Salary plus Annual Incentive.
(4) OPG does not currently have a Long-Term Incentive Plan. For market data, value is calculated as a % of Base Salary.
(5) Total Direct Compensation equals Total Cash Compensation plus Long-Term Incentive.
(6) Perquisite market data figures are based on previous analysis, as summarized in Mercer letter to Tony Marr, "Industry Perquisite Information - Additional Details", dated December 21, 1999. This data was adjusted to reflect current markets levels.
(7) Benefits include value of Life, Accident, Disability, Health and Dental Benefits paid by the company. Values for LTD, Health and Dental include inflationary/utilization adjustments over the prior year's values for costing changes seen in today's market. Benefit value is based on the Heritage program. Figures reflect relative values of the benefit programs and not true costs.
(8) For OPG, PowerFlex Credits are as provided by OPG. This benefit was discontinued in 2001. Not all employees are eligible.
(9) For Pension, values for Bands A-H are based on ESPS plan and values for Bands I-L are based on SPS plan. For market data, pension amounts are based on base salary plus annual incentive targets for bands A-L.

VECC Interrogatory #025

Ref: Ex. F3-T1-S2

Issue Number: 6.9
Issue: Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

Interrogatory

With respect to total Corporate Support and Administrative Costs allocated between regulated and unregulated operations, please provide a table showing total costs budgeted/actual broken down by corporate group (as per tables 1 and 2) for each year 2007-2012 inclusive.

Response

Please see the requested table below.

Comparison of Corporate Support & Administrative Costs ($M)

OPG

Line No.	Corporate Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Finance**	58.6	(0.2)	58.4	(0.3)	58.1	(4.8)	62.9
2	**Corporate Affairs**	24.6	(1.3)	23.3	5.9	29.2	(8.4)	37.6
3	**Business Services & IT**[1]	221.0	(7.0)	214.0	(6.6)	207.4	(31.6)	239.0
4	**Corporate Centre**[2]	21.5	(2.3)	19.2	2.3	21.5	(1.3)	22.8
5	**Energy Markets**	23.2	(3.2)	20.0	0.2	20.2	(1.3)	21.5
6	**Human Resources**	54.6	(3.4)	51.2	2.0	53.2	0.8	52.4
7	**Total**	403.5	(17.4)	386.1	3.5	389.6	(46.6)	436.2

Line No.	Corporate Group	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
8	**Finance**	58.1	2.4	60.5	(3.7)	64.2
9	**Corporate Affairs**	29.2	(2.5)	26.7	(11.0)	37.7
10	**Business Services & IT**[1]	207.4	(0.2)	207.2	(29.5)	236.7
11	**Corporate Centre**[2]	21.5	(2.2)	19.3	(3.6)	22.9
12	**Energy Markets**	20.2	0.2	20.4	(1.5)	21.9
13	**Human Resources**	53.2	0.6	53.8	0.0	53.8
14	**Total**	389.6	(1.7)	387.9	(49.3)	437.2

Line No.	Corporate Group	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
15	**Finance**	60.5	(0.1)	60.4	(0.1)	60.3	0.2	60.5
16	**Corporate Affairs**	26.7	7.1	33.8	(3.3)	30.5	2.8	33.3
17	**Business Services & IT**[1]	207.2	(1.9)	205.3	2.8	208.1	(0.4)	207.7
18	**Corporate Centre**[2]	19.3	6.9	26.2	0.3	26.5	1.6	28.1
19	**Energy Markets**	20.4	1.6	22.0	(0.8)	21.2	0.3	21.5
20	**Human Resources**	53.8	0.2	54.0	0.8	54.8	0.4	55.2
21	**Total**	387.9	13.8	401.7	(0.3)	401.4	4.9	406.3

1 Formerly Chief Information Office (CIO)

2 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

VECC Interrogatory #026

Ref: Ex. G1-T1-S1, Table 1

Issue Number: 7.1
Issue: Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Interrogatory

Please re-issue Table 1, adding columns for 2011 and 2012 that provide forecasts for Segregated Mode of Operation and Water Transactions rows on the basis of the Board approved Methodology from EB-2007-0905. Please also provide a description of the calculation in each case.

Response

The requested revisions to the Segregated Mode of Operation ("SMO") and Water Transactions ("WT") rows of Table 1[1] are shown below.

The forecast for 2011 and 2012 is the average of the net revenues from SMO and WT for the last three years available (2007, 2008 and 2009).

IR L-14-026
Exhibit G1
Tab 1
Schedule 1
Table 1

										IR L-14-026	IR L-14-026
Revenue Source	2007 Budget	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget	2011 Plan	2012 Plan	2011 Forecast	2012 Forecast
Ancillary Services	31.6	35.6	32.4	41.2	35.7	42.5	39.1	38.3	39.5	38.3	38.3
Segregated Mode of Operation	0.0	4.4	5.0	13.7	6.6	3.6	6.6	1.5	1.6	7.2	7.2
Water Transactions	0.0	4.3	5.2	8.8	6.9	4.9	6.9	5.1	5.2	6.0	6.0
Total	31.6	44.3	42.6	63.7	49.2	51.0	52.6	44.9	46.2	51.5	51.5

[1] Ex. G1-T1-S1, Table 1

VECC Interrogatory #030

Ref: General

Issue Number: 8.1
Issue: Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

Interrogatory

Board staff IR 128 requests as follows: "Please file policy positions or papers, or decisions from any energy regulatory or other bodies that were issued since the EB-2009-0905 decision with respect to the revenue requirement methodology for recovering nuclear liabilities?" (emphasis added) Please enlarge the scope of that request to include such positions, papers or decisions that precede the decision in EB-2009-0905 that were not brought to the attention of the Board in EB-2009-0905.

Response

The reference number in the question is to OPG's payment amount application, EB-2007-0905, not EB-2009-0905.

In June, 2008, OPG provided undertaking Ex. J1.3 Addendum in EB-2007-0905 (see Attachment 1) which contains the precedents reviewed by Fosters Associates, Inc. that related to the recovery of nuclear liability costs.

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OPG is not aware of any policy positions or papers or decisions from any energy regulatory or other bodies that were issued between the oral hearing in June 2008 and the OEB's EB-2007-0905 Decision With Reasons issued November 3, 2008. Ex. L-01-128 addresses the time period after November 3, 2008.

ATTACHMENT 1
UNFUNDED NUCLEAR LIABILITIES PRECEDENTS

There are only two utilities in Canada that have nuclear generation assets and related nuclear liabilities. Given the lack of precedents in Canada,[1] the focus is on regulatory practice in the U.S.

Prior to the adoption of FASB 143, Accounting for Asset Retirement Obligations, in the U.S. (which corresponds to CICA 3110 in Canada), the original cost of utilities' nuclear assets was simply the acquisition cost, with no adjustment or recognition in the undepreciated original cost for any decommissioning liability. The vast majority of U.S. utilities[2] with nuclear generation (33 of 38) recovered decommissioning costs[3] as part of their depreciation expense. The basis for determining the total cost to be depreciated was the original cost of the asset plus the estimated decommissioning costs. Decommissioning costs were treated as negative salvage, and the depreciation rate was set to permit recovery of the decommissioning costs.

As a result of this practice, at the end of the life of the asset, the asset balance would be negative, with the reserve for depreciation exceeding the original cost of the asset by the amount of the decommissioning obligation. In effect, the liability for decommissioning was included (but not explicitly identified) in the reserve for accumulated depreciation; the liability was not explicitly disclosed on the utilities' balance sheets. Amounts collected in depreciation expense for decommissioning costs were a source of funding for the segregated trusts required to be able to discharge the decommissioning obligation. The earnings on the segregated funds were typically credited to accumulated depreciation, which increased the amount of accumulated depreciation and decreased the decommissioning costs to be recovered from ratepayers. When an estimate of the

[1] Neither of the other two Canadian utilities with nuclear assets, Hydro Québec and New Brunswick Power, have had those assets subject to rate base rate of return regulation. Therefore, neither case provides a precedent for OPG's circumstances

[2] James R. Boatsman, Inder K. Khurana, and Martha L. Loudder, *The Economic Implications of Proposed Changes in the Accounting for Nuclear Decommissioning Costs*, American Accounting Association, *Accounting Horizons*, Vol. 14, No. 2, June 2000, pp. 211-233.

[3] The liability for spent (or used) fuel lies with the government, to whom the utilities pay a per kWh charge for assuming the disposal obligation.

decommissioning costs was updated, the depreciation rate would be changed to allow for recovery of the revised amount; no retroactive adjustments were made to the depreciation reserve or to equity as a result of the updated cost estimates.

The remaining firms with nuclear assets used what is referred to as the non-current liability method. Under that method, the depreciation expense was based solely on the acquisition cost of the plant, with decommissioning expense recovered as a separate revenue requirement item. The accumulated decommissioning expense was recognized through a straight-line accrual of the liability.

The amount of expense recognized was the same for both the depreciation expense/negative salvage and non-current liability methodologies, but the composition of assets and liabilities was different. Under the first method, the rate base was reduced for accumulated decommissioning expense via the reserve for depreciation; under the second method, the rate base was reduced by netting the non-current liability against rate base. In both cases, the rate base was reduced by the cumulative decommissioning expense that had been recovered from customers, in the first approach through the reserve for depreciation and in the second approach through the reduction of the rate base by the cumulative liability.

The adoption of FASB 143 in 2003 required the utilities to estimate the fair value of their asset retirement obligations, record them as a liability and capitalize the associated ARCs as part of the original cost of the assets. For utilities with nuclear generation assets, the adoption of FASB 143 resulted in the recognition of legal ARO liabilities related to decommissioning. The audited financial statements of the utilities now reflect the full amount of the decommissioning AROs on the liability side, the ARCs and the decommissioning trust funds on the asset side.[4]

To my knowledge, the adoption of FASB 143 has not resulted in material changes in regulatory practice with respect to rate base and capital structure for U.S. utilities with ARCs and AROs. Utilities continued to use long-established regulatory practices for regulatory accounting purposes rather than switch to GAAP accounting. For U.S. utilities

[4] Some of the utilities also have trust funds on the balance sheet for spent fuel. Spent fuel funds are funded through a per kWh of nuclear production charge.

that qualified for rate regulated accounting,[5] adjustments for differences between GAAP and regulatory accounting could be and were made in the GAAP financial statements to account for the differences. For these utilities, regulatory assets and liabilities were recorded to recognize the cumulative effects of differences in amounts recovered and recoverable under the old and new standards. If the cumulative expense that has been recovered in rates as dictated by regulatory practice is less than the cumulative expense recorded in the financial statements (including the interest component) under ARO accounting, a regulatory asset, which recognizes the assurance that the utility will be able to collect the difference in future rates, appears on the GAAP financial statements

APPLICABILITY OF US PRACTICE TO OPG

INTRODUCTION

It is necessary to set forth the regulatory objective in order to determine the appropriate treatment of nuclear liabilities in the context of the regulated rate base and/or capital structure. The objective in the decisions as to how nuclear liabilities should be treated for regulatory purposes is to ensure that OPG is provided an opportunity to recover, in its revenue requirement, the costs of financing the assets that are used and useful in the provision of public service.

The measurement of the amount of investor-supplied capital that is required to finance regulated assets typically starts by focusing on the assets that are devoted to public service, that is, the rate base. The starting point for the rate base is net depreciated property, plant and equipment in service plus an allowance for working capital. The next step is essentially to identify funds that have been made available by ratepayers that are financing utility assets. Examples of these funds include accumulated deferred taxes, contributions in aid of construction, and customer deposits. Ratepayer-supplied funds are in most cases deducted from the rate base.[6] When rate-payer supplied funds are

[5] As in Canada, if certain criteria are met, U.S. utilities are exempt from certain GAAP reporting standards.

[6] In a few instances in Canada, customer-supplied funds in the form of accumulated deferred taxes, e.g., Consumers Gas, now Enbridge Gas (in the mid-1980's), FortisBC and Pacific Northern Gas, have been included in the capital structure. Customer contributions have on

deducted directly from the "gross" rate base, the resulting net rate base is typically viewed as a proxy for investor-supplied capital. Thus, the objectives are to ensure that OPG has a reasonable opportunity to recover the costs of the investor-supplied capital financing regulated assets, while simultaneously ensuring that ratepayers are not charged for funds that they have provided. As part of that task, appropriate rate base/regulated capital structure treatment for unfunded nuclear liabilities needs to be evaluated.

Regulation 53/05 requires the Ontario Energy Board to accept the asset values as per the most recently audited financial statements for purposes of establishing the rate base. The ARCs are included in the original cost of the assets and will continue to be included in rate base. Thus, the point of departure is different from that of the U.S. utilities.

In addition, U.S. utilities are generally regulated on the basis of an actual capital structure, rather than a deemed capital structure. In the case of OPG, the choice of deemed capital structure can (and does) take into account the inclusion of the ARCs in rate base and the risks associated with recovery of the liabilities that have been assumed by OPG. The relative size of the liabilities and the attendant recovery risks (compared to the productive capacity of the plants) assumed by OPG is materially larger than that of U.S. utilities with regulated nuclear plants. [7] The resulting approach to the deemed financing of the total assets needs to recognize the size of the liability that has been assumed. In addition, the contributions to the decommissioning and waste management funds required under ONFA precede the recovery of the related expense in the revenue requirement. Thus, investor funds are effectively required to pre-fund the funds, for which there is an opportunity cost. All of these factors lead to the conclusion that an alternative approach (to that of the U.S. utilities) is warranted for OPG.

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occasion been expressed both ways in the same regulatory decision e.g., Alberta utilities, including ATCO Gas and AltaGas Utilities. When customer-supplied funds are assigned a zero cost, the impact of including them in the capital structure rather than deducting them from rate base should be neutral.

[7] Two examples are: Arizona Public Service has a regulated rate base of over $4 billion and total asset retirement obligations of $270 million. AmerenUE has a regulated rate base in Missouri (where its nuclear plant is located) of approximately $11 billion, of which $3 billion is nuclear, and total asset retirement obligations of under $500 million. At the end of 2007, OPG's asset retirement obligations related to its nuclear plants were $2.5 billion compared to a total nuclear rate base of $3.5 billion. Further, OPG's total nuclear liabilities exceed $10 billion; the cost of decommissioning all nuclear plants in the U.S. (over 100 reactors) is approximately $35 billion. OPG's exposure alone is thus close to one-third of that of U.S. utilities with nuclear plants.

With ARCs included in OPG's rate base, the issue from a capital structure and recovery of an appropriate return perspective becomes one of the treatment of the unfunded liability. Three possible approaches are outlined in the table below.

	Option 2 from CIBC	**Rate Base Method**	**Method #3**
Rate Base and Capital Structure	Deduct unfunded liability from gross rate base	No adjustment to rate base. Use deemed debt in capital structure as plug to equate rate base and capital structure	No adjustment to rate base. Include unfunded liability in capital structure as a source of debt financing
Recovery of ARC Principal	Recover ARC principal in depreciation expense	Recover ARC principal in depreciation expense	Recover ARC principal in depreciation expense
Recovery of Return	Recover accretion in OM&A expense. Credit revenue requirement for segregated fund earnings. Apply weighted average cost of capital to rate base minus unfunded liability	Apply weighted average cost of capital to rate base where rate base is supported by a deemed capital structure of debt plus equity; exclude consideration of accretion and seg fund earnings	Apply weighted average cost of capital to rate base. WACC is based on a deemed capital structure of debt (including unfunded liability as one debt source) plus equity.

From an economic impact perspective, the Rate Base Method and Method #3 will provide the same income stream when a deemed capital structure is used and the discount rate on the unfunded liability is the same as the cost of debt that would be used in the Rate Base Method. Option 2 from the CIBC, which deducts the unfunded liability from rate base, effectively negates the requirement that the OEB accept OPG's asset values as per the most recently audited financial statements for purposes of establishing rate base

The treatment of unfunded nuclear liabilities should be premised on the following:

(1) The proposed deemed capital structure, comprised of debt and equity, should reflect the stand-alone business risks of the regulated operations;

(2) While the actual debt cost of OPG is used to establish the notional debt expense to be included in the revenue requirement, effectively, a deemed capital structure does not explicitly trace dollars of financing to the specific asset being financed.

However, since the unfunded nuclear used fuel management and decommissioning liability can be associated with an identifiable rate base asset of material size, it may be interpreted as one source of rate base financing. Thus, while the choice of methodology should ensure that OPG recovers the costs of financing its rate base assets, it should also ensure that there is no double recovery of financing costs.

In my opinion, the Rate Base Method is the preferred approach. Method #3 represents another valid approach to the treatment of the unfunded nuclear liability for regulatory purposes. Both methods entail deeming a common equity ratio compatible with the stand-alone business risks of the regulated operations. The deemed common equity ratio would be the same under both approaches. Both apply a weighted average cost of capital to the same measurement of rate base. While Method 3 may provide a closer matching of the financing costs recovered in the revenue requirement with those incurred, the Rate Base Method follows the traditional practice in Ontario of not “streaming” or “tracing” of financing costs. In effect, the Rate Base Method treats asset retirement costs as any other rate base asset that is financed by a combination of debt and equity.

Further, I am not aware of any utility that has been required to include an unfunded liability related to asset retirement obligations in capital structure, as would be the case if Method 3 were adopted. Two utilities in Ontario have included ARCs in rate base, but their deemed capital structures are comprised solely of debt and common equity.

Considering the advantages of both approaches, the Rate Base Method, which is the same methodology adopted for purposes of interim rates, is recommended. Under the Rate Base Method, the debt component of the deemed capital structure would reflect the allocation of actual and forecast OPG debt at the embedded cost, with the amount of any difference between capitalization and rate base reflecting OPG’s cost of long-term debt for that period.

VECC Interrogatory #031

Ref: Ex. C2-T1-S1, pages 4-6

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

a) Please discuss whether the intent of the reference plan prepared in accordance with the Ontario Nuclear Funds Agreement ("ONFA") is to capture all of the costs for all of OPG's nuclear waste management and decommissioning obligations, and whether that is the case. To the extent that there are costs for nuclear waste management and decommissioning that are not captured in the reference plan please separately identify and quantify those costs as they appear in the revenue requirement analysis in table 5 at Exhibit C2, Tab 1, Schedule 2.

b) Please discuss whether the intent behind the segregated funds established by the ONFA is to have all of OPG's nuclear waste management and decommissioning obligations directly paid for out of the segregated funds, and whether that is the case. (It appears to VECC at Exhibit C2, Tab 1, Schedule 2, Table 1 note 4 and Table 2 note 6 that not all of OPG's nuclear waste management and decommissioning obligations are paid for directly out of segregated funds.) To the extent that there are costs for nuclear waste management and decommissioning that are not paid for out of the segregated funds, please separately identify and quantify those costs as they appear in the revenue requirement analysis in table 5 at Exhibit C2, Tab 1, Schedule 2.

Response

a) The reference plan prepared in accordance with the Ontario Nuclear Funds Agreement ("ONFA") includes all the costs of managing nuclear waste and decommissioning of all OPG-owned nuclear facilities as required by the Canadian Nuclear Safety Commission ("CNSC").

b) The intent behind the segregated funds established by the ONFA is to ensure that sufficient funds are accumulated or otherwise are available to pay for the costs of the long-term disposal management of all of OPG's nuclear waste and decommissioning obligations. The short-term storage and management of OPG's nuclear waste obligations is paid out of OPG operating funds and not from the segregated funds.

OPG is not able to break out the noted expense lines in Table 5 as requested. With respect to the expenses for nuclear waste management and decommissioning as represented by lines 1, 2, 3 for prescribed facilities and lines 7, 8, 9 for Bruce facilities in

Ex. C2-T1-S2, Table 5, OPG does not record or track these expenses by funding source as it is not required for accounting purposes.

OPG does not track the asset retirement costs based on the funding source (long-term disposal financed by ONFA funds or short-term storage financed from operational cash) for depreciation purposes (lines 1 and 7 in Table 5). OPG does not record used fuel (lines 2 and 8 in Table 5) and low and intermediate level waste (line 3 and 9 in Table 5) variable expenses based on the funding source as it is irrelevant to the booking of the incremental cost incurred as a result of producing the extra quantity of used fuel bundles or waste.

VECC Interrogatory #032

Ref: Ex. C2-T1-S2

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

On page 1, lines 17 to 20 OPG states that "OPG is continuing to investigate the impacts of the OEB approved revenue requirement treatment on its ability to fully recover its nuclear liabilities. Based on the results of this investigation, OPG may propose modifications to the existing treatment or an alternative treatment in a future application." When OPG speaks about "its ability to recover its nuclear liabilities", does OPG include in the definition of nuclear liabilities any return or profit connected to its nuclear waste management and decommissioning obligations, or does OPG conceptually perceive such obligations simply as expenses?

Response

OPG treats its nuclear liabilities as expenses.

VECC Interrogatory #033

Ref: Ex. C2-T1-S2

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

On page 6, lines 14-17 it appears that the evidence is specifically discussing the forecast of the earnings on the segregated funds, but refers at line 14 to a forecast of the value of the unfunded nuclear liabilities; should that reference be to a forecast "of the earnings on the segregated funds"?

Response

The statement referred to in the interrogatory describes the expected earnings on the segregated funds as being 5.15 per cent. The forecast earnings rate of 5.15 per cent is a key assumption in determining the value of the unfunded nuclear liability. In order to calculate the unfunded nuclear liability, OPG needs to forecast both the asset retirement obligation and the value of the segregated funds for the prescribed assets.

VECC Interrogatory #034

Ref: Ex. C2-T1-S2, Tables 1 and 2

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

The following questions all relate to line items in Tables 1 and 2:

a) Tables 1 and 2 represent a division of the segregated funds between prescribed assets and the Bruce facilities. However it appears to VECC, in reading Exhibit C2, Tab 1, Schedule 1, page 7 that the segregated funds are also separable between:

   i. a Used Fuel Fund that attracts the provincial guarantee of a return of 3.25% over the change in the Consumer Price Index,

   ii. a Used Fuel Fund that does not attract a guaranteed rate of return, and

   iii. The Decommissioning Fund, which does not attract a guaranteed rate of return, but which includes the option of transferring funds out of the Fund to the OEFC and the Used Fuel Fund in equal portions under specified conditions.

   Accordingly, please break out the Nuclear Segregated funds Balance sections of Tables 1 and 2 into the three categories of funds described above.

b) Please confirm that in terms of actual expenses (i.e. excluding accounting expenses such as depreciation and accretion, and excluding fund contributions) related to OPG's nuclear waste management and decommissioning costs, the total amounts paid by OPG in any particular year appear at line 8 of Table 1 for the prescribed facilities and at line 7 of Table 2 for the Bruce Facilities. If that is not the case, please explain what other actual expenses in each year OPG either incurred or is forecast to incur in relation to its nuclear waste management and decommissioning costs and where they are accounted for in Tables 1 and 2. Do the expenditures in these two lines represent a combination of disbursements out of segregated funds and other, direct expenditures by OPG, or are these expenditures in addition to disbursements out of the segregated fund?

c) Please confirm that in terms of disbursements out of the segregated funds, the total disbursements in any particular year appear at line 16 of Table 1 and line 17 of Table 2. If that is not the case, please explain what other disbursements out of the segregated funds have been (or will be) made in any particular year and where they are accounted for in Tables 1 and 2.

d) Please explain the relationship between the total disbursements out of the segregated fund in any particular year as confirmed in IR 3 b) and the reference plan. In particular, to what extent do the disbursements in any particular year correspond to the reference plan estimate of costs for that same year? Assuming there is a correlation between the disbursements in a particular year and the reference plans' estimate of costs for that same year, how are any variations between the two amounts reconciled?

e) Please confirm that, in principle, the earnings on the segregated funds forecast at line 14 of Table 1 and line 15 of table 2 are forecasted on the assumption of a 5.15% return in accordance with the statement at Exhibit C2, Tab 1, Schedule 2, page 6, lines 14-17. Please provide an example of how the segregated fund earnings were calculated for 2011 and 2012. For instance, how was the 5.15% return used to arrive at forecast earnings of $280.6M for 2011 at line 14 of Table 1?

f) Please confirm that the contributions to the segregated funds forecast at line 15 of Table 1 and line 16 at table 2 reconcile directly with the funding requirements set out at Exhibit C2, Tab 1, Schedule 1, Attachment 1 Table 2. Please describe the conditions under which the funding requirements in Attachment 1 Table 2 might be changed, both in terms of procedure (i.e. during the course of an update to the reference plan) and in terms of cause. Please identify any known causes of future changes in the funding requirements and when those changes will be reflected in changed contribution requirements.

Response

a) Attachment 1, Table 1 and Table 2 provide the requested breakout of the Nuclear Segregated Funds Balance from Ex. C2-T1-S2, Tables 1 and 2 into the three categories of funds described above for prescribed facilities and Bruce facilities.

b) The question identifies the wrong line numbers in Ex. C2-T1-S2, Tables 1 and 2. The references should be line 7 of Ex. C2-T1-S2, Table 1 (prescribed facilities) and line 8 of Ex. C2-T1-S1, Table 2 (Bruce facilities). The total amount paid by OPG in any particular year is reflected in the line described as "Expenditures for Used Fuel, Waste Management & Decommissioning." The expenditure for prescribed facilities is found at Ex. C2-T1-S2, Table 1, line 7 and the expenditure for the Bruce facilities is found at Ex. C2-T1-S2, Table 2, line 8. These expenditures are funded from the segregated funds and from OPG's operations.

c) The total disbursements out of the segregated funds are presented in line 16 of Table 1 and line 17 in Table 2.

d) OPG assumes that the reference to "IR 3 b)" in the question is incorrect and the correct reference is VECC Interrogatory 34c). The Ontario Nuclear Funds Agreement ("ONFA") reference plan is a long-term plan prepared to ensure sufficient funds are accumulated to pay for the lifecycle costs of managing nuclear waste and decommissioning the nuclear generating stations and support facilities. It is updated and approved by Ontario Financing Authority ("OFA") every five years. Based on the ONFA Reference Plan, OPG develops a business plan each year to govern annual disbursements. The annual business plan incorporates the program funding requirements based on the latest information, some of which may not be captured in the ONFA Reference Plan. The business plan is subject to annual review and approval by the OFA. Once approved, the business plan determines the allowed level of expenditures for each ONFA-funded program in the year. OFA approval is required for any spending above budgeted levels.

Every five years, each waste program is re-estimated in detail and that work forms the basis of the liability calculation for ONFA and is used to update the asset retirement obligation ("ARO") for OPG. The re-estimation takes into account work done to date, under/over expenditures versus budget, plans for future work and future waste volume estimates.

e) The earnings on the segregated funds forecast at line 14 of Table 1 and line 15 of Table 2 are forecast based on the assumption of a 5.15 per cent return and adjusted for disbursements and contributions during the year.

The calculation of the forecast earnings of $280.6M for 2011 at line 14 of Table 1 is as follows:

Earnings on Opening Balance	**($M)**	**Reference**
2011 Segregated Funds Opening Balance (Table 1, Line 11)	5,399.6	
Earnings Based on Assumed Rate of Return 5.15 per cent	278.1	A
Earnings on Net Inflow during 2011		
2011 Forecasted Contributions (Table 1, line 15)	145.0	
2011 Forecasted Disbursements (Table 1, line 16)	(46.6)	
Net Inflow Forecasted for 2011	98.4	
Earnings on Net Inflow Forecasted for 2011 (Note 1)	2.5	B
Total Forecasted Earnings for 2011 (A+B)	**280.6**	Table 1, line 14

[Note 1: It is assumed that the contributions and disbursements occur at the middle of the year. Thus, the earnings on the net inflow is $98.4M x 50% x 5.15% = $2.5M.]

f) The contributions to the segregated funds forecast at line 15 in Table 1 and line 16 in Table 2 reconcile directly with the funding requirements on an aggregated basis set out at Ex. C2-T1-S1, Attachment 1, Table 2.

Two subsections of the ONFA (3.61 and 4.61) govern the updating of contributions. In summary the main conditions/causes that would require the updating of the contributions schedule of the segregated funds are:

- A new or amended Reference Plan becomes an Approved Reference Plan (approved by the Province of Ontario).
- The Province of Ontario makes a payment into the segregated funds.
- A determination by OPG or the Province of Ontario that the segregated funds are subject to tax of any nature or having become subject to such tax, is no longer subject to such tax.
- The Province of Ontario approves or is deemed to have approved a CNSC Reconciliation Statement.

The only known cause of future change is the upcoming reference plan update which is at an early stage of development and is not expected to be approved by the Province of Ontario until the end of 2011.

Numbers may not add due to rounding.

Table 1
Prescribed Facilities - Nuclear Segregated Funds Balance Section Only ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note	2008 Actual[1]	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	NUCLEAR SEGREGATED FUNDS BALANCE						
1	**Opening Balance**	2	4,853.0	4,584.2	5,058.7	5,399.6	5,778.5
2	**Reallocation Adjustment**	3	(23.1)	0.0	0.0	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2 or line 4 + line 5 + line 6)		4,829.9	4,584.2	5,058.7	5,399.6	5,778.5
4	**Used Fuel Fund (Provincial Guarantee Portion)**		2,085.1	2,259.9	2,437.3	2,627.0	2,824.7
5	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	14.2	85.1	154.4
6	**Decommissioning Fund**		2,744.8	2,324.3	2,607.2	2,687.5	2,799.4
7	**Earnings (Losses)** (line 8 + line 9 + line 10)		(242.1)	415.5	262.6	280.6	299.7
8	**Used Fuel Fund (Provincial Guarantee Portion)**		122.3	78.2	127.1	136.9	146.9
9	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	2.5	6.0	9.5
10	**Decommissioning Fund**		(364.3)	337.3	132.9	137.7	143.3
11	**Contributions** (line 12 + line 13 + line 14)		58.9	124.7	150.2	145.0	140.4
12	**Used Fuel Fund (Provincial Guarantee Portion)**		58.9	110.5	81.7	81.7	78.7
13	**Used Fuel Fund (Non Guarantee Portion)**		0.0	14.2	68.4	63.2	61.7
14	**Decommissioning Fund**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements** (line 16 + line 17 + line 18)		(62.5)	(65.7)	(71.9)	(46.6)	(58.0)
16	**Used Fuel Fund (Provincial Guarantee Portion)**		(6.4)	(11.3)	(19.3)	(20.8)	(22.5)
17	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	0.0	0.0	0.0
18	**Decommissioning Fund**		(56.2)	(54.3)	(52.6)	(25.8)	(35.5)
19	**Closing Balance** (line 20 + line 21 + line 22)		4,584.2	5,058.7	5,399.6	5,778.5	6,160.7
20	**Used Fuel Fund (Provincial Guarantee Portion)** (line 4 + line 8 + line 12 + line 16)		2,259.9	2,437.3	2,627.0	2,824.7	3,027.9
21	**Used Fuel Fund (Non Guarantee Portion)** (line 5 + line 9 + line 13 + line 17)		0.0	14.2	85.1	154.4	225.6
22	**Decommissioning Fund** (line 6 + line 10 + line 14 + line 18)		2,324.3	2,607.2	2,687.5	2,799.4	2,907.2

Notes:
1 2008 values are annual amounts.
2 2008 amount per EB-2007-0905 Payment Amounts Order, Appendix A Table 8.
3 See Ex. C2-T1-S2 Table 1, Note 5.

Numbers may not add due to rounding.

Table 2
Bruce Facilities - Nuclear Segregated Funds Balance Section Only ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note	2008 Actual[1]	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	NUCLEAR SEGREGATED FUNDS BALANCE						
1	**Opening Balance**	2	4,410.0	4,625.1	5,187.2	5,522.6	5,879.9
2	**Reallocation Adjustment**	3	23.1	0.0	0.0	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2 or line 4 + line 5 + line 6)		4,433.1	4,625.1	5,187.2	5,522.6	5,879.9
4	**Used Fuel Fund (Provincial Guarantee Portion)**		2,106.4	2,624.1	2,902.0	3,066.3	3,237.2
5	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	16.5	97.7	174.6
6	**Decommissioning Fund**		2,326.7	2,001.0	2,268.7	2,358.6	2,468.1
7	**Earnings (Losses)** (line 8 + line 9 + line 10)		(183.9)	386.2	268.8	286.2	304.6
8	**Used Fuel Fund (Provincial Guarantee Portion)**		129.7	92.7	149.8	158.2	167.0
9	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	2.9	6.8	10.6
10	**Decommissioning Fund**		(313.6)	293.5	116.2	121.2	126.9
11	**Contributions** (line 12 + line 13 + line 14)		395.0	214.1	113.9	105.5	99.7
12	**Used Fuel Fund (Provincial Guarantee Portion)**		395.0	197.7	35.5	35.5	35.5
13	**Used Fuel Fund (Non Guarantee Portion)**		0.0	16.5	78.4	70.0	64.2
14	**Decommissioning Fund**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements** (line 16 + line 17 + line 18)		(19.0)	(38.2)	(47.3)	(34.4)	(31.2)
16	**Used Fuel Fund (Provincial Guarantee Portion)**		(7.0)	(12.4)	(21.1)	(22.8)	(24.6)
17	**Used Fuel Fund (Non Guarantee Portion)**		0.0	0.0	0.0	0.0	0.0
18	**Decommissioning Fund**		(12.1)	(25.8)	(26.3)	(11.6)	(6.6)
19	**Closing Balance** (line 20 + line 21 + line 22)		4,625.1	5,187.2	5,522.6	5,879.9	6,252.9
20	**Used Fuel Fund (Provincial Guarantee Portion)** (line 4 + line 8 + line 12 + line 16)		2,624.1	2,902.0	3,066.3	3,237.2	3,415.1
21	**Used Fuel Fund (Non Guarantee Portion)** (line 5 + line 9 + line 13 + line 17)		0.0	16.5	97.7	174.6	249.4
22	**Decommissioning Fund** (line 6 + line 10 + line 14 + line 18)		2,001.0	2,268.7	2,358.6	2,468.1	2,588.4

Notes:
1 2008 values are annual amounts.
2 2008 amount per EB-2007-0905 Payment Amounts Order, Appendix A Table 8
3 See Ex. C2-T1-S2 Table 2, Note 7.

VECC Interrogatory #035

Ref: Ex. C2-T1-S2, Table 4

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

Please provide a calculation in the manner of Table 4 for the year 2010. Please describe if and in what manner the 2010 revenue impact of the Darlington Refurbishment project is credited to ratepayers. If it is not credited to ratepayers, please explain why OPG believes it is appropriate for it to retain the surplus funds associated with the impacts of the project on the revenue requirement associated with Nuclear Liabilities.

Response

Attachment 1 is a calculation in the manner of Ex. C2-T1-S2, Table 4 for 2010 which provides the revenue requirement impact of the Darlington Refurbishment project. This table excludes the impacts related to the Bruce facilities as they are already captured in the Bruce Lease Variance Account.

There is no variance account in place that would provide for the return of these amounts to ratepayers. Returning these amounts to ratepayers without a variance account in place would amount to retroactive ratemaking. On this basis, OPG believes it is appropriate that it retain these amounts.

OPG notes that the impact of the Darlington Refurbishment project is one of many elements of costs and revenues for 2010 which do not have variance account treatment. OPG also notes that it has forecast that it will earn a return on equity ("ROE") of 7.8 per cent (Ex. C1-T1-S1, page 3) during 2010, which is less than OPG's approved ROE of 8.65 per cent.

Numbers may not add due to rounding.

Table 4
Revenue Requirement Impact of Adjustment to Nuclear Liabilities Due To Darlington Refurbishment Project ($M)
Years Ending December 31, 2010

Line No.	Description	Note or Reference	With Darlington Refurbishment 2010	Note or Reference	Without Darlington Refurbishment 2010	(a)-(b) Revenue Requirement Impact
			(a)		(b)	(c)
	PRESCRIBED FACILITIES					
1	**Depreciation of Asset Retirement Costs**	Note 1, C2-T1-S2 Table 1	33.2	Note 1, C2-T1-S2 Table 1	123.8	(90.6)
2	**Used Fuel Storage and Disposal Variable Expenses**	C2-T1-S2 Table 1	23.0	Note 2	19.5	3.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	C2-T1-S2 Table 1	1.1	Note 2	1.0	0.0
	Return on ARC in Rate Base:					
4	**Accretion Rate**	C1-T1-S1 Tables 3	86.9	Note 2, 3	58.0	28.9
5	**Weighted Average Cost of Capital**	C2-T1-S2 Table 5	0.0	Note 3	0.0	0.0
6	**Total Revenue Requirement Impact - Prescribed Facilities**		144.2		202.3	(58.1)
	(line 1 + line 2 + line 3 + line 4 + line 5)					

Notes:

1 The 2009 Depreciation Expense would remain unchanged for 2010 to 2012 in the absence of the changes associated with the Darlington Refurbishment Project.

Facilities	2009	2010	(b)-(a) Annual Impact
	(a)	(b)	(c)
Prescribed	123.8	33.2	(90.6)

2 "Without Darlington Refurbishment" numbers are derived from a base case calculation of Asset Retirement Obligation (ARO) and Asset retirement Costs (ARC) before the Darlington ARO adjustment, and are presented for illustrative purposes.

3 The table below presents the revenue requirement impact of accretion rate without the Darlington Refurbishment Project. If the forecast of unfunded nuclear liabilities (total ARO less segregated funds) is lower than the unamortized ARC, then that difference is assumed to be the funded portion of the unamortized ARC. The funded portion earns a return at the weighted average cost of capital (WACC). During the tes period, the unamortized ARC is less than UNL, so none of the unamortized ARC earns the WACC.

Line No.	Description	(2010 amount from Ex. C2-T1-S2 Table 1, line 22, col. (g)) Asset Retirement Cost Opening Balance	(Ex. C2-T1-S2 Table 1 line 26, col. (f)) Depreciation Expense	(a)-(b) Closing Balance	((a)+(c))/2 Gross Plant Rate Base Amount	Average Accretion Rate	(d) x (e) Pre-Tax Revenue Requirement
		(a)	(b)	(c)	(d)	(e)	(f)
	2010 Budget:						
1	Adjustment for Lesser of UNL or ARC	1,098.0	123.8	974.2	1,036.1	5.60%	58.0
	2011 Plan:						
2	Adjustment for Lesser of UNL or ARC	974.2	123.8	850.4	912.3	5.60%	51.1
	2012 Plan:						
3	Adjustment for Lesser of UNL or ARC	850.4	123.8	726.6	788.5	5.60%	44.2

VECC Interrogatory #036

Ref: Ex. C2-T1-S2, Table 5

Issue Number: 8.2
Issue: Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Interrogatory

a) Please reissue Table 5, including the Board approved (as opposed to actual) numbers for 2008, 2009, and 2010, so as to illustrate what was included in rates for 2008, 2009 and 2010. (For example, it appears to VECC that the most significant difference between the actuals that are included in the existing Table 5 and the board approved equivalent for those years is the substitution of actual earnings (losses) on the segregated funds for the forecast that was included in rates, both in the direct calculation of the Revenue Requirement for the Bruce facilities in Table 5 and in the calculation of the unfunded nuclear liability in Table 1, which may affect the calculations at lines 4 and 5 of Table 5.)

b) Please provide a table setting out OPG's actual annual cash outlays related to its nuclear waste management and decommissioning obligation in a manner similar to Table 5. (It appears to VECC that developing such a table would include lines 2, 3, 8 and 9 from Table 5, plus line 15 from Table 1 and line 16 from Table 2.)

Response

a) See Attachment 1.

b) As explained in Ex. L-14-031 part b) OPG does not record or track the expense lines 2, 3, 8, and 9 in Ex. C2-T1-S2, Table 5 by funding sources as this is not required for accounting purposes. Therefore, to illustrate OPG's actual, budget and plan annual cash outlays related to its nuclear waste management and decommissioning obligation, line 7 and line 8 (Expenditures for Used Fuel, Waste Management & Decommissioning) and line 15 and line 16 (Contributions) from Ex. C2-T1-S2 Table 1 and Table 2 respectively were used instead of the line numbers in Table 5 referred to by VECC in part b) above. As described in Notes 4 and 6 in Tables 1 and 2, respectively "Expenditures incurred by OPG relate to both short-term programs (Used Fuel Storage, L&ILW Storage) and long-term programs (Used Fuel Disposal, L&ILW Disposal and Decommissioning), whereas disbursements from Nuclear Segregated Funds cover long-term programs only". Therefore, the difference between the expenditures and Ontario Nuclear Funds Agreement ("ONFA") disbursements is OPG's cash outlays for the short-term programs. Contributions into the nuclear segregated funds represent OPG's cash outlays for the long-term programs. Therefore, the sum of expenditures less ONFA disbursements and contributions into the nuclear segregated funds in any particular year would represent

OPG's annual cash outlays related to its nuclear waste management and decommissioning obligation. These are shown in Attachment 2.

Numbers may not add due to rounding.

ATTACHMENT 1

Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012
Amounts in Evidence for Years Ending December 31, 2008, and 2009

Line No.	Description	2008 - 2009 Board Reference	2008 Evidence nine months	2009 Evidence	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
			Note 1	Note 1	Note 2	Note 2	Note 2
	PRESCRIBED FACILITIES		Note 3				
1	**Depreciation of Asset Retirement Costs**		90.0	120.0	33.2	33.2	33.2
2	**Used Fuel Storage and Disposal Variable Expenses**	Note 4	16.0	23.0	23.0	26.6	28.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	Note 4	0.0	0.0	1.1	0.8	0.8
	Return on Rate Base:						
4	**Accretion Rate**		44.5	56.7	86.9	85.0	83.1
5	**Weighted Average Cost of Capital**	Note 5	6.7	7.8	0.0	0.0	0.0
6	**Total Revenue Requirement Impact**		157.2	207.5	144.2	145.7	145.6
	(line 1 + line 2 + line 3 + line 4 + line 5)						
	BRUCE FACILITIES						
7	**Depreciation of Asset Retirement Costs**		36.0	48.0	28.5	28.5	28.5
8	**Used Fuel Storage and Disposal Variable Expenses**	Note 4	19.0	17.0	16.7	17.0	24.0
9	**Low & Intermediate Level Waste Management Variable Expenses**	Note 3	0.0	0.0	0.9	0.8	0.7
10	**Accretion**		201.0	282.0	282.4	294.5	307.2
11	**Less: Segregated Fund Earnings (Losses)**		176.0	262.0	268.8	286.2	304.6
12	**Return on Rate Base**	Note 2	0.0	0.0	0.0	0.0	0.0
13	**Total Revenue Requirement Impact**		80.0	85.0	59.6	54.5	55.8
	(line 7 + line 8 + line 9 + line 10 - line 11 + line 12)						

Notes:

1 The OEB did not approve the amounts for April 1, 2008 to December 31, 2009 with the excpetion of the accretion rate amounts on Line 4 (Order Appendix A, Table 4b) for 2008 and 5b) for 2009, and the depreciation amount was accepted (Decision, Page 88). The amounts presented are reflected in a Table on Page 69 of the Decision, Section 5.1.3 Financial Reporting.

2 Evidence references for the 2010 to 2012 period are provided in Ex C2-1-2 Table 5.

3 The Board set payment amounts effective April 1, 2008; therefore the 2008 Evidence amounts are provided for the nine month period April 1, 2008 to December 31, 2008 only. Ex. C2-T1-S2 Table 5 includes 12 months for 2008.

4 The 2008 and 2009 Evidence amounts are for nuclear waste variable expenses. Low and Intermediate Waste Management Variable Expenses have therefore been included with Used Fuel Storage and Disposal Variable Expenses.

5 If UNL is less than ARC then the funded ARC earns WACC effective April 1, 2008.

Year	ARC ($M) Order App A Table 4b note 6 Order App A Table 5b note 5	UNL ($M) Ord App A Tbl 4b note 6 Ord App A Tbl 5b note 5	ARC-UNL ($M) (a)-(b)	Annual WACC	Return* ($M) (c)x(d)	WACC Reference
	(a)	(b)	(c)	(d)	(e)	
2008 Post April 1	1,227.0	1,060.3	166.7	5.37%	6.7	Note 2
2009	1,121.0	1,012.9	108.1	7.19%	7.8	Note 2
2010	1,556.5	1,783.5	(227.0)	3.94%	0.0	Note 2
2011	1,523.3	1,695.7	(172.4)	7.56%	0.0	Note 2
2012	1,490.1	1,620.8	(130.7)	7.59%	0.0	Note 2

Numbers may not add due to rounding.

Annual Cash Outlays Related to OPG's Nuclear Waste Management and Decommissioning Obligation ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note or Reference	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	PRESCRIBED FACILITIES						
	Cash Outlays for Long-Term Programs	Note 1					
1	**Contributions to Nuclear Segregated Funds**	C2-T1-S2 Table 1, Line 15	58.9	124.7	150.2	145.0	140.4
	Cash Outlays for Short-Term Programs	Note 2					
2	**Expenditures for Used Fuel, Waste Management & Decommissioning**	C2-T1-S2 Table 1, Line 7	122.6	129.3	157.1	127.3	126.6
3	**Less: Disbursements from Nuclear Segregated Funds**	C2-T1-S2 Table 1, Line 16	62.5	65.7	71.9	46.6	58.0
4	**Subtotal** (Line 2 - Line 3)		60.1	63.6	85.2	80.7	68.6
5	**Total Cash Outlays** (line 1 + line 4)		119.0	188.3	235.4	225.6	209.0
	BRUCE FACILITIES						
	Cash Outlays for Long-Term Programs	Note 1					
6	**Contributions to Nuclear Segregated Funds**	C2-T1-S2 Table 2, Line 16	395.0	214.1	113.9	105.5	99.7
	Cash Outlays for Short-Term Programs (Line 8 - Line 9)	Note 2					
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**	C2-T1-S2 Table 2, Line 8	72.4	62.0	76.8	85.2	85.9
8	**Less: Disbursements from Nuclear Segregated Funds**	C2-T1-S2 Table 2, Line 17	19.0	38.2	47.3	34.4	31.2
9	**Subtotal** (Line 7 - Line 8)		53.3	23.8	29.5	50.8	54.7
10	**Total Cash Outlays** (line 6 + line 9)		448.3	237.9	143.3	156.3	154.3
11	**OPG's Annual Cash Outlays** (line 5 + line 10)		567.3	426.1	378.7	381.9	363.3

Notes
1 OPG's Long-Term Nuclear Waste Management and Decommissioning Programs are Used Fuel Disposal, Low and Intermediate Level Waste Disposal, and Decommissioning.
2 OPG's Short-Term Nuclear Waste Management and Decommissioning Programs are Used Fuel Storage and Low and Intermediate Level Waste Storage.

VECC Interrogatory #037

Ref: Ex. E1-T2-S1

Issue Number: 9.2
Issue: Is the hydroelectric incentive mechanism appropriate?

Interrogatory

a) Please provide a comparison of the historical spreads between the market clearing price (MCP) and the regulated rate as used in the formula for determining the hydroelectric incentive mechanism (HIM) payments.

b) Please provide OPG's expectations as to the relationship between the regulated rate and the MCP over the test period.

c) Please confirm that all else equal, an increase in the regulated rate will increase the HIM.

d) Please explain fully why any incentive mechanism is needed to incent OPG to utilize the pump generating station in the (usual) manner for which it was designed.

Response

a) The table below shows the difference between the average monthly market price and the hydroelectric regulated rate between December 1, 2008 and December 31, 2009.

$/MWh	Average HOEP	Hydroelectric Regulated rate (including rider[1])	Difference (HOEP less Regulated rate)
December 2008	$46.34	$38.84	$7.50
January 2009	$53.22	$38.84	$14.38
February 2009	$47.24	$38.84	$8.40
March 2009	$28.88	$38.84	-$9.96
April 2009	$18.40	$38.84	-$20.44
May 2009	$27.77	$38.84	-$11.07
June 2009	$22.84	$38.84	-$16.00
July 2009	$18.99	$38.84	-$19.85
August 2009	$26.07	$38.84	-$12.77
September 2009	$20.76	$38.84	-$18.08
October 2009	$29.22	$38.84	-$9.62

[1] Payment Rider D, Payment Amounts Order EB-2007-0905, Section 6

November 2009	$26.54	$38.84	-$12.30
December 2009	$35.05	$38.84	-$3.79

b) There is no relationship between the regulated rate and HOEP.

c) There is no relationship between the regulated rate and the hydroelectric incentive mechanism (“HIM”) incremental market revenues.

d) The pump generation station is designed to move energy from periods of low value to periods of higher value. The HIM provides OPG with clear market price signals with which to efficiently and economically assess and base operational decisions. Absent an incentive mechanism based on market price, OPG would rely on the regulated rate for operational decisions. Using the regulated rate exclusively would result in OPG operating its assets with a flatter production profile, relative to a production profile based on market price signals, in order to maximize production. Absent the HIM, a lack of linkage to market price signals could lead to situations where energy that could be transferred to higher value peak hours is not.

A market-based incentive mechanism exposes OPG’s operational decisions to market conditions and the intrinsic financial risk. The HIM is required to incent OPG to assume and manage these market risks.

VECC Interrogatory #038

Ref: Ex. H1-T1-S1, page 8

Issue Number: 10.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

The Board's decision in EB-2009-0038 dated May 11, 2009 determined as follows:

> 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. (emphasis added)

At Exhibit H1, Tab 1, Schedule 1, page 8, OPG asserts the following:

> Since the 2008 - 2009 payment amounts continue in 2010, OPG is forecasting to record an addition of $195.0M in 2010, which is equal to the annualized value (i.e., 12/21) of the $341.2M revenue requirement reduction incorporated in the payment amounts for the 21-month test period from April 1, 2008 – December 31, 2009.

VECC notes that as part of the application (EB-2009-0174) by OPG to extend the operation of certain deferral and variance accounts related to the 2008 and 2009 test period into 2010 no approval was sought or provided specific to the Tax Loss Variance Account established in EB-2009-0038.

Based on the foregoing, please provide the legal basis upon which OPG believes it is entitled to claim relief in the Tax Loss Variance Account based on 2010 payment amounts.

Response

The underlined portion of the OEB's Decision in EB-2009-0038 above does not represent a time limitation for the Tax Loss Variance Account (i.e., for the test period only) as the question suggests. The applicable principle here is beyond dispute. While payment amounts are established based on a test period, they remain in place until changed by the OEB. Similarly, unless the OEB explicitly states otherwise, accounts established in relation to those payment amounts also continue until changed by the OEB.

The continuation of the Tax Loss Variance Account illustrates the operation of this principle. The payments amounts established in EB-2007-0905, which include the identifiable error found in EB-2009-0038, continue into 2010. The Tax Loss Variance Account created by the OEB's Order in EB-2009-0038 to correct this error also continues into 2010 because the OEB's Order does not include an explicit end date for this account.

This principle also underlies OPG's August 12, 2009 submissions in EB-2009-0174. As noted there, OPG did not seek to extend the operation of certain deferral and variance accounts because these accounts already continued past December 31, 2009.