ONTARIO POWER GENERATION INC.
2011-2012 PAYMENT AMOUNTS

EB-2010-0008

Board Staff Submission

November 30, 2010

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1. INTRODUCTION

Ontario Power Generation Inc. ("OPG" or the "Applicant") filed an application, dated May 26, 2010, with the Ontario Energy Board under section 78.1 of the *Ontario Energy Board Act,1998,* S.O. 1998, c.15, Schedule B (the "Act") seeking approval for increases in payment amounts for the output of certain of its generating facilities, to be effective March 1, 2011.

OPG is seeking approval of a revenue requirement of $1,435.7M for the regulated hydroelectric facilities and a revenue requirement of $5,473.9M for the nuclear facilities for the test period January 1, 2011 to December 31, 2012. The major components of the test period revenue requirement are shown in the table below.

$M	**Regulated Hydroelectric**			**Nuclear**		
	2011	**2012**	**Total**	**2011**	**2012**	**Total**
Return on Capital	287.6	287.3	574.9	275.4	284.9	560.3
Expenses	450.9	443.1	894.0	2,508.3	2,602.6	5,110.9
Other Revenue	(44.9)	(46.2)	(91.1)	(160.1)	(167.0)	(327.1)
Income Tax	30.6	27.4	57.9	53.9	75.9	129.8
Revenue Requirement	724.2	711.6	1,435.7	2,677.5	2,796.5	5,473.9
Disposition of Deferral and Variance Accounts	(39.5)	(47.3)	(86.8)	227.1	232.8	459.9
Rate Base	3,803.4	3,787.4		4,041.3	4,150.8	

Source: ExhI1/Tab1/Sch1, Table 1

OPG indicated, in its published Notice of Application, that if the application was approved as filed, there would be an average 6.2% increase in payment amounts. This increase would mean an increase of $1.86 on the monthly total bill for a typical residential customer consuming 800 kWh per month.

In response to the Notice, the Board received five Letters of Comment from individuals across Ontario expressing concern about increases in the cost of electricity. Additionally, two parties applied for, and were granted, observer status. Thirteen parties applied for, and were granted, intervenor status. The Association of Major Power Consumers in Ontario ("AMPCO"), Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe Research Foundation ("Energy

Probe"), Green Energy Coalition ("GEC"), Pollution Probe Foundation ("Pollution Probe"), Power Workers' Union ("PWU"), School Energy Coalition ("SEC"), Society of Energy Professionals ("Society") and Vulnerable Energy Consumers Coalition ("VECC") took active roles in the oral hearing.

The issues list for this proceeding was established on July 21, 2010 and was attached to Procedural Order No. 3. The oral hearing for this proceeding commenced on October 4, 2010 and ended on November 26, 2010. There were sixteen hearing days in total. OPG filed its argument in chief on November 19, 2010.

1.1 Board Staff Submission

This submission reflects observations and concerns which arise from Board staff's review of the oral and written evidence, and is intended to assist the Board in evaluating OPG's application and in setting just and reasonable payment amounts. Not all issues on the Issues List are addressed in this submission. Only those issues which, in Board staff's opinion, require comment or analysis are addressed. The submission contains staff comments on the following topics:

- Capital Structure and Cost of Capital
- Rate Base and Capital Expenditures
- Darlington Refurbishment
- Operating Costs
- Depreciation and Service Life of Stations
- Production Forecast
- Design of Payment Amounts
- Deferral and Variance Accounts
- Reporting and Record Keeping Requirements
- Methodologies for Setting Payment Amounts

2. CAPITAL STRUCTURE AND COST OF CAPITAL

2.1 Capital Structure

OPG has used a deemed capital structure of 53% debt and 47% equity for rate-making purposes. The short-term debt component, of the 53% deemed debt component, is 3.0% in 2011 and 2.9% in 2012[1], respectively.

The deemed capital structure is applied to OPG's rate base for the prescribed hydroelectric and nuclear assets after an adjustment for the lesser of Unfunded Nuclear Liabilities ("UNL") or Asset Retirement Costs ("ARC") (the "Adjustment"). The Adjustment is to fund, over the remaining life of nuclear generation assets, the costs for eventual decommissioning of the nuclear generation assets and storage of nuclear waste. This Adjustment was determined by the Board in its Decision with Reasons in the previous prescribed payments application.[2] For the 2011 and 2012 test years in this Application, the Adjustment accounts for approximately 19% of total assets.

This treatment for the cost of capital of OPG's prescribed hydroelectric and nuclear assets is compliant with the Board's decision in the prior application, EB-2007-0905. Board staff also notes that the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"),[3] issued December 11, 2009, acknowledges that OPG's capital structure, like that of natural gas distributors, will be dealt with on a case-by-case basis.

Thus, on an integrated prescribed assets basis as proposed by OPG, Board staff has no concerns with OPG's proposal for the capital structure for rate-setting purposes. Board staff's submission on the capital structure for separate technology-specific costs of capital, if that option is adopted by the Board, is dealt with later in this submission.

2.2 Short-term Debt

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[1] ExhC1/Tab1/Sch1/Tables 1 and 2
[2] Decision with Reasons, EB-2007-0905, November 3, 2008, p88-92
[3] Report of the Board, EB-2009-0084

OPG has documented its short-term ("ST") debt rate in ExhC1/Tab1/Sch3. OPG notes that its ST debt financing consists primarily of two components: a commercial paper program, and its accounts receivable ("A/R") securitization. Each component has a separate rate and derivation.

The A/R securitization is an estimated amount based on $250M in each of the 2011 and 2012 test years, with the rate based on a bankers' acceptance ("BA") rate for OPG plus 0.775%.[4] Included in this is a spread over BA of 20 basis points. For 2011 OPG has forecasted the ST debt rate for A/R securitization at 2.77%, and at 4.26% for 2012.[5]

For the commercial paper ST debt rate, OPG documents its rate as being based on the BA rate plus 10 basis points (for dealer fees) plus a spread of 5 basis points over the BA rate. OPG has estimated ST rates for the commercial paper program of 1.94% for 2011 and 3.43% for 2012. OPG documents that it used data from Global Insights in December 2009 to estimate the forecasted rates for 2011 and 2012. Global Insights, an economic forecasting consulting firm, is used instead of *Consensus Forecasts.* OPG stated that is uses Global Insights because it provides forecasts more than 12 months out. Board staff notes that the *Consensus Forecasts* publication has been used by the Board for formulaic setting of cost of capital for over a decade.

OPG's methodology adheres with the approach used in the previous case. The Cost of Capital Report also acknowledges that OPG's ST debt is forecasted by the utility.

However, when questioned by Board staff, OPG indicated that it is not proposing to update its ST debt rate at the time of the decision. OPG has filed information in accordance with its business plan. The OPG witness commented that a proposal to update ST debt rate could be viewed by intervenors as "cherry-picking".[6]

Board staff submits that updating the Return on Equity ("ROE") and long-term debt rate but not updating the ST debt rate is in fact "cherry-picking", and is inconsistent with the Board's policy and practice.

[4] ExhC1/Tab1/Sch3/p3
[5] ExhC1/Tab1/Sch3/Table 2
[6] Tr. Vol. 12, p103/ln15-23

Cost of capital is different from other components of Cost of Service in that it is always prospective. While rate base and operating expenses can be on a forward or historical test year basis, the cost of capital is tied to the rate period for which rates are being set – i.e., on a prospective basis. The formulaic methodologies employed by the Board, and by some other Canadian regulators, try to use economic data that is independent and reputable to estimate the cost of capital parameters for the prospective test period for which rates are being set, as this represents the best information currently available to set rates that meet the Fair Return Standard and afford investors the opportunity to earn commensurate with what they might otherwise have an opportunity to earn on an investment of like risk.

The adoption of using data three months in advance of the effective date, as is the Board's policy and practice as documented in the Cost of Capital Report and predecessor documents attempts to balance theory and practicality. Data as close to the test period as possible should be used as it is probably a better forecast, with a smaller probabilistic range of error than an older forecast. *Consensus Forecasts* contains forecasts 3 months and 12 months out from the publication month, and so effectively covers the start and as late a period in the test year as is available in that publication. Using data three months in advance of the effective date is also practical in terms of having the updated parameters available for the Board's decision and a subsequent draft rate order process.

Board staff is concerned with OPG's approach of not updating the ST debt rate along with the ROE and deemed long-term debt rate. While macroeconomic factors will influence all three parameters differently, all three factors are influenced by what occurs in the market. All three parameters are affected and should reflect the most current information available. This is the policy as documented in the Cost of Capital Report, which states that all three parameters are updated based on data three months in advance of the effective date. The Board has adhered to this approach in updating all three parameters simultaneously; this is most recently reflected in its letter of November 15, 2010 on updated Cost of Capital parameters for 2011 Cost of Service rate applications effective January 1, 2011.[7]

Board staff submits that, while OPG has its own methodologies for updating the ST debt rates for the two components of its ST debt, the A/R securitization rate and the

[7] http://www.oeb.gov.on.ca/OEB/_Documents/2011EDR/Ltr_Jan1st_Cost_of_Capital_Parameters_20101115.pdf

commercial paper rate, it should update the rates to reflect more current data. Consistent with the update of the ROE and, if applicable, the deemed long term debt rate, OPG should update the two ST debt rates using its documented methodologies and data three months in advance of the effective date of rates (i.e. November 2010 for March 1, 2011 payment amounts). OPG should provide documentation on the parameter calculation and source data used in the update of these rates.

2.3 Long-term Debt

OPG has documented its long-term ("LT") debt in ExhC1/Tab1/Sch2. OPG has documented its existing and forecasted debt in each of the 2011 and 2012 test years. OPG's debt is held by third-parties.

With the exception of OPG's proposed treatment of the unfunded portion of its deemed capital structure (the "notional debt"), Board staff makes no submission on OPG's actual and forecasted debt in the 2011 and 2012 test years, and submits that the proposed treatment of its actual and forecasted debt is compliant with the Cost of Capital Report.

2.3.1 Notional Debt

In ExhC1/Tab 1/Sch 1/Tables 1 and 2, OPG shows separately an unfunded portion of LT debt. This unfunded portion is the difference between the deemed LT debt, calculated as 53% minus short-term debt, and OPG's actual or forecasted LT debt. As acknowledged by its response to a Board staff interrogatory,[8] the unfunded portion of LT debt is equivalent to what the Board has termed "notional debt".

In its application, OPG has proposed to use the Board's deemed LT debt rate as the cost for this unfunded debt portion. In response to questioning on this treatment, OPG has maintained this proposed treatment throughout the proceeding. OPG's rationale for applying the deemed LT debt rate is its interpretation of the Cost of Capital Report, which states:

[8] Issue 3.2, ExhL/Tab1/Sch14 part a

> The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.[9]

OPG has interpreted "where" to mean "for that portion of deemed debt not actually covered by actual debt". In other words, the unfunded or notional debt is a "plug" to match the deemed debt to actual debt capitalization. A similar concept is used in the Board's regulation of natural gas distribution with respect to short term debt, but this has not been adopted for the electricity distribution sector due in large part to the larger number of electricity distributors and the greater variability of debt and equity capitalization observed in that sector.

Instead the Board's policy and practice is different than OPG's interpretation. In various electricity distribution and transmission decisions, cited in staff interrogatory #14, the Board has consistently rejected notional debt attracting the deemed debt rate, except where the utility has absolutely no debt. One instance where the Board has used the deemed debt rate was for Tillsonburg Hydro Inc., in its 2009 Cost of Service application considered under File No. EB-2008-0246. Tillsonburg Hydro Inc. is 100% equity financed and had no, nor any history of, debt financing at the time of its application. The Board found that it would use the deemed LT debt rate in the absence of any evidence of the cost of debt.[10] That, Board staff submits, is the "where" referenced in the Cost of Capital Report – "where" means those circumstances in which a utility has no actual debt and hence there is no other evidence of the cost of borrowing of the utility in the past or at present.

However, OPG does have debt, and there is evidence of its weighted average cost of long-term debt for existing and forecasted debt instruments in the 2011 and 2012 test years. In the Decisions referenced in staff interrogatory #14, referring to the treatment of notional debt, the Board has routinely determined that the full deemed debt, including the unfunded or notional debt, should attract the weighted average cost of actual and forecasted debt, and the deemed debt rate is used as a last resort in those instances where there is no evidence or history of debt financing by the utility.

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[9] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009, p54

[10] Decision, EB-2008-0246, July 10, 2009, p32-33.

In response to part (b) of staff interrogatory #14, OPG stated that the Board's determinations cited are superseded by the Cost of Capital Report, which was issued subsequent to the referenced decisions. Board staff submits that the Board's treatment of notional or unfunded debt did not change with the new Cost of Capital Report. Admittedly, Board staff are unaware of any Board decisions since the Cost of Capital Report was issued in December 2009 where notional or unfunded debt was at issue. However, in other decisions on cost of service applications for electricity distribution rates in 2010, the Board has routinely approved the use of the actual weighted average cost of long term debt (in the test year) for the deemed debt long term debt capitalization of 56%. In many cases, the distributor is underleveraged, having significantly more equity (through both shares and retained earnings) than the deemed 40% equity thickness. As a result, it has less actual long-term debt than 56% of its rate base. Thus, there is implicitly a portion of the 56% deemed LT debt capitalization that is unfunded by actual debt. In applying the weighted average cost of LT debt based on actual and forecasted debt in the test year, the Board is implicitly applying this rate, and not the deemed debt rate, to the unfunded or notional debt as well as to the utility's actual debt.

Therefore, Board staff submits that OPG's interpretation of the Cost of Capital Report is inconsistent with the Board's policy and practice. OPG's forecasted weighted average cost of long-term debt should apply to the Unfunded Portion of debt in each of the 2011 and 2012 test years, instead of the deemed debt rate.

Finally, Board staff notes that OPG's proposal is to its disadvantage. The deemed LT debt rate of 5.87% was for the 2010 test year, as published in the Board's letter of February 24, 2010, and was subject to updating in accordance with the Cost of Capital Report. As noted previously, on November 15, 2010, the Board issued a letter advising of the updated Cost of Capital parameters for 2011 Cost of Service applications with rates effective January 1, 2011. The updated deemed LT debt rate is 5.48%, lower (marginally) than the weighted average cost of OPG's LT debt, estimated as 5.53% for 2011 and 5.50% for 2012.[11] Board staff submits that the use of the weighted average cost of LT debt is the appropriate rate to use based on the Board's documented policy and practice. However, in consideration of the bill impacts on Ontario's electricity ratepayers, the Board may wish to consider accepting OPG's proposal in this application.

[11] ExhC1/Tab1/Sch1/Tables 1 and 2

2.1.4 Return on Equity

The ROE approved for OPG's payment amounts in its prior application, is 8.65% In its current application, OPG has used an ROE of 9.85%, as published by the Board on February 24, 2010 for cost of service applications in 2010 and based on January 2010 data from the Bank of Canada, *Consensus Forecasts* and Bloomberg LLP. The Board uses an approach where the ROE is calculated by a formula, and differences in business risk are reflected in different capital structures.

OPG has acknowledged that the ROE should be updated at the time of the Board's decision based on data from the Bank of Canada, *Consensus Forecasts* and Bloomberg LLP three months in advance of the effective date of rates. OPG has proposed an effective date of March 1, 2011. This would mean that data from the month of November 2010 would be used to update the ROE for the 2011 test year. Board staff submits that OPG's proposal is compliant with the Cost of Capital Report for the 2011 test year.

OPG has also proposed that the revenue requirement for the 2012 test year also be established at the time of this decision, and the approved prescribed payments reflect the combined (averaged) payments amounts for 2011 and 2012 test years.

As the *Consensus Forecast* data used for updating the cost of capital parameters only reflects forecasts 12 months out, OPG has proposed to use forecasts from Global Insights for the 2012 test year. Global Insights is in fact one of the data sources used for the *Consensus Forecasts* forecast. OPG's proposal to calculate the 2012 test year ROE adheres to the Board's formula as documented in Appendix B of the Cost of Capital Report, but would substitute the 2012 Global Insights forecast for *Consensus Forecasts* data, which does not forecast out that far.

OPG is not proposing that there would be an update closer to the 2012 test year, as is the Board's policy and practice. In Toronto Hydro-Electric System Limited's ("THESL's") 2008 rates application covering test years for 2008, 2009 and 2010, the Board accepted in its Decision a 2-year period test period (2008 and 2009).[12] However, the Board

[12] ExhK12.2, p5-6 (Excerpt from p70-71 of the EB-2007-0680 Board Decision, May 15, 2008)

approved rates only for the 2008 test year in that decision. In 2009, THESL was required to file an application in March to update its 2009 revenue requirement and distribution rates to reflect the updated cost of capital parameters. The Board considered the application in an expedited proceeding and rendered its decision following a one-day oral hearing on April 3, 2009.[13]

More recently, the Board approved a two-year Cost of Service application for Hydro One Networks distribution for the 2010 and 2011 test years. And, similar to the decision for THESL, the Board approved the rates for the 2010 test year, and directed Hydro One Networks to file a revenue requirement update for 2011 distribution rates.[14] The Hydro One Networks case was discussed at the oral hearing for this application on October 28, 2010.[15] Hydro One Networks filed the application to update the revenue requirement and distribution rates for 2011 on November 29, 2010. While this matter is before the Board the application is intended to be formulaic in nature and will likely be processed in an expedited manner.

The Board's policy and practice in this regard is to ensure that the rates approved in the test year reflect current information on the cost of capital and macroeconomic conditions. While it is possible to get forecasts that are further out than one year, the margin of error of extended forecasts increases, reflecting imprecision in the relationships between drivers of the forecasts and the fact that conditions can change over time. The increased "forecasting error" inherent in forecasts extending further forward in time limits their informational utility. *Consensus Forecasts* restricts its normal forecasts to three months and 12 months out to increase the informational value of the forecasts by ensuring that forecasting error is not too large. The calculation of the ROE for a test year period of one year adopts this philosophy to ensure that the prospective test year ROE has reasonable precision.

In cross examination on October 28, 2010, the OPG witness acknowledged that the further out one forecasts, the less precise the estimate is. The witness indicated that OPG would be willing to apply for an update for 2012, and also suggested that a deferral or variance account could be established, whichever the Board found most

[13] EB-2009-0069, April 3, 2009,Tr. p128/ln28 to p134/ln11
[14] ExhK12.2, p2-3 (Excerpt from p50-51 of the EB-2009-0096 Board Decision, April 9, 2010)
[15] Tr. Vol. 12, p101-102

expedient.[16]

Board staff submits that a deferral or variance account to deal with differences in the cost of capital “forecasts” is not warranted; such an approach ascribes precision to the Cost of Capital estimates that is not supportable.

While there would be a cost to a subsequent regulatory proceeding to set 2012 payment amounts based on updated cost of capital parameters established based on data for the month of September 2011[17], such an approach would result in more precise estimates that the Board and all parties could have greater confidence in. This is the reasoning that the Board has adopted in the previous 2-year cost of service applications for THESL and Hydro One Networks.

While the Board in the previous payments case did accept a two-year test period for OPG, the ROE was set based solely on expert evidence. Also, the ROE was set in the Board’s decision on November 8, 2008, which was significantly along in the test period from April 1, 2008 to December 31, 2009, and when the ROE of 8.65% could be assessed against actuals and forecasts covering most of the previous test period. These circumstances do not prevail in the current application. The Board has subsequently reviewed the cost of capital applicable to all Ontario energy sectors that it regulates and established updated guidelines in the Cost of Capital Report; these guidelines are applicable to OPG’s prescribed assets.

Therefore, Board staff submits that prescribed payment amounts for the 2011 test year only (i.e. March 1 to December 31, 2011) should be approved at this time. Prior to the 2012 test year, OPG should file an update for the 2012 revenue requirement and prescribed payments based on updated cost of capital parameters. This would be a formulaic update of the cost of capital parameters, and associated taxes/PILs, while operating expenses and rate base would be held constant at the 2012 levels approved by the Board in this decision, and could be dealt with in an expedited manner. Having

[16] Ibid., p98

[17] Per the methodology in the Cost of Capital Report, cost of capital parameters are calculated based on data from the Bank of Canada, Consensus Forecasts and Bloomberg LLP three months in advance of the effective date for the rates. For OPG’s prescribed payments effective March 1, 2011, data from November 2010 will be used. For the 2012 test year covering January 1 to December 31, 2012, the updated parameters will use data from September 2011 – three months in advance of January 1, 2012.

different payment amounts for the different test years would also better align rate recovery to the costs being recovered in each test year.

As discussed earlier, the 2012 update would be for all cost of capital parameters – the ST debt rate, the deemed LT debt rate, as applicable, in addition to the ROE.

2.5 Technology-Specific Cost of Capital

In the Board's Decision with Reasons in the previous proceeding, the Board found that there may be merit in establishing separate capital structures for the regulated hydroelectric and nuclear businesses. The Board concluded that investigation of separate capital structures, but the same ROE, would be explored in the next proceeding. [18]

In response to the Board's findings in the previous proceeding, OPG commissioned a study by Ms. Kathleen McShane of Foster Associates, Inc. to investigate and estimate, if possible, technology-specific costs of capital and specifically capital structures specific to OPG's separate regulated hydroelectric and nuclear generation. Ms. McShane's study is filed as ExhC3/Tab 1/Sch 1.

Ms. McShane acknowledged that the business risks, and hence the capital structures appropriate to reflect compensatory costs of capital would be expected to be different for nuclear and hydroelectric, with nuclear being more risky. There is general agreement in this proceeding, as there was in the previous proceeding on this conceptual premise.

Ms. McShane's approach was to try to estimate, through a variety of methods, estimates of the cost of capital for firms with concentrations of hydroelectric and nuclear generation similar to OPG and for which market data is available. The variety of methods employed by Ms. McShane include the accounting beta, pure play, instrumental beta, residual beta and full information beta. All of these approaches, except for pure play, are based on the Capital Asset Pricing Model, which has been long used for cost of capital analysis in regulated sectors, including the gas and electricity sectors in Ontario.

[18] Decision with Reasons, EB-2007-0905, p160-161

However, Ms. McShane concludes that she is unable to obtain robust estimates of technology-specific costs of capital from any of these approaches. In large part, this is due to the lack of proxy firms in North America which have hydroelectric and nuclear generation concentrations similar to OPG. Ms. McShane notes that there are no publicly traded Canadian utilities analogous to OPG. In response to a Board staff interrogatory[19], Ms. McShane explained why utilities outside of North America were not examined and may not provide information that could be relatable to OPG's situation; Board staff accepts Ms. McShane's explanation.

Pollution Probe's witnesses, Drs. Kryzanowski and Roberts, filed evidence and took a contrary position to Ms. McShane. In their approach, they used a more qualitative assessment to assess the different business risks of nuclear and hydroelectric generation, relative to transmission and distribution "wires" utilities and to an integrated utility.[20]

Under cross examination by OPG's counsel, Drs. Kryzanowski and Roberts defended their qualitative approach:

> MR. SMITH: And that's why, I guess, you would say it is an exercise in qualitative judgment, and reasonable people can disagree?
> DR. ROBERTS: That's correct. And in our evidence -- I can point you to it if you wish -- there are quotes from this Board and from the Commission in Alberta saying just that, that it is a matter of judgment and that is how they determined the capital structure.[21]

Board staff disagrees with Drs. Kryzanowski and Roberts' confidence in and reliance on their qualitative analysis. As was discussed at some length during the oral hearing[22], their qualitative assessment of the relative risk of OPG's nuclear and hydroelectric operations, relative to transmission, distribution and integrated (wires/generation)

[19] Issue 3.3, ExhL/Tab1/Sch17
[20] Tr. Vol. 12, p142/ln7-20
[21] Ibid., p170/ln12-19
[22] Ibid., p129-190

utilities is central to their study. Their qualitative scorings are documented in Schedule 5.1 of their evidence.[23]

In interrogatories, Board staff and OPG questioned Drs. Kryzanowski and Roberts on the lack of weightings in their analysis.[24] Board staff also questioned Drs. Kryzanowski and Roberts[25] on why factors such as "Technology", "Capacity" and "Asset retirement/construction" should be rated as "1" (Low [risk]) for transmission and distribution utilities due to operating requirements and risks that might arise due to the *Green Energy and Green Economy Act*, for instance. Acknowledging that an increase in the score of any of these components would narrow the gap between wires companies and OPG's operating divisions, Drs. Kryzanowski and Roberts stated that they had not done a detailed analysis, and that it goes beyond the scope of their evidence.

Board staff submits that the kind of economic analysis appropriate – and needed – here is both an art and a science. Ms. McShane has attempted a more "scientific" approach to try to develop rigorous estimates of technology-specific costs of capital, and specifically technology-specific capital structures. That she has been unable to do so is more due to a paucity of data and proxy utilities comparable to OPG, than it is a refutation of the hypothesis that there are different risks and hence different costs of capital (to be reflected as different capital structures) for regulated hydroelectric and nuclear.

Drs. Kryzanowski and Roberts have come to a different conclusion, and have developed different estimates of the cost of capital and capital structures for regulated hydroelectric and nuclear. However, their approach is much more reliant on qualitative or heuristic judgment. As noted above, even if there is general agreement on the general approach and the direction of the relative risks of wires companies, hydroelectric and nuclear generation, there could be some differences in the relative risk if the analysis was undertaken by other experts. And there is little actual data to support Drs. Kryzanowski and Roberts' conclusions and estimates.

[23] ExhM/Tab10/p84-86
[24] ExhM/Tab10.1/Sch4 and ExhM/Tab10.15/Sch13
[25] ExhM/Tab10.1/Sch4 b) iii) and iv)

As an administrative tribunal, the Board must make its findings with reference to and be supportable by the record. Board staff believes that the Panel in the previous proceeding wished to investigate if different costs of capital for the two regulated generation technologies existed, and if so, could they be reasonably estimated. This is also the issue that the Board Panel must consider in the current application. The Board Panel must consider whether the evidence on the record, whether derived from econometric analysis or based on expert judgment, is sufficient to distinguish and, if so, to estimate technology-specific costs of capital with sufficient confidence that any technology-specific estimates are adequately supported.

2.6 Technology-Specific Cost of Debt

In the event that the Board decides to adopt technology-specific costs of capital for each of the regulated hydroelectric and nuclear businesses, Board staff provides the following comments on the treatment of debt between the divisions.

OPG establishes separate rate bases and revenue requirements for hydroelectric and nuclear prescribed assets, and calculates separate payment amounts to recover the revenue requirement for each business.[26] The cost of capital is treated the same for each currently, with the exception of the Adjustment for the Lesser of Asset Retirement Costs or Unfunded Nuclear Liabilities. The Adjustment is only applied to the nuclear rate base. Board staff agrees that this is the appropriate treatment for the Adjustment. This approach was determined by the Board in the previous proceeding, and OPG has adhered to this approach in the current application.

Further, while accepting that the Adjustment is different from the usual debt or equity financing of a utility's investments, Board staff submits that the Adjustment is treated as a form of debt financing. Board staff observes that Ms. McShane has assumed that the Adjustment is not a form of equity financing in her prefiled evidence:

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[26] OPG shows the cost of capital on an integrated basis in ExhC1/Tab1/Sch1/Tables 1 to 6 covering, respectively, the 2012 and 2011 test years, 2010 bridge year, and 2009, 2008 and 2007 actuals. However, ExhC1/Tab1/Sch1/Table 7 shows the breakout of the cost of capital between regulated hydroelectric and nuclear. Also, ExhI1/Tab1/Sch1/Table 1 "Summary of Revenue Requirement" clearly shows the separation of rate base and cost of capital between regulated hydroelectric and nuclear for the 2011 and 2012 test years.

> The approach adopted by the Board results in a materially lower effective equity ratio for the prescribed assets in 2010 than the 47% approved by the Board. If the lesser of the unamortized ARC or the UNL is included as a form of financing in the capital structure, the equity ratio for the composite prescribed assets is approximately 40%, compared to the 47% equity ratio adopted by the Board. For the nuclear assets on a stand-alone basis, the differential between the 47% approved equity ratio and the effective equity ratio is considerably larger; the equity ratio including the lesser of the ARC or UNL in capital structure is 32%.[27]

As noted above, the Adjustment is fully allocated to the nuclear business for the purposes of determining the cost of capital and revenue requirement for each of the regulated hydroelectric and nuclear payment amounts.

Board staff submits that this approach should also be extended to other debt of OPG, where applicable. In other words, where debt can be directly identifiable as being attributable to either nuclear or regulated hydroelectric, then this direct allocation of debt to one generating technology should be done. Drs. Kryzanowski and Roberts concurred with this:

> MR. MILLAR: But you are not proposing any other differences in the cost of capital as between hydro and nuclear?
> DR. KRYZANOWSKI: We didn't, but we alluded to the fact that the debt rates would probably be different. That's another step that one could take.
> MR. MILLAR: Okay. So I will put the question directly to you, then. To the extent that long-term debt instruments can be assigned separately to nuclear and hydro, in your view, should we assign different long-term debt rates to nuclear and hydro, if you can do that exercise?
> DR. KRYZANOWSKI: If you could do the exercise? Yes.

[27] ExhC3/Tab1/Sch1/p32 - With the adjustment for the lesser of ARC or UNL comprising about 19% of the rate base, and applying the deemed capital structure to the remainder, the 47% equity of the deemed capital structure is (47% X 81%) ≅ 40% of the total rate base, including the adjustment for the lesser of ARC or UNL, as noted by Ms. McShane.

> MR. MILLAR: And I take it you would find that to be consistent with your view on -- as you expressed in your report; in other words, looking kind of on a stand-alone principle, nuclear versus hydro, and allocating the costs appropriately?
> DR. KRYZANOWSKI: That is correct.[28]

When cross-examined by Board staff,[29] OPG's witnesses concurred that certain debt instruments, labeled "Niagara X" in ExhC1/Tab 1/Sch 2/Tables 6 and 7 are related to hydroelectric projects (for the Niagara Tunnel), but stated that "the debt rate itself actually reflects the rate of the risk profile of the corporation. … the debt rate itself is not a project-specific rate. The debt is actually drawn to fund the project, but the rate itself reflects the corporation's risk profile, not specific to the project risk."[30]

Board staff disagrees with OPG's premise that the debt rates of the "Niagara X" debt instruments solely reflect OPG's corporate risk. In ExhC1/Tab1/Sch 2/p8-9, under section 4.4 "Planned Project-related Long-term Debt Issues", OPG documents the agreement with the OEFC to provide debt financing for the Niagara Tunnel project. OPG notes that it can borrow up to $1B under the current arrangement, and is pursuing an amendment to the agreement to increase the maximum amount that can be borrowed to $1.6B. OPG states that it has partially hedged all expected debt issues in the 2010-2012 period.

Board staff's reading of OPG's evidence would suggest that the funding arrangement with the OEFC for the Niagara Tunnel reflects project-specific risk in addition to OPG's corporate risk. This is what would generally be expected in the market. Where an individual or a firm goes to a financial institution for a loan, the rate offered will depend on the purpose and risk of the loan as well as on the creditworthiness of the person or firm.

Therefore, Board staff submits that, where debt instruments can be directly assignable to either nuclear or regulated hydroelectric, then OPG should do so. General corporate debt financing can be allocated to both divisions, as is currently done. Direct allocation, where appropriate, is consistent with the "stand-alone" principle and consistent with the assignment of the adjustment for the lesser of ARC or UNL solely to the nuclear

[28] Tr. Vol. 12, p155/ln2-21
[29] Ibid., p107/ln12 to p109/ln14
[30] Ibid., p109/ln5-11

business. With the debt instruments identified by OPG in its evidence, Board staff also submits that the direct allocation, where appropriate, should be easily done.

Since OPG already treats regulated hydroelectric and nuclear separately for determining the rate base and revenue requirement and the associated payment amounts, it would also be appropriate to apply this differential treatment of debt between regulated hydroelectric and nuclear even on the existing "integrated" approach. However, it is not clear that this would materially affect the revenue requirement and the associated payments with the common deemed capital structure.

However, should the Board adopt different technology-specific costs of capital, Board staff submits that differentiating debt on a technology-specific basis should be done as well.

3. RATE BASE AND CAPITAL EXPENDITURES

OPG is seeking approval of (i) its hydroelectric rate base for 2011 and 2012 in the amounts of $3,803.4M and $3,787.4M respectively and (ii) its nuclear rate base for 2011 and 2012 in the amounts of $2,518.0M and $2,660.7M respectively. For purposes of this part of the submission, the nuclear rate base excludes the amount recorded for the lesser of Unfunded Nuclear Liability or unamortized Assets Retirement ("unamortized ARC"). [31] These data are illustrated in the table below.

[31] Issue 2.1, ExhL/Tab1/Sch2

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	2007 Actual	2008 Board-approved	2008 Actual	2008 variance (c-b)	2009 Board-approved	2009 Actual	2009 variance (f-e)	2010 Budget	2011 Test Year	2012 Test Year
HydroElectric										
Gross plant at cost	4,396.5	4,433.2	4,416.8	**(16.4)**	4,480.6	4,438.6	**(42.1)**	4,485.0	4,538.0	4,585.5
Accumulated depreciation	507.8	570.2	569.5	**(0.7)**	633.1	631.2	**(1.9)**	693.6	756.7	820.2
Net Plant	**3,888.7**	**3,857.8**	**3,847.3**	**(10.5)**	**3,847.5**	**3,807.4**	**(40.2)**	**3,791.4**	**3,781.3**	**3,765.3**
Cash Working Capital	21.8	21.8	23.6	**1.8**	21.8	26.0	**4.2**	23.7	21.5	21.5
Materials & Supplies	0.6	0.6	0.6	**0.0**	0.6	0.7	**0.0**	0.7	0.6	0.6
Hydroelectric Rate Base	**3,911.1**	**3,880.2**	**3,871.5**	**(8.7)**	**3,869.9**	**3,834.0**	**(35.9)**	**3,815.7**	**3,803.4**	**3,787.4**
Variance - %				-0.2%			-0.9%			
Nuclear										
Gross plant at cost	4,321.1	4,525.5	4,498.9	**(26.6)**	4,733.2	4,679.5	**(53.7)**	5,355.3	5,547.1	5,741.7
Accumulated depreciation	1,446.1	1,737.8	1,733.0	**(4.8)**	2,037.1	2,023.7	**(13.5)**	2,278.8	2,500.3	2,745.4
Darlington Refurbishment (CWIP)									125.5	306.0
Net Plant	**2,875.0**	**2,787.7**	**2,765.9**	**(21.8)**	**2,696.0**	**2,655.8**	**(40.2)**	**3,076.5**	**3,172.2**	**3,302.3**
Cash Working Capital	16.0	16.0	15.9	**(0.1)**	16.0	14.3	**(1.7)**	9.2	4.0	4.0
Fuel Inventory	208.7	281.1	266.9	**(14.3)**	330.1	316.9	**(13.3)**	357.3	379.8	360.9
Materials & Supplies	400.4	424.4	415.6	**(8.8)**	441.7	434.4	**(7.3)**	468.9	485.3	483.7
Total Working Capital	**625.1**	**721.5**	**698.4**	**(23.1)**	**787.8**	**765.6**	**(22.3)**	**835.5**	**869.1**	**848.5**
Nuclear Rate Base	3,500.1	3,509.1	3,464.2	**(44.9)**	3,483.8	3,421.4	**(62.4)**	3,912.0	4,041.3	4,150.8
				-1.3%			**-1.8%**			
Nuclear Rate Base without "Unamortized ARC"	2,084.7	2,282.1	2,180.5	**(101.6)**	2,362.8	2,261.6	**(101.2)**	2,355.4	2,518.0	2,660.7
Variance - %				**-4.5%**			**-4.3%**			

Source: Issue 2.1, ExhL/Tab1/Sch2

Board staff submits that the Board should reduce OPG's hydroelectric 2011 and 2012 rate base by $12.0M in each year and its nuclear 2011 and 2012 rate base by $128M and $161M respectively.

3.1 Hydroelectric Rate Base

Board staff's submission under Hydroelectric Capital Projects calls for the removal of $12.0M related to the St. Lawrence Visitor Centre at the Saunders Generating Station from the 2011 and 2012 rate base. See page 22 of this submission.

3.2 Nuclear Rate Base

OPG's witness under cross-examination confirmed that the nuclear rate base approved in the EB-2007-0905 Decision for 2008 and 2009 was over-forecasted by 4.3% and

4.5% respectively, or approximately $101M.[32] Of the $101M variance approximately $23M was working capital related and $78M was plant related. When asked whether OPG had made changes to their forecasting to prevent this from happening again, the witness, while noting that "….we implore each year to seek improved accuracy from the business units", stated that there were no formal policy changes or anything of that nature.[33] The witness explained that the rate at which plant is brought into service and the rate at which it is depreciated contributed to the variance.

Exhibit KT1.6 shows that the overstated rate base resulted in over-earnings of $5.4M in 2008 and $7.3M in 2009, not including the affects on taxes and depreciation.

With respect to 2010 capital expenditures, OPG's witness testified that he expected 2010 actuals to come in within 10% of the budget or $160M compared with the capital budget of $172M for the nuclear project portfolio.[34] Based on this projection, Board staff submits that the 2011 and 2012 proposed rate base should be reduced by $6.0M and $12.0M respectively. In calculating the reduction to rate base, Board staff assumed that the full "in-service" impact occurs in 2012.

The proposed rate base for 2011 and 2012 reflects historical capital expenditures, net of accumulated depreciation, as well as new capital that will close to service. Board staff question the level of nuclear new capital planned for 2011 and 2012. For example, the business planning process did not include re-iterative steps cognizant of rate impacts and the shareholder expectations regarding cost control. OPG has confirmed that during the preparation of its 2011 and 2012 application, not a single capital project was reprioritized.[35] From a corporate perspective as long as projects can be funded through operating cash flow, there does not appear to be a provision in the business planning process to consider reducing the expenditures; "…..We have not looked specifically at the need to reduce these. We have left this really at the business unit level to deal with, to identify the work that is required, to identify -- to sustain the assets properly." [36]

[32] Tr. Vol. 10, p159/ln17-25
[33] Ibid., p161/ln1-19
[34] Tr. Vol. 5, p124/ln3-11
[35] Issue 2.1, ExhL/Tab1/Sch5
[36] Tr. Vol. 10, p168/ln 3-6

In any event, OPG admitted that, "A large focus of the context of the past planning process dealt with trying to minimize the operating costs of operating the system."[37] OPG explained that for capital, the business planning process is different since business units are provided "envelopes" of dollars and as long as the list of projects (from the project portfolio), that are to sustain the reliability and safety of the units doesn't exceed the envelope total, no constraint is considered or required. OPG further stated that as long as the cash is available, say, through depreciation, the company works through a list of projects, replacing some that are found to be wanting, with others. As well such projects are not subject to an economic cost-benefit analysis as would be the case for investments directly affecting generation output.[38]

OPG's testimony during Board staff's cross examination on the Feeder Repair by Weld Overlay at Darlington Project and the Maintenance Facility at Darlington Project is illustrative of the limitations of OPG's business planning approach especially during times of economic constraint and rising rates.

OPG's proposed 2011 rate base includes $43M (excluding contingency of $13M) in forecasted capital expenditures for the Feeder Repair by Weld Overlay at Darlington Project. OPG confirmed that the project was deferred beyond the test period. When questioned whether OPG's revenue requirement should be adjusted for this, the witness responded that OPG would not propose a reduction because another "high priority" project would replace it. The witness confirmed that the particulars of the "replacement" do not form part of the evidence in this proceeding.[39] In addition to the conclusion that OPG may be missing opportunities to reduce its 2011 and 2012 revenue requirement, Board staff question OPG's automatic conclusion that it is appropriate to substitute one project with another, particularly in cases where the replacement project does not form part of the application. Board staff notes that OPG considers the substituting project to be a "high priority", however the project did not make the "approved" list the first time around. This indicates to Board staff that the 'project' was not required in the test period.

OPG's proposed 2012 rate base also includes $20M for the Maintenance Facility at Darlington Project which OPG confirmed won't close to rate base until 2013. OPG's witness indicated that the project was revamped (planned location changed from within

[37] Ibid., p166/ln 21-25.
[38] Tr. Vol. 5, p119-120
[39] Ibid., p136

to outside the protected area) which affected both the cost and in-service timing. The witness testified that $25-30M of the $50M project could be useable, and as such closed to rate base. With respect to the “balance” that remains in the rate base for the test years, the witness reiterated OPG’s approach, “ ….we will spend it on other high priority work as developed by our asset investment screening committee”[40] The witness testified that the listing of facility projects of work to be released shows that there is work that is on deck to be reviewed and financially justified. However, the witness confirmed that, while OPG creates a business case including economic benefits before they start any project, not all the projects on the “work to be released” have business cases that form part of this application.[41]

Board staff submits that OPG nuclear rate base for 2011 and 2012 should be reduced as follows:

(in millions)	**2011**	**2012**
Historical Overstatement of rate base (including working capital) p20	$100	$100
Projected under-spending in 2010 Capital p20	$6	$12
Weld Overly at Darlington deferred to 2013 p21	$22	$44
Maintenance Facility at Darlington partial deferral to 2013 P22	N/A	$5
Total	$128	$161

3.3 Hydroelectric Capital Projects

OPG’s 2011 and 2012 Hydroelectric rate base for which it seeks approval, includes approximately $12M for a Visitor Centre at the Saunders Hydroelectric Generating Station. A capital expenditure budget for the Visitor Centre was not included in OPG’s 2008-09 Application. The costs for this project, characterized as “sustaining”, were incurred in 2008, 2009 and 2010. OPG is proposing to treat the $12M as an in-service addition to OPG’s 2010 rate base.

[40] Tr. Vol. 5, p146/ln 28
[41] Ibid., p148/ln 16 to p149/ln 21

Board staff submits that the Board should disallow the $12M that OPG is proposing to include in rate base for this project. In the event the Board disallows the project, Board staff also submits that OPG's OM&A should be reduced by $0.5M, which is the annual budget to operate the Visitor Centre.

OPG has not demonstrated, either in written evidence or testimony that the Visitor Centre is required for the continued operations of the Saunders Generating Plant or is of benefit to ratepayers.

OPG states that the purpose of the Visitor Centre is to provide OPG with a venue to tell the hydroelectric story, to maintain improved public acceptance of the station and its continued operation, to promote OPG's corporate brand and image with respect to all of OPG's generation types, to educate students and the public about the operations and benefits of power generation and promoting water safety.[42]

With respect to "the water safety" component of the Visitor Centre, OPG testified that a room-sized exhibit, out of 13,000 sq. ft of space, was dedicated to the topic.

When asked whether the Visitor Centre will result in increased generating output at the Saunders Generating Plant, OPG testified that, while the Visitor Centre is physically separate from the dam and associated structures, it assisted the ongoing operation of the facility because of the impact it has on OPG's relationship with the City of Cornwall. When pressed for examples of how an "unhappy" City of Cornwall could impact the operation of the generating station, OPG's witness responded that:

> MR. SHEA: They have the ability to lobby with the provincial government. There are a number of interactions that take place on a day-to-day basis that can be easier or more difficult, you know, building permits and different interfaces with the community, just in terms of the day-to-day activities. And those could be either more difficult or less difficult. [43]

In a speech made by Mr. John Murphy, OPG's executive vice-president - Hydroelectric, on February 11, 2008 to the Cornwall Chamber of Commerce[44], Mr. Murphy highlighted

[42] Tr. Vol. 1, p24-45 and ExhD1/Tab1/Sch2 Attachment 1 tab 5.
[43] Tr. Vol. 1, p53
[44] Issue 4.2, ExhL/Tab6/Sch24, part c

that the Visitor Centre would be good for regional tourism and would offset the taxation issues the City of Cornwall had with OPG and the Province.

During cross examination, OPG's witness testified that the Cornwall region made no financial contributions to the project and that OPG's non-regulated Hydroelectric business was not allocated any share of the cost of the project; nor was the witness able to quantify to any degree of accuracy the projected number of visitors expected to visit the Centre.

The OPG witness also confirmed that OPG's proposed revenue requirement includes about $0.5M in OM&A costs related to the operating of the Visitor Centre. These are expenses for a small number of staff for the reception desk (including pension and benefits), maintenance on the heating, ventilation, air-conditioning systems, landscape maintenance, snow-clearing, minor repairs, repair to exhibits and utilities.

In summary, Board staff believes that it is inappropriate for electricity ratepayers to pay for expenditures and investments (i) whose stated purpose includes the promotion of OPG's brand; (ii) whose main focus appears to be regional tourism and an effort to assuage local-provincial issues, (iii) of which the water safety message is a minor element (v) that benefits the non regulated segments of OPG without cost recovery from them, and (vi) that are characterized by OPG as "sustaining" even though they are not directly related to the production of electricity at the Saunders Generating Station. Board staff is not stating that it is inappropriate for OPG to have a Visitor Centre or that the Visitor Centre is not a valuable resource. Staff are only stating that electricity ratepayers should not be funding these activities.

4. DARLINGTON REFURBISHMENT

OPG has decided to proceed with the definition phase of the Darlington Refurbishment Project ("DRP") and to begin associated capitalization of projects costs which result in a number of impacts to the revenue requirement. The definition phase includes the following activities: establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead items and contract establishment. Additionally, all regulatory work will be completed in this phase including the Environmental Assessment, Integrated Safety Review, Global

Assessment, and the Integrated Improvement Plan. OPG states that a release quality project cost and schedule will be prepared at the end of the definition phase, in 2014.

Board staff questions several aspects of the economic analysis that OPG has completed on the DRP. Staff submits that the Board needs to consider certain issues with respect to the project review by the OPA and the review by OPG's internal Depreciation Review Committee in its decision on the treatment of depreciation and asset retirement costs and obligations for this project. Further, staff submits that the Board should deny OPG's request for Construction Work in Progress ("CWIP") for the project. The staff submission on Darlington Refurbishment follows, with the exception of the depreciation and asset retirement costs and obligations, which can be found at section 6 of this submission.

4.1 The Application

OPG is seeking the Board's approval for the following items related to the DRP[45].

a) Test period OM&A costs of $5.9M and $4.5M in 2011 and 2012, respectively, for definition phase work for the DRP;
b) Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from the impacts of the service life extension, for purposes of calculating depreciation, and the change in the nuclear liabilities associated with the DRP;
c) Increase in rate base to reflect the inclusion of CWIP for the DRP; and
d) The recovery of the difference between forecast 2010 non-capital costs associated with the DRP and the costs underlying the payment amounts established in EB-2007-0905.

The 2011-12 revenue requirement impact of the DRP is a sufficiency of $197.1M,[46] despite the fact that there is no revenue from production associated with the DRP until about 2020 and that rate base includes CWIP. Once the DRP was deemed to be in a "definition" phase, OPG submitted that this status, amongst other things, extended the

[45] ExhD2/Tab2/Sch2/p5
[46] ExhD2/Tab2/Sch1/p3 Chart 1 corrected

service life of the Darlington facility, thereby affecting depreciation expenses and the valuation of asset retirement costs and obligations.[47]

OPG confirmed on numerous occasions under cross-examination that it was not seeking the Board's approval to proceed with the project, since there is no regulatory equivalent to a "leave-to-construct" Board review for a nuclear refurbishment project. Accordingly, what the Board can address are the consequent impacts on the proposed payment amounts of the decision to proceed. [48]

Actual to date and forecasted OM&A and Capital costs are as indicated below.

Darlington Refurbishment Costs ($M)

	Actual 2007	Actual 2008	Budget 2008	Variance	Actual 2009	Budget 2009	Variance	Budget 2010	Plan 2011	Plan 2012
OM&A										
Initiation/Definition Phase	$0.4	$7.3	$18.4	($11.1)	$21.7	$22.7	($1.0)	$4.2	$5.0	$2.9
Campus Master Plan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.3	$0.9	$1.6
OM&A -Total	**$0.4**	**$7.3**	**$18.4**	**($11.1)**	**$21.7**	**$22.7**	**($1.0)**	**$5.5**	**$5.9**	**$4.5**
Capital										
Definition Phase	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$44.4	$42.2	$149.2
Campus Master Plan	$0.0	$0.0	$0.0	$0.0	$1.0	$0.0	$1.0	$28.6	$63.0	$106.6
Capital - Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$1.0**	**$0.0**	**$1.0**	**$72.9**	**$105.2**	**$255.8**

Source: Exhibit D2-2-1 p12 chart 2

OPG's 2011 and 2012 rate base includes $125.5M and $306.0M for the project respectively. [49]

OPG estimates that it will take about 36 months to refurbish each unit and the work will be phased as follows:[50]

[47] ExhD2/Tab2/Sc1/p1/ln11-24

[48] Tr. Vol. 13 p. 80 ln 18-23

[49] ExhD2/Tab2/Sch1/Table 1 - The $125.5M is calculated by averaging the gross plant opening balance for 2011(which is the 2010 budget of $72.9) and the gross plant closing balance for 2011(which is the opening balance plus the planned expenditures of $105.2 M). The $306.0M is calculated by averaging the gross plant opening balance for 2012(which is the 2010 closing balance of $178.1) and the gross plant closing balance for 2012(which is the opening balance plus the planned expenditures of $255.8M).

[50] ExhD2/Tab2/Sch1, Attachment 4 p6

Unit	Start of Refurbishment Outage	Finish of Refurbishment Outage	Duration (months)	Overlap on Previous Unit
1st	**October, 2016**	September, 2019	36	
2nd	February, 2018	January, 2021	36	19
3rd	September, 2019	September, 2022	36	16
4th	January, 2021	**January, 2024**	36	19
		Unit Outage Months	144	
		Refurbishment Window	88	

Source ExhD2/Tab2/Sch1/Attachment4/p29

OPG's current projection is that the DRP will cost about $6 to $10 billion, excluding interest and escalation.[51]

With reference to the list on the previous page, staff submits that it is appropriate for OPG to seek recovery of its test period OM&A costs, as noted in item (a) so that OPG can plan its work on the DRP. Staff submits that the recovery of the difference between the forecast 2010 non-capital costs and the costs underlying the current payment amounts, as noted in item (d), is reasonable.

4.2 Certainty of Cost Estimates

OPG has a history of under-estimating the cost of major nuclear projects. Under cross examination by Pollution Probe, OPG confirmed that the original estimate for the Pickering A Unit 1 return to service was $213M and the final cost came in at about $1,016M. In explaining the increase, OPG stated that "… the cost estimate that was put together back in 1999, before work on the unit actually commenced. It was an initial cost estimate."[52] OPG further indicated that in 2004, having completed a cost estimate, the scope of work, the schedule and a re-planned return to service, it went forward to its Board of Directors with a release of funds to execute the work in the amount of $900M.[53]

[51] ExhD2/Tab2/Sch1/p8
[52] Tr. Vol. 6, p178/ln13-16
[53] Ibid., p179/ln 1-5

Board staff questions the conclusion that the costs presented in the current business case in this phase of the project[54] will be materially more reliable than those presented in the Pickering A Unit 1 return to service example. The DRP is still essentially a plan-in-progress. OPG's Board of Directors has only given the go-ahead to go as far as the definition phase of the DRP. As confirmed by OPG, it is only in 2014 that it will revise its feasibility assessment, establish the project scope, cost, and schedule. It is only in 2014 that the OPG Board would approve the execution phase of the project, assuming that the economics of the project remain favourable.[55] [56]

4.3 Business Case

OPG provided a business case, or what it calls an "economic feasibility assessment" ("EFA") based on the feasibility work completed to date and which will be revised in 2014. While noting the uncertainties associated with major nuclear refurbishments and the early stage of scope, schedule, and cost estimate development of the project, OPG stated that it has a very high confidence that the refurbishment of Darlington will result in a Levelized Unit Energy Cost ("LUEC") of less than 8 cents/kWh (2009 dollars).[57] This estimate is based on preliminary planning done to date, a review of current refurbishment experience in the industry, as well as a conservative view of the post-refurbishment operational cost and performance.[58]

The feasibility assessment shows that the LUEC is between 4.7cents/kWh (5% confidence) and 8.0 cents/kWh (100% confidence)[59] and indicates that the project:[60]

- Is one of the most economic generation options available to OPG to maintain a significant footprint in the Ontario Electricity Marketplace;
- Is supported by the Ontario Power Authority as one of the best options to meet the need for base-load generation in the Province of Ontario going forward;

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[54] The Business case is found at Exhibit D2-2-1 attachment A and is titled Economic Feasibility Assessment of Darlington Refurbishment (also known as Preliminary Release Business Case)
[55] Ibid., p10/ln6-10
[56] Tr. Vol. 7, p2/ln26-p3/ln 5
[57] ExhD2/Tab2/Sch1 attachment 4. The Feasibility Assessment (p. 33)shows that the Levelized Unit Energy Cost (LUEC) to be between 4.7cents (5% confidence) and 8.0cents (100% confidence)
[58] ExhD2/Tab2/Sch1/p7/ln17-25
[59] ExhD2/Tab2/Sch1 attachment 4 p33
[60] ExhD2/Tab2/Sch1 attachment 4 p8

- In comparison with Combined Cycle Gas Turbine ("CCGT") options, the DRP exposes OPG to significant risk exposure because of the high capital cost; and
- In comparison with CCGT options, the DRP is less expensive on a life cycle basis and has significantly lower exposure to the risk of fuel costs increases, including the potential imposition of carbon taxes.

Board staff notes that CCGT options are not normally selected for baseload supply and questions the relevance of the comparisons. Staff is concerned with the weight that the EFA should have when considering the proposed regulatory treatment of the DRP.

Board staff also questions the depth of OPA support[61] that OPG has identified. Through GEC's cross examination, OPG agreed that the OPA was expressing an opinion that is prefaced on an assumption about the economics of Darlington which was in turn, based on OPG's own assessment.[62] In other words, the OPA did not conduct a fully independent assessment, and accepted OPG's economic input assumptions as stated to it.

Board staff also questions the comprehensiveness of the LUEC cost analysis and therefore the high level of confidence that OPG places in the LUEC. In cross examination it was determined that:

- Corporate support costs are understated. In cross examination by Board staff, OPG confirmed that the LUEC includes corporate support costs. Board staff pointed out that in 2020, the nuclear allocation of corporate support costs would be entirely borne by Darlington, an amount of $250M versus the current amount of $40M. The OPG witness confirmed that only $40M is reflected in the LUEC;[63]
- In cross examination by GEC, the OPG witness confirmed that the range of inputs for the Monte Carlo analysis was not determined probabilistically but was based on OPG's informed estimate;[64]
- In further cross examination by GEC, the witness confirmed that OPG's analysis does not include the cost of replacement power if replacement of steam generators is required;[65] and

[61] ExhF2/Tab2/Sch3 attachment 2
[62] Tr. Vol. 7, p13/ln 5-8
[63] Tr. Vol. 8, p90-92
[64] Tr. Vol. 7, p19/ln 1-6

- In further cross examination by GEC on sunk costs, the OPG witness confirmed that LUEC is a going-forward approach that does not include sunk costs.[66]

Board staff submits that the business case filed in this proceeding appears to be a preliminary effort and submits that the Board must consider this when setting payment amounts in the 2011-12 test period that incorporate the project's revenue requirement impact as defined by OPG, including the re-setting of depreciation expenses and the valuation of ARCs and AROs The Board may wish to consider whether the case presented by OPG fully meets the tests of "just and reasonable" for prospective rate-making or the prudency test (after-the-fact, historical costs) anticipated by O.Reg. 53/05. Board staff addresses this issue in more detail under the "Decision Framework" section below.

4.4 Capitalization of the Darlington Refurbishment Project

OPG has asserted that the approval of the definition phase of the DRP provided the accounting basis under GAAP for OPG to change its financial accounting and reporting. As a result, two key concurrent accounting treatment changes were triggered effective January 1, 2010:

1. The end date of service lives of the Darlington stations resulting in impacts to the test period depreciation expenses and ARC/ARO consequential changes to certain other expenses (discussed in section 6 of this submission); and
2. Capitalization of all project costs including "OM&A" costs going forward.

OPG discussed its accounting treatment to extend the end date of service lives of the Darlington stations and its capitalization policy in relation to the DRP in Undertaking J10.9.

These accounting changes have enormous ongoing financial impacts on a project that is projected to cost $6-10 billion (or potentially more) over the next 10 to 14 years. For regulatory purposes, OPG has presented these changes as an after the fact non-issue that was already recognized in its accounting treatment. As noted in the application and more recently in the AIC, OPG has stated that it is not seeking Board approval of the decision to refurbish Darlington, but that it is seeking approval of OM&A costs of the

[65] Tr. Vol. 7, p26/ln 10-19
[66] Tr. Vol. 7, p36/ln 9

definition phase, changes in rate base, return on rate base, depreciation expense, tax expense, nuclear liabilities, CWIP in rate base, and recovery of the difference between forecast 2010 non-capital costs associated with the project and the costs underlying the current payment amounts.[67]

OPG essentially wants to receive the benefit of a “non-regulatory” review/approval of the DRP but yet at the same time for the Board to accept the above-noted request without considering the long-term ramifications. This appears to be a dichotomy and disconnect. Staff submits that OPG has asserted that a Board decision should be made premised on the following:

1. No consideration should be given to the long term costs (in the billions of dollars) to be spent on the DRP because it is not in the test period; and
2. The accounting treatment produces the proposed financial impacts so the Board should accept them because OPG has “complied” with GAAP.

Staff is concerned about the long-term implications of the project coupled with OPG’s eventual request for the inclusion of the refurbished station costs in rate base regardless of the amounts, including potential cost overruns. Staff submits there is a key issue as to whether the Board has a regulatory oversight role of the project including the ability to perform a prudence review of refurbished station costs upon project completion. Does the Board have to accept whatever these costs might be in the absence of a prudence review? In addition, if the Board were to approve OPG’s test period requests, would this be considered an implicit Board approval of the entire project? Staff is of the view that parties could assist the Board by providing their positions on these issues.

With respect to the two key concurrent accounting treatment changes that were triggered effective January 1, 2010, OPG has based these accounting changes on two key events:

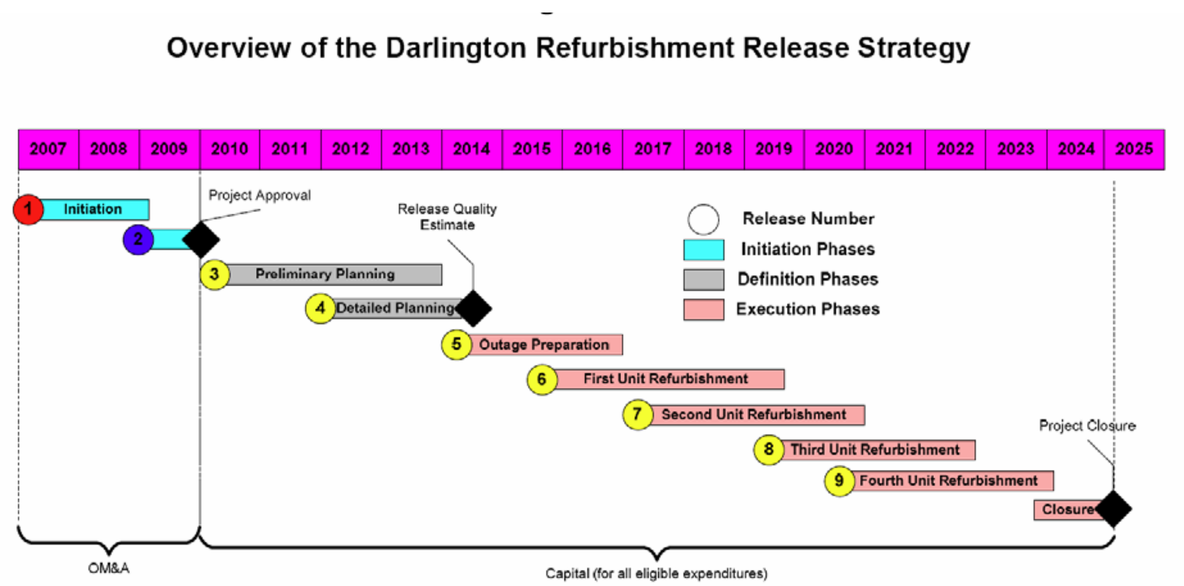
1. The definition phase of the project receiving OPG Board approval in November 2009 (and after receiving Provincial concurrence). OPG prepared an economic feasibility assessment, which among other things, showed the refurbishment

[67] Argument-in-Chief, p40-41

would result in a LUEC of less than 8 cents per kWh (2009 dollars); and

2. The "high confidence" level achieved with the project's definition phase permitted the DRC to recommend and approve station end of service life from 2019 to 2051 in the 2009 DRC report of January 2010.

The definition phase includes the completion of two milestones, as illustrated in the figure[68] below, the preliminary planning that starts in 2010 and ends in 2012 and the detailed planning that starts in 2013 and ends in 2014. The first outage to commence refurbishment work on the first unit does not start until 2016 and the last unit is scheduled for competition in 2024. OPG stated that during the definition phase of the project it would confirm the project scope, cost and baseline schedule. Specifically, in 2014, OPG will revise its feasibility assessment, establish the project scope, cost, and schedule and prepare a recommendation to the OPG Board to proceed to the execution phase of the project, assuming that the economics of the project remain favorable.



Key information on the project detailed planning, economics and cost approval of the OPG Board does not occur until the end of 2014 with the release quality estimate. From an accounting perspective, it is questionable whether the approval to start the definition stage of the project, which includes further assessments on very complex CANDU technology refurbishments, meets the test to capitalized project costs.

68 ExhD2/Tab2/Sch1/p10

Furthermore, there is uncertainty and risk if the Pickering A Return to Service project is used as a reference. As noted in the above DRP section, there were significant time delays and cost overruns versus the initial estimate.

The Canadian Institute of Charted Accountants (CICA) Handbook does not provide prescriptive accounting guidance in this area, namely, identifying whether a project at the “definition phase” meets accounting criteria for capitalization, and if so, when it should start. The CICA Handbook, Section 3061, Property, Plant and Equipment (PP&E), provides general guidance on types of costs that could be capitalized but not when to start, as follows:

Paragraph 5 regarding definitions states the following:

> **Cost** is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use. Cost includes any asset retirement cost accounted for in accordance with ASSET RETIREMENT OBLIGATIONS, Section 3110.

Paragraphs 20 and 23 respectively, regarding acquisition, construction or development over time states the following:

> The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.
>
> The cost of an item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity such as interest costs when the enterprise's accounting policy is to capitalize interest costs. For an item of rate-regulated property, plant and equipment, the cost includes the directly attributable allowance for funds used during construction allowed by the regulator.

Paragraph 27 regarding betterments states the following:

> A redevelopment project that adds significant economic value to rental real estate is treated as a betterment. When a building is removed for the purpose of redevelopment of rental real estate, the net carrying amount of the building is included in the cost of the redeveloped property, as long as the net amount considered recoverable from the redevelopment project exceeds its cost.

However, CICA Handbook, Section 3064, Goodwill and Intangible Assets, while not specifically related to PP&E discussed above, provides accounting guidance on capitalization and when it should occur in relation to intangible assets under research and development. This analogy could be used to assess whether the start of the definition phase is consistent with the general framework of this accounting guidance. The following is an excerpt of Section 3064, paragraphs 37 to 40:

Research phase

> .37 No intangible asset arising from research (or from the research phase of an internal project) should be recognized. Expenditure on research (or on the research phase of an internal project) should be recognized as an expense when it is incurred. [OCT. 2008]
>
> .38 In the research phase of an internal project, an entity cannot demonstrate that an intangible asset exists that will generate probable future economic benefits. Therefore, this expenditure is recognized as an expense when it is incurred.
>
> .39 Examples of research activities are:
>
> (a) activities aimed at obtaining new knowledge;
>
> (b) the search for, evaluation and final selection of, applications of research findings or other knowledge;
>
> (c) the search for alternatives for materials, devices, products, processes, systems or services; and
>
> (d) the formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

Development phase

.40 An intangible asset arising from development (or from the development phase of an internal project) should be recognized if, and only if, an entity can demonstrate all of the following:

(a) the technical feasibility of completing the intangible asset so that it will be available for use or sale.
(b) its intention to complete the intangible asset and use or sell it.
(c) its ability to use or sell the intangible asset.
(d) how the intangible asset will generate probable future economic benefits. Among other things, the entity can demonstrate the existence of a market for the output of the intangible asset or the intangible asset itself or, if it is to be used internally, the usefulness of the intangible asset.
(e) the availability of adequate technical, financial and other resources to complete the development and to use or sell the intangible asset.
(f) its ability to measure reliably the expenditure attributable to the intangible asset during its development. [OCT. 2008] [emphasis added]

In view of the accounting guidance on the research and development phases noted above, OPG's preliminary planning of the definition phase does not appear to meet the requirements in the "development" phase in order to capitalize costs. Staff observes that OPG has not fully demonstrated that 2010 was the proper time to start capitalization of costs given the project's early stage and its associated uncertainties. In the absence of OPG providing clear evidence, staff submits that the detailed planning phase in the 2013 to 2014 timeframe provides a more persuasive and reasonable basis to capitalize costs as this phase could provide, among other things, a more reliable economic assessment of the project including the quantum of the expenditures and whether the high confidence assessed in 2009 was sustained.

4.5 Construction Work in Progress (CWIP) Treatment

On January 15, 2010, the Board Report, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, EB-2009-0152, was issued.

OPG is proposing to include the DRP CWIP in rate base since such treatment:

> "…meets the criteria for qualifying investments specified by the OEB in its Report [January 15, 2010 Board Report titled *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*]. The project spans a number of years, has material costs associated with it (i.e., it is capital intensive) and it will form a significant portion of OPG's rate base once placed into service. Moreover, the risks of the project are similar to those noted by the OEB for green energy projects, which include risks related to project delays, public controversy, and the recovery of cost since it meets the criteria for qualifying investments specified by the OEB in its Report". [69]

Board staff submits that the DRP proposal does not in the first instance fall within the scope of the Report. On this basis Board staff believes that the Report should not be used as a primary justification for the Board to accept OPG's proposed treatment. The Report pertained to investment in infrastructure by electricity transmitters and distributors in the context of the *Green Energy and Green Economy Act, 2009.*

Under cross examination, OPG agreed that nuclear generation was not mentioned in the Report and related Board correspondence[70] and that the DRP is not a *Green Energy and Green Economy Act* infrastructure project.[71] OPG's witness also confirmed that OPG had filed comments on Board staff's predecessor paper and, while noting his lack of recollection of the submission, agreed that it would not have been inconsistent for OPG to have specifically requested that the report apply equally for nuclear generation. Board staff notes that despite this explicit request from OPG, the Board's Report did not specifically include nuclear generation projects as eligible for alternative cost recovery mechanisms.

4.5.1 Rate Shock and Credit Risk

OPG states that a reason for including CWIP in rate base is that this treatment smoothes rates, thereby avoiding rate shock, and reduces borrowing costs.[72] OPG provided two graphs illustrating the smoothing affect. An excerpt from Undertaking

[69] ExhD2/Tab 2/Sch 2/p3/ln6-13
[70] Tr. Vol. 13, p174-176
[71] Tr. Vol, 13, p76/ ln 2-5
[72] ExhD2/Tab2/Sch2/p5-9

J14.2, which shows and illustrates the smoothing impact in tabular form by comparing revenue requirement with and without CWIP treatment, is re-produced below.

$M	$6B Project Example		$10B Project Example	
	With CWIP	Without CWIP	With CWIP	Without CWIP
2018	187		297	
2019	257		418	
2020	415	357	679	561
2021	530	526	877	851

Board staff observes that with the exception of the transition from 2019 to 2020, rate shock is not evident in other years and the comparative revenue requirement impact is largely similar going forward. The Board panel, referencing Exhibit K13.4, made a similar observation during the oral hearing.[73]

OPG noted in its evidence that:

> OPG has not yet determined the project financing specifics associated with the Darlington Refurbishment project. Regardless of those specifics, the inclusion of CWIP in rate base will serve to reduce borrowing costs for the utility. An entity's ability to access financing will be evaluated based on the risks that they face, including the degree of financial leverage and its standing on a number of standard financial risk metrics (e.g., interest coverage ratios).[74]

OPG's witness when questioned about the impact on credit risk confirmed that, "If we don't get it [CWIP] and we'd proceed with this project, as is our plan, we expect some impact on our credit metrics."[75] However, when queried as to the magnitude of the impact on credit risk, OPG's witness could only provide a directional answer, " things will be much worse. We don't know how much worse. And, again that remains to be seen."[76] Board staff submits that absent some tested quantification of the credit risk, that will ensue if the CWIP proposal is disallowed, the Board has little reliable and substantive evidence upon which to assess the benefit claimed by OPG. Further, Board

[73] Tr. Vol. 14, p11
[74] ExhD2/Tab2/Sch2/p9/ln 6-11
[75] Tr. Vol. 13, p49
[76] Tr. Vol. 13, p52/ln16-18

staff notes that OPG plans to proceed with the DRP with or without CWIP, and does not appear to be especially concerned with impacts on borrowing costs.

Staff notes that including CWIP in rate base can be an effective tool in addressing issues such as rate shock and credit risk, if justified. However, for the reasons noted above, Board staff does not support the inclusion of CWIP in rate base in this instance.

4.5.2 Return on CWIP

In the event the Board finds that CWIP should be included in rate base, Board staff submits that OPG's return should be limited to only interest costs as opposed to OPG's total cost of capital (which includes ROE). Board staff refers to a recent Hydro One decision as a precedent in this regard. [77]

4.6 Decision Framework

Board staff is concerned with the implications that may arise with the decision framework OPG is advocating. Specifically, Board staff is concerned with how OPG will interpret a Board decision that includes the recovery of DRP related costs, including CWIP, in 2011-12 rates as proposed by OPG. For example, in cross examination OPG was asked if it would view the approval of the CWIP proposal as an approval of the prudency of the DRP. OPG's witness, Mr. Barrett, responded: "Certainly in respect of the capital that we are proposing to spend in the test period, I don't see how you could not have that linkage."[78]

In addition, when questioned by SEC earlier that day, the OPG witness stated that "….Now, presumably if the Board had a view that it was not reasonable to proceed with the project, then they would not approve the things that flow from that. So they would essentially reverse those things if they took that view. [79]

Therefore, from OPG's perspective, by approving the proposed test period revenue requirement impacts relating to the DRP, the Board would also be finding that the DRP is not unreasonable or in other words "reasonable".

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[77] Decision with Reasons, EB-2006-0501, August 16, 2007, p64
[78] Tr. Vol. 13, p185
[79] Tr. Vol. 13, p83/ln20-22

Although OPG has stated it is not seeking explicit Board approval for the DRP, it appears that OPG's view is that approval of the CWIP proposal would amount to an implicit finding of prudency for the DRP itself. Board staff submits that the Board take into consideration OPG's stated interpretation and explicitly address this issue in its decision.

Board staff is not certain that the parties to this proceeding clearly understood OPG's position in this regard at the outset of the hearing. The evidence presented in support of the DRP is somewhat less than what one would expect if the Board is being asked to make a finding of prudence, whether explicit or implicit. To assist the Board, Board staff invites parties to address in their argument their understanding and expectation of what Board approval of OPG's CWIP proposal would signify regarding the prudency of the DRP itself.

Board staff notes that the revenue requirement impact of the DRP as proposed by OPG is a credit of $200 M; or put another way, were the Board were to disallow the DRP costs and service life adjustments and other changes, OPG's test period revenue requirement would increase by about $200M.[80]

With respect to the "just and reasonable" test to be met in considering the revenue requirement impact of the DRP, Board staff is of the view that the current business case provides minimal, but sufficient justification, to proceed with the revenue requirement implications of the plan, except for the CWIP component, in so far as it impacts the test period payment amounts. However, Board staff views the business case as deficient, for the purposes of the Board approving the future (i.e. post 2012) cost implications of the DRP in its entirety. In the event the Board accepts the DRP impact on 2011-12 payment amounts, Board staff believes that the Board should explicitly state that its decision in no way should be interpreted as signaling approval of the DRP to completion and that the prudency of expenditures and accounting changes, undertaken by OPG during the test period, will be subject to a prudency review in the next proceeding. The Board should also note that the outcome of the prudency review could include a disallowance of incurred costs and/or the unwinding of the service life assumptions which could cause rates to increase, all else being equal, in the next test period.

[80] Exhibit K16.4

5. OPERATING COSTS

Board staff provides submissions on the following operating cost subjects in this section: nuclear benchmarking, nuclear base OM&A, nuclear fuel, Pickering B continued operations, regulatory affairs, nuclear insurance, depreciation and HST. Staff submits that the Board should reduce OPG's operating costs by $127.8M in the test period.

5.1 Nuclear Benchmarking

5.1.1 Background

The Board directed OPG to undertake extensive benchmarking in the decision from the previous proceeding:[81]

> … the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. …
>
> Navigant completed Phase I of its study in 2006. Phase 2 as described at page 9 of the Navigant Report was to set OPG's strategy and performance targets. Specifically, Phase 2 was to address the question "what level of cost and operational performance improvement is justified". Phase 3 was to develop and execute an implementation plan. Specifically, Phase 3 was to address the questions "what specific initiatives and actions are needed to achieve identified performance improvement targets. The questions Navigant suggested should be addressed in the second and third phases of the study are important questions. They are directly responsive to paragraph A.3 of the MOA.
>
> The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report.

[81] Decision with Reasons, EB-2007-0905, p30-31

In response to that directive, OPG retained ScottMadden Inc. (“ScottMadden”) who produced two reports. The Phase 1 report presents a comparison of OPG Nuclear’s financial and non-financial performance to that of nuclear industry peer groups in both the U.S. and Canada. A total of 19 performance indicators were chosen for comparison. The objective of this study was to clarify and confirm performance gaps and to identify potential cost and performance improvement areas for inclusion in OPG’s 2010-2014 Nuclear Business Plan. The Phase 2 report built on the comparative analysis from Phase 1 to: (a) identify where cost and operational improvements are warranted; and (b) to formulate targets and action plans for achieving those improvements.

5.1.2 Phase 1 Report

The Phase 1 report identified three key metrics (of the 19 benchmarked) and OPG’s rank vis-à-vis the comparators, as illustrated in the following table:

Key Metric	Description	OPG Rank
NPI - WANO Nuclear Performance Index	Provides a comprehensive overview of a nuclear operator’s overall operating performance. OPG’s low unit capability factor (UCF) and high forced loss rate (FLR) are the primary contributors to its relative ranking.	17th out of 20
TGC – Total Generating Cost per MWh	Highest indicator of an operator’s overall financial performance. This metric is the sum of non-fuel operating costs per MWh, fuel costs per MWh, and capital costs per MWh, and represents the “all in” cost of producing each MWh of power.	18th out of 20
UCF – Unit Capability Factor	The ratio of available energy generation to the reference energy generation (i.e., energy that could be produced if the unit were operating continuously at full power under normal conditions) over a given time period.	16th out of 16

Source ExhF5/Tab1/Sch1/p141-145

5.1.3 CANDU vs U.S. Reactors: Advantages as well as Disadvantages

Board staff notes that OPG is inclined to focus on the disadvantages of CANDU reactors that are outside of OPG's control when making comparisons with US pressurized water reactors ("PWR") and boiling water reactors ("BWR"). In interrogatory #53, Board staff asked OPG why the targeted performance improvement by 2014 with respect to TGC for the Pickering stations is still below the industry median. OPG explained that the poor asset condition is reflected in higher outage days and forced loss rates ("FLR") compared to the industry median. The response also attributed Pickering A's failure to achieve the median to issues that remain associated with the 7-year shutdown of the units prior to their return to service in 2003 and 2005. The response concluded in noting that poor asset condition is only one factor and discussed structural factors that drive higher costs including the smaller size of the reactor units compared to industry median and the complexity of CANDU technology compared to the benchmarked reactors which are predominantly PWR and BWR.

Staff notes that, in terms of Pickering A, by 2014, a decade will have elapsed since the units were returned to service, and that the Board previously approved a temporary increase in OPG's revenue requirement to reduce the backlogs (corrective and elective) to improve the material condition.

Staff also notes that ScottMadden discusses advantages of the CANDU plants. The report notes that CANDUs experience lower fuel costs and have a significant advantage over PWRs and BWRs because CANDUs do not require enriched uranium. The report notes that, "CANDU is the most efficient of all reactors in using uranium, requiring about 15% less uranium than a pressurized water reactor".[82] In cross examination, Board staff also identified that the Phase 1 report noted corporate costs and potential controllable costs were also factors contributing to OPG's higher TGC and asked OPG the following: "So there are factors, at least identified by ScottMadden, that arguably are within your control. Is that fair?" OPG agreed.[83] In cross examination by SEC, OPG also identified another advantage for CANDUs in noting "the on-power fuelling enables us to avoid outages simply for refuelling the core."[84]

[82] ExhF5/Tab1/Sch1/p123,135
[83] Tr. Vol. 3, p37
[84] Tr. Vol. 3, p127

In cross examination by Board staff, Mr. Sequeira (of ScottMadden) was asked about the extent to which the advantages of the CANDU reactors offset some of the technical disadvantages. Mr. Sequeira's response was "often we are asked to adjust the benchmarking metrics to make them an absolute apples-to-apples comparison…It probably is impossible to absolutely quantify the contributions of every piece of technology. Every one of the plants, whether they're PWR or CANDU, is almost a unique design. No two are absolutely the same…When we try to adjust the benchmarks over time, it gets to the point that nobody believes the benchmarks anymore. I mean, it is like, [w]ell, that's just a fabricated number that OPG wants to look at to compare themselves."[85]

Board staff is of the view that, given CANDU reactors have advantages, as well as disadvantages, and there is no evidence in this case that the disadvantages exceed the advantages, the CANDU technology should not be a significant consideration in assessing OPG's relative performance to U.S. reactors.

Board staff is of the view that the important consideration in regard to benchmarking against the comparators in the Phase 1 report is OPG's relative ranking and how that ranking changes over time, particularly in respect to the three key metrics discussed above.

5.1.4 OPG Targets - "Continuous Improvement"?

Comparisons between OPG's nuclear plants and comparators in the U.S. and other CANDU plant are informative; however there are difficulties in making absolute apples-to-apples comparisons as discussed above and also due to factors such as the differences in age as reflected by the relative performance of Darlington vis-à-vis Pickering. Board staff therefore believes that it is useful to supplement the benchmarking by assessing the OPG targets for each plant against its own historical performance in order to assist the Board in its decision-making.

Board staff also believes that, within the context of OPG's targets, it is important to consider OPG's Memorandum of Agreement ("MOA") with its shareholder[86] which states:

[85] Ibid., p41
[86] ExhA1/Tab4/Sch3/p4

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

In interrogatory #30, SEC noted that Darlington's two year Forced Loss Rate ("FLR") average was 0.93% and queried why the FLR target is much higher at 1.5% for 2011 and 2012. OPG's responded that 1.5% is based on a five year historical average of 1.6%. Staff noted that the five year average used by OPG includes an outlier of 3.2% in 2006. In cross examination by Board staff[87], OPG agreed that the FLR target would be 1.1% if the outlier was not considered. OPG identified that the incremental revenue impact for 2011 and 2012 would be approximately $7M per year based on a 0.12 TWh per year increase in generation resulting from an FLR of 1.1% versus the 1.5% FLR target.[88] Board staff submits that an FLR exceeding 1.1% does not represent "continuous improvement" and that the Board may wish to consider removing $14M from the revenue requirement.

SEC identified in interrogatory #29 that the TGC target for Darlington is 8.4% and 11.3% higher than the 2008 actual TGC. OPG explained that the increases are due to an assumed 4% inflation rate each year. In response to cross examination by Board staff, OPG confirmed that the 4% inflation rate was based on a historical average. Staff asked OPG whether performing at an industry average was consistent with continuous improvement referred to in the Memorandum of Agreement with the shareholder. OPG responded, "We will seek to set challenging but achievable goals".[89] Board staff submits that a TGC target based on an industry historical average represents neither continuous improvement nor a challenging goal, particularly given OPG's ranking in the industry of 16th out of 16 in terms of TGC as noted above.

The 2008 non-fuel benchmark for Darlington, based on a three year average, is $25.10/MWh. SEC interrogatory #26 questioned Darlington's targets for 2010-2012 as they are all higher than the 2008 benchmark. OPG's response identified if they were

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[87] Tr. Vol. 3, p45
[88] Undertaking J3.2
[89] Tr. Vol. 3, p47-48

able to maintain $25.10/MWh, the OM&A reduction would be $40.89M (2011) and $45.62M (2012). This submission discusses OPG's claim of $260M of work driven cost savings since 2008 in section 5.2.1 of this submission. Board staff finds it difficult to reconcile the claimed $260M in cost savings with these increases in OPG's targets for non-fuel operating costs. Board staff submits that OPG either did not actually achieve $260M in net cost savings or OPG should be able to at least maintain the three year average of $25.10/MWh if OPG did achieve those cost savings.

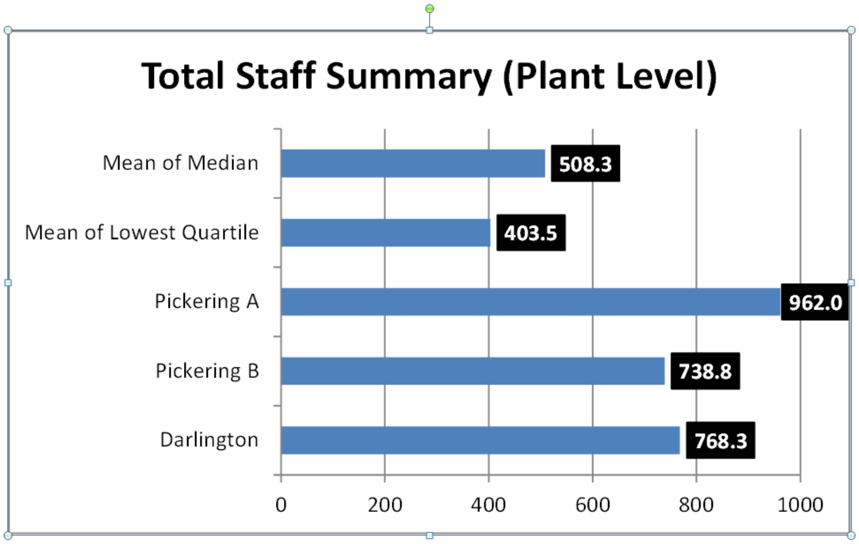
5.1.5 OPG Staff Level Benchmarking

The Phase 2 report at p26 notes, "The results of both the EUCG and the Bruce Power functional comparison showed that overall OPGN staff levels per unit exceed both the industry median and Bruce Power levels… For the most part, however, OPGN staff levels are generally higher than the comparison panels. It should be noted that, however, that staffing levels can be influenced by a company's approach to staffing project-based outage functions. Certain North American operators rely extensively on third-party contractors for such services, whereas others, including OPGN, largely rely on in-house resources." In cross examination, Board staff asked Mr. Sequeira "based on your what I assume to be very extensive experience in benchmarking utilities, can you tell us generally if it is cheaper to -- or more efficient… to hire third-party contractors to do these types of services, or is it better to use in-house folks, from a cost perspective?" Mr. Sequeira's response was "I would think that the majority of companies who have decided, for a particular function, to employ outside contractors have done so for cost reasons, cost-reduction reasons." Staff asked "Does that mean it is generally cheaper to do it that way?" Mr. Sequeira noted "Yes, I believe so."[90] Board staff suggests that OPG should consider greater use of third-party contractors for functions such as project-based outages in order to reduce costs on a go forward basis.

Board staff also entered into evidence the chart below which shows total staffing at the plant level.[91] The chart is based on EUCG data taken directly from Appendix G (Staffing Analysis) of the Phase 2 report and shows OPG staffing levels at all three plants to be much higher than the "Mean of Median" and the "Mean of Lowest Quartile" of the EUCG

[90] Tr. Vol. 3, p15-16
[91] ExhK3.1, p9

comparators. In cross examination, Mr. Sequeira confirmed that the comparisons were normalized for the size of the plants and the number of units.[92] **(Tr. Vol. 3, p17)**



Source: F5-S1-T2, page 59 of 64, ScottMadden, Phase 2 Final Report, Appendix G – Staffing Benchmark Analysis – EUCG Data (Plant Level), "This appendix presents plant-level staffing comparisons prepared using EUCG data". The figures in the chart above are taken from the line referenced as "Sub-Total Total Staff" on p. 59 which excludes security as figures are not included in the report for confidentiality reasons.

The Board's EB-2007-0905 decision discussed the Navigant staffing benchmarking report which identified OPG's 2006 staffing levels to be 12% higher than the benchmark. Board staff asked if any analysis had been done on a specific percentage by which OPG would now be above the industry median. Mr. Sequeira noted they did not do such an analysis.[93] OPG has committed to update the benchmarking report on an annual basis and has already filed its most recent update of the Phase 1 report in response to undertaking J3.5. Board staff submits that an updated benchmarking report should be filed as part of OPG's next application and it should be supplemented to include an update to the staffing analysis undertaken by ScottMadden in Appendix G of the Phase 2 report.

5.1.6 Radiation Protection Function Pilot

ScottMadden conducted a top-down staffing analysis pilot on one segment of OPG's organization -- Radiation Protection (RP) Function. ScottMadden found it to be over-

[92] Tr. Vol. 3, p17
[93] Ibid., p16

staffed by 48 FTEs (or 28%) and recommended in the Phase 2 Report that OPG should consider reassigning 35 FTEs and eliminating 13 FTEs.[94]

In Board staff interrogatory #58, OPG was asked to identify if the above recommendation was implemented and how OPG planned to build on this pilot in terms of other segments of the organization. OPG identified that they did reassign 35 FTEs but only eliminated one position of the 13 recommended. OPG explained that implementation of the additional proposed reductions in the RP function was not part of the 2010 – 2014 business plan. In cross examination, staff asked OPG "You just stated that you are looking to make savings, you have a goal of continuous improvement, you have a firm recommendation from your consultant that you can eliminate 13 positions here. This would have seemed to me to be an obvious place to take action. To the extent you haven't already, can you explain why more positions haven't been eliminated here?" OPG's response was "Well, we are taking action … certainly this is, you know, work in progress. There have been some significant challenges in this organization in the last year. And so I would say that we need to manage this area, and that is what we are doing. So we are looking at all of the options, and certainly looking very carefully at this. But in the end, it is our organization and we need to do what is right."[95]

Staff requested that OPG undertake to provide the compensation costs for the 13 positions. In undertaking J3.1, OPG estimated that eliminating all of the positions would reduce costs by approximately $2.2M per year. Staff submits that ratepayers should not bear the cost of $4.4M over the test period associated with OPG's choice to retain staff that its expert consultant has identified are not necessary.

5.2 Nuclear Base OM&A

OPG is requesting approval of test period Base OM&A costs of $1,192.3M and $1,219.8M in 2011 and 2012, respectively, in relation to its nuclear operations.[96] While the total nuclear OM&A budget also includes Project OM&A and Outage OM&A, Base OM&A is the predominant funding source for the nuclear business. OPG's cost

[94] ExhF5/Tab1/Sch2/p26
[95] Tr. Vol. 3, p34
[96] ExhF2/Tab2/Sch1/p1

containment and performance improvement Initiatives are also focused on Base OM&A.[97]

5.2.1 Assessment of Cost Savings of $260M

OPG states in the application, "OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically, 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with cumulative work-driven cost savings of $260M for the 2010 - 2012 period; 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular staff FTEs ("full time equivalents") are reduced by 559".[98] The application also notes that these reductions are due to the seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan and other cost control measures explained in ExhF2/Tab1/Sch1.[99]

The amount of quantitative information in the application supporting the claim of "work-driven cost savings of $260M" is quite limited. Board staff Interrogatory #45 requested that OPG provide the estimated FTE and cost savings associated with each new initiative as well as each additional new cost saving measure OPG refers to in the application. In response, OPG provided "Table 1: OM&A Savings Associated with Fleet-Wide Initiatives ($k)". The savings in the table totaled $40.3M over the test period, which is only 15% of the $260M in "work-driven cost savings". In response to a Board Staff Technical Conference Question (#41), OPG identified that the completion of certain initiatives accounts for $30M including the: (1) Temporary increase in OM&A costs/FTEs approved by the Board to address the backlog issue (in the previous application); and (2) Discontinuation of Service Agreements with Bruce Power. However, Board staff notes that "work-driven" savings implies cost reductions due to increased efficiencies and does not accept that the simple completion of these initiatives constitutes "work-driven" savings.

In cross examination by Board staff about the $260M in "work-driven cost savings", OPG referred to a chart in the application[100] which shows $131M in savings relative to 2008 and two adjustments (cost increases) accounting for the other $129M associated

[97] ExhF2/Tab2/Sch1/p18
[98] ExhF2/Tab2/Sch1/p1
[99] ExhA1/Tab3/Sch1/p4
[100] ExhF2/Tab2/Sch1/p16, Chart 2

with “Escalation/53rd week in Base OM&A” and “Pickering B Continued Operations”. Staff questioned OPG, “it seems that you have made certain adjustments that are favourable to you, to the extent that they bulk up the 131 million to 260 million. But surely there would be other offsets going the other way …I am wondering why those …. weren't included in your estimate of 260 million.” OPG did not explain why adjustments were only made in a favourable direction.[101]

Staff then asked about the $131M in savings in the chart discussed above. OPG confirmed that the $40M associated with the fleet-wide initiatives contributed to the $131M and staff requested a similar chart as was provided in Board staff Interrogatory #45 (for the fleet-wide initiatives) that would provide a similar breakdown of the $131M. OPG did identify the local and divisional measures, including contracted services, outsourcing, overtime, organizational consolidations during cross examination.[102] However, Undertaking J4.3 did not provide a breakdown of the $131M as was requested.

In cross examination by staff, OPG also confirmed that they had under-spent in both of the previous test years by $67M ($10.3M in 2008 and $56.7M in 2009) as identified in ExhF2/Tab2/Sch2 (Tables 1a and 1b) of the application.[103] Staff subsequently asked OPG, “I am assuming that OPG pocketed the $67 million, but perhaps it was allocated to other O&M … Do you happen to know what happened to that money?” OPG’s response was “I don't know”.[104]

5.2.2 Assessment of FTE Reductions

In staff Interrogatory #45, staff questioned the claimed FTE reductions of 689 regular staff and 559 non-regular staff from 2008 because reductions are based on subtraction of 2008 headcount from 2012 FTEs. Staff requested that the headcount numbers be converted to FTEs for an apples-to-apples comparison. Staff notes that it may be coincidental but the largest decrease occurs between 2009 and 2010, when the method of counting OPG staff changes from headcount to FTEs. In cross examination by staff, OPG acknowledged headcount and FTEs counted different things and were not directly

[101] Tr. Vol. 4, p66-69
[102] Tr. Vol. 4, p71-72
[103] Ibid., p75-76
[104] Ibid., p.78

comparable.[105] OPG agreed to provide FTE and headcount numbers for 2010-2012, Undertaking J4.4, and for 2007-2009, Undertaking J9.1, and subsequently filed a consolidated response.

Staff has a number of concerns in relation to the undertaking response. First, it only provided figures for Regular staff and Board staff expected a more significant differential between headcount and FTEs to be in relation to Non-regular staff. Undertaking request J9.1 was not limited to Regular staff, as the cross examination preceding the request was in relation to Total Staff FTEs. Second, OPG notes in the undertaking response that 2007-2009 FTEs are a proxy value and that “this is a relatively **imprecise** measure of historic FTEs”. (emphasis added). Board staff questions why the differential between headcount and FTEs will only be 3 in 2012 as the OPG witness stated that a comparison between headcount and FTEs is “comparing apples to oranges.”[106] Regardless of it being an imprecise measure, staff notes the reduction in Regular staff FTEs of 443 in the undertaking response is lower relative to the reduction of 689 noted in the application.

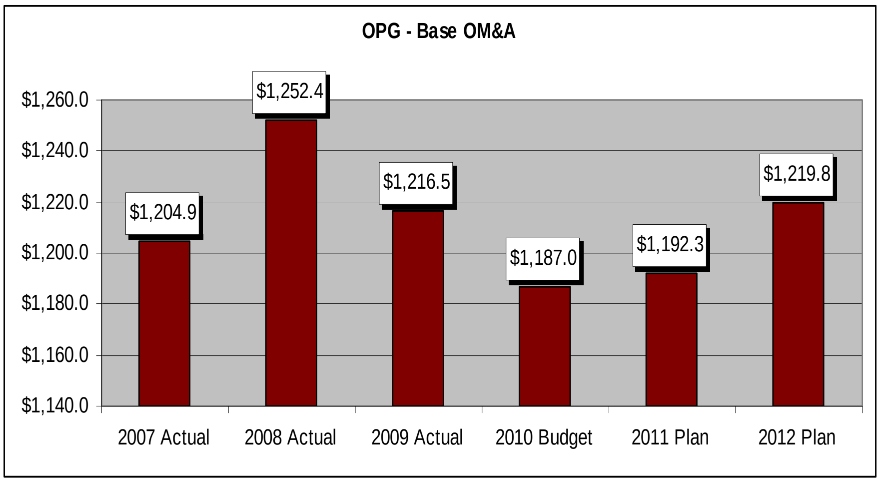
OPG confirmed, in response to Board staff Technical Conference Question #41, that 185 of the cumulative reduction of 265 in FTEs from 2009 to 2012, was solely attributable to “Discontinuing Service Agreements with Bruce Power”. Staff notes that a significant portion of the FTE reduction was simply due to the discontinuation of a service agreement and was not due to increased efficiencies and “work-driven” savings.

Based on the above, Board staff acknowledges that OPG has achieved some material FTE reductions in its Nuclear group and that this is an improvement relative to trends in prior years. At the same time, staff submits that the number of “work-driven” FTE reductions is much lower than those claimed in the application. Staff also submits that it is imperative that OPG begin tracking FTEs so that the OPG staff numbers for all years in the next application are provided on the same basis and so that the Board can make accurate and fully informed decisions.

[105] Ibid, p. 80
[106] Tr. Vol. 8, p213

5.2.3 Assessment of 2008 as Comparison Year

Staff submitted into evidence a chart showing the trend in Base OM&A from 2007 – 2012 as shown below.[107] In cross examination by Board staff, OPG confirmed that the number of OPG nuclear staff and nuclear Base OM&A costs both peaked in 2008 and that 2010 is OPG's low watermark for Base OM&A spending, which was also the year that OPG did not submit an application to have its payment amounts set.[108]



Staff also submitted into evidence an SEC interrogatory from the last OPG payment amounts case in which OPG explained spending and the filling of staff vacancies that had been deferred from 2007 to 2008.[109] It also states in OPG's application that staff levels in 2008 "reflect the filling of a large number of vacancies that existed in 2007".[110]

Given all of the above, staff questioned OPG regarding whether 2008 is an appropriate base year against which OPG should make the comparisons and also, given the similar trend as from 2007 to 2008, staff asked OPG "we discussed the low-water mark of 2010 for your base OM&A spending, and then it starts to ramp up again in the test year. Did

[107] ExhK4.2, p15
[108] Tr. Vol.4, p87-88
[109] ExhK4.2, p16
[110] ExhF2/Tab2/Sch1/p17/ln17-19

you defer any spending from 2010 to either of the test years?" OPG noted that they were not aware of any major spending being deferred.[111]

Staff observes that comparisons to any year other than 2008 would be unfavourable to OPG. Further, staff notes that OPG increased Base OM&A spending in 2008 (from 2007). In terms of Base OM&A, as shown in the chart above:

- From 2007 to 2012, there is an increase of $14.9M.
- From 2010 to 2012, there is an increase of $32.8M.

5.2.4 Assessment Summary

Staff submits that OPG has not achieved "work-driven cost savings" of $260M as stated in the application. The only evidence in this case is that OPG is targeting $40M in "work-driven cost savings" associated with the fleet-wide initiatives. Staff also submits that a comparison to 2008 is misleading given all of the costs and vacancies that were deferred from 2007 to 2008 which contributed to the significant Base OM&A increase of $47.5M from 2007 to 2008.

Given the significant reduction in Base OM&A from 2009 to 2010 and ramping up again of spending in 2011 and 2012, Board staff is also concerned that costs may have been deferred from 2010 to the test years (in a similar manner as the deferrals from 2007 to the previous test years). The chart above appears to show a concerning trend in this respect.

It appears to staff that OPG's inclusion of the claim in the application of $260M in "work-driven cost savings" is to make the case that no further reductions are necessary or should be imposed by the Board. Evidence of this appears in OPG's response to the Minister's letter directing OPG (and Hydro One) to review their application in order to reduce consumer bill impacts. OPG ultimately only looked at one option, the extending of variance/deferral account recovery.[112] Staff notes that the extension actually results in a $240M cost increase to consumers due to borrowing requirements.[113] In cross examination by CME, OPG also noted that the decision to extend recovery was made in advance of receiving the Minister's letter and that there was no reassessment of the

[111] Tr. Vol. 4, p88-92
[112] Undertaking JT1.10
[113] Undertaking JT1.12

contents of the application to ascertain if bill impacts could be reduced after the Minister's letter was received.[114] OPG stated the reason for that was "we had made all of the cuts and reductions that it was reasonable and prudent to make."[115]

5.3 Nuclear Fuel Costs and Nuclear Fuel Cost Variance Account

5.3.1 OPG Strategy and Price-Cost "Disconnect"

OPG's test period forecast for OM&A associated with nuclear fuel costs is $235.6M (2011) and $261.7M (2012)[116]. From 2007 to 2012, OPG's fuel costs show an increase of $148.7M, from $113M to $261.7M. In other words, the costs have more than doubled. This includes an increase of $89.1M or about 52% from 2009 (the final test year of OPG's last application).

Both the spot market and long term uranium prices have been steadily declining over the past 2 years from over US$90/pound to about $40 and $60/pound, respectively, and have also been relatively stable. OPG's application notes the uranium market (spot and term) prices has "leveled off after spiking in 2007".[117] Over the same period – 2008 to 2010 – OPG's uranium costs have increased by about 35% (or $45.2M) and are forecast to increase a further 32% (or $55.7M) by 2012. The application notes this "disconnect" between declining market prices and rising OPG costs is due to various factors including the timing of OPG's negotiation of uranium concentrate contracts.

OPG's response to Board staff Interrogatory #65 notes that its procurement strategy includes "regularly entering the uranium market" for a portion of OPG's supply needs "to mitigate the variations in extremes in market prices". OPG also explained that the strategy needs to take into account "security of supply". In cross examination, OPG further identified that 2 years of uranium concentrate under contract is needed.[118] The application provides a summary of OPG's existing uranium concentrate supply

[114] Tr. Vol. 15, p22
[115] Tr. Vol. 15, p15
[116] ExhF2/Tab5/Sch1/Table 1
[117] ExhF2/Tab5/Sch1/p8
[118] Tr. Vol. 4, p107/ln3-4

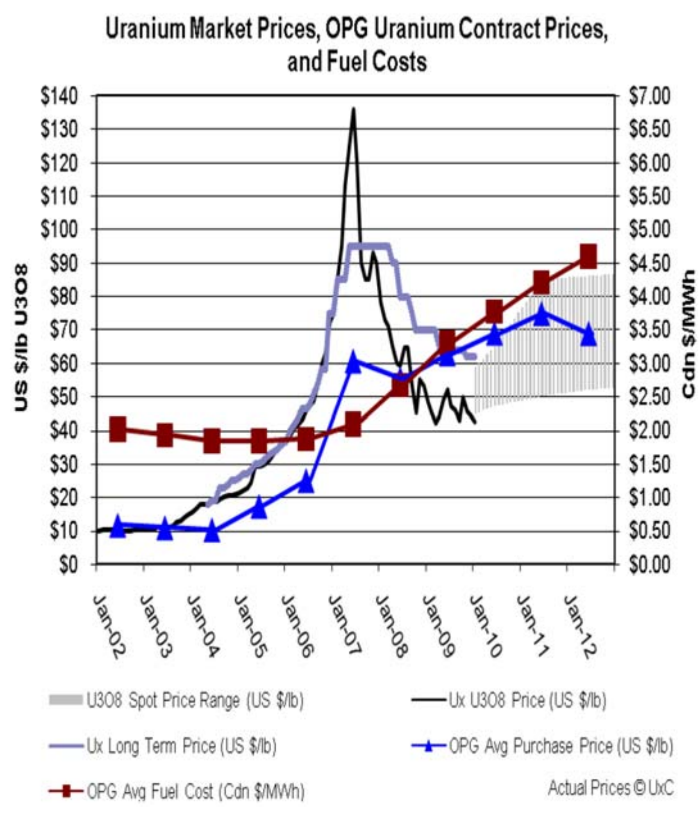
contracts.[119] That chart identifies four contracts, with three entered into at about the same time – first half of 2006 – and the fourth contract relatively soon after that in 2007, just before OPG submitted its first application to the Board. Except for only two spot market purchases in 2009, which were relatively minor in nature with each under $10M[120], OPG has not entered the market at all since 2007. Board staff submits that a situation in which no long-term contract purchases in about *4 years* and all of the current long-term contract supply acquired within about a *1 year* period does not appear to strike an appropriate balance between the objectives of minimizing the cost and security of supply nor does it appear to constitute "regularly entering the market". OPG's track record, based on the evidence in this case, appears to indicate that OPG is placing virtually all of its emphasis on "security of supply".

OPG was questioned if they had undertaken a study tracking the cost of indexed contracts versus market price contracts. OPG's response in Undertaking J4.6 indicates OPG has not undertaken such a study.

A member of the Board Panel also asked OPG's witness panel responsible for Nuclear OM&A costs whether they had commissioned any external analysis of OPG's strategy. OPG's response was "no".[121] A subsequent OPG witness panel noted that they found there had been an independent analysis of the strategy "several years ago".[122] A confidential version of that independent review by UxC Consulting (UxC) was provided via an undertaking. It was undertaken in 2007 and presented to OPG in March 2008 and includes UxC's recommendations and OPG's responses to those recommendations.[123] It appears to Board staff that OPG has not implemented all of the recommendations and that the UxC analysis, which was completed prior to regulation by the Board, is not very relevant. It also concerns Board staff that an OPG panel responsible for nuclear fuel was not aware of such a study which was provided to OPG only a couple years ago. This may be due to the fact that OPG has the variance account which allows them to pass all cost increases on to consumers.

[119] ExhF2/Tab5/Sch1/p9, Chart 3
[120] Undertaking J4.5
[121] Tr. Vol.5, p109/ln18
[122] Tr. Vol.15, p63
[123] Undertaking J4.1

Board staff submits that OPG's strategy needs to be more balanced with greater emphasis on "minimizing fuel costs" and questions the prudence of contracting for three to four years of supply within one year, when only two years of supply is required as stated by OPG. OPG's focus on mitigating price volatility, as referenced above, also does not seem relevant when OPG's nuclear fuel costs increase each year regardless of the direction of market prices and OPG's payment amounts are fixed for two years (i.e., remain the same regardless of volatility in market prices). It appears to Board staff that the lack of emphasis on regularly entering the market and minimizing fuel costs contributes to the "disconnect" between uranium prices and OPG's fuel costs as discussed in the application: "This disconnect between the trend in uranium market prices and the trend in nuclear fuel costs is primarily a reflection of the timing of OPG's negotiation of uranium concentrate contract prices, the expiry of previously negotiated supply contracts, fuel inventory management, and inventory accounting." That disconnect is also shown in the chart below, from OPG's application.[124]



[124] ExhF2/Tab5/Sch1/p12

5.3.2 Nuclear Fuel Cost Variance Account

OPG is proposing to continue the Nuclear Fuel Cost Variance Account. Board staff does not disagree with OPG in respect to continuing the Nuclear Fuel Cost Variance Account. However, Board staff believes that the current structure of the Nuclear Fuel Cost Variance Account does not provide appropriate incentives and has resulted in inappropriate outcomes. When this variance account was established, Board staff's understanding was that it was to ensure that both consumers and OPG were held harmless to the extent that actual fuel costs differed from the OPG forecast in its application. However, this has not been the result as discussed below.

Board staff Interrogatory #65 asked OPG about the variance account within the context of 100% of disconnect between costs and prices being passed on to consumers. OPG responded that the underlying premise of the interrogatory is incorrect because the Board could find some of the costs to be imprudent. However, OPG then essentially stated that consumers should pay all the costs as the Board cannot find any costs to be imprudent because that would be using hindsight. OPG's response therefore appears to indicate consumers do bear all the risk. A member of the Board Panel asked the OPG witness, on the assumption that the procurement is found to be prudent, whether the result of the operation of the variance account will be that ratepayers bear the market price risk. OPG acknowledged that "The ratepayers would bear the risk". [125]

Given the "disconnect" between costs and prices, in cross examination, Board staff asked OPG if the variance account reduces their incentive to reduce nuclear fuel costs. The OPG witness replied, "I don't necessarily believe so" and followed with a discussion of OPG's dedicated and professional staff.[126] Staff notes however, in subsequent cross examination, staff questioned OPG on the need to have the hydroelectric incentive mechanism to operate the Beck PGS in the best interests of the market. Counsel to OPG confirmed that OPG would not operate the PGS in the same manner absent that external incentive mechanism.[127]

OPG was asked to confirm whether there are any internal incentive structures to individuals within OPG to procure uranium at low prices. OPG's response[128] discussed

[125] Tr. Vol. 5, p110, ln21-26
[126] Tr. Vol. 5, p104-105
[127] Tr. Vol. 15, p61
[128] Undertaking J4.6

its Annual Incentive Plan ("AIP"), noting management staff (within Nuclear Supply Chain) have an AIP objective of achieving cost reductions from all nuclear supply chain activities which includes a component related to nuclear fuel procurement. Undertaking J14.1 provided more detailed information associated with OPG's AIP and identified that it is based on corporate (50%) and individual (50%) performance objectives and a table summarizing the corporate performance measures shows "Cost Control" has only a 20% weighting. All of the above appears to confirm that the internal incentive is relatively small and OPG would benefit from an external incentive to act in the best interests of consumers in striving to procure uranium at the lowest possible cost.

A member of the Board Panel asked the OPG witness panel whether they pursued any options to try and minimize the cost consequences of contracts, in terms of either trying to get out of the contracts, or to renegotiate the contracts. OPG's response was no and a subsequent OPG witness panel noted "I don't know whether a variance account or not having a variance account would cause us to change our approach in terms of those contracts."[129]

5.3.3 Variance Account Does Not Capture all Nuclear Fuel Costs

In the application, OPG discusses the annual purchase quantities of uranium required to meet nuclear fuel inventory requirements (as well as expected usage) over the 2010 - 2012 period.[130]

In cross examination by Board staff, OPG agreed that nuclear fuel inventory goes into rate base (as a form of working capital) and, if the Board approves a larger amount for working capital than OPG actually uses in the test years, OPG would over-earn for that amount.[131] OPG's response to Board staff Interrogatory #2 shows OPG's nuclear fuel inventory was overstated by $27M during the previous test period -- $14M (2008) and $13M (2009). As a result, staff asked OPG if the Nuclear Fuel Cost Variance Account captures such variances including the associated cost of capital. OPG's Nuclear OM&A panel noted "I don't believe that it does", but that it should be confirmed with OPG's variance account panel".[132] In subsequent cross examination, CME asked whether the

[129] Tr. Vol.15, p.112-113
[130] ExhF2/Tab5/Sch1/p3
[131] Tr. Vol. 4, p108-109
[132] Tr. Vol. 4, p109, line 28

element for nuclear fuel in working capital is captured by the variance account. OPG's response was "No".[133] As such, OPG benefitted in the amount of the cost of capital associated with the $27M in the previous test years (2008-09) because the variance account does not capture the costs related to nuclear fuel inventory in working capital.

SEC Interrogatory #33 identified that OPG has over-forecast its nuclear fuel costs by 7% to 15% over the period 2007 to 2009. OPG's nuclear fuel inventory is overstated due to the fact that OPG has consistently over-forecast its nuclear fuel costs. As such, Board staff is of the view that the current structure of the variance account (i.e., nuclear fuel inventory costs in working capital not captured) provides OPG with an unintended incentive to over-forecast its nuclear fuel costs.

5.3.4 Should the Board restructure the Nuclear Fuel Cost Variance Account?

As currently structured, staff is of the view that OPG's approach to the use of the variance account:

- provides no incentive for OPG to strive to minimize costs;
- removes all the risk from OPG and shifts the risk to ratepayers, while providing OPG with an opportunity to financially benefit;
- does not capture all of the costs associated with OPG's nuclear fuel cost purchases; and
- provides OPG an unintended incentive to over-forecast its nuclear fuel costs.

Board staff does not believe the appropriate approach is to fully remove the variance account (i.e., disallow its continuance). If it was discontinued, staff believes that this would simply provide an incentive for OPG to over-forecast nuclear fuel costs in future cases to ensure they recover their costs.

Instead, given the above, staff submits that the terms of this variance account should be restructured in the following manner:

- A 50/50 sharing of variances if actual costs are above OPG's application forecast. Staff believes this would bring back an incentive for OPG to strive to minimize its fuel cost purchases. On the other hand, if the actual cost is below the forecast cost, the variance account terms would remain as they are today – 100% of variance (i.e.,

[133] Tr. Vol. 15, p24

over-forecast) returned back to consumers. This would ensure OPG does not simply rely on over-forecasting nuclear fuel costs in future applications and consumers should pay no more than the actual cost.

- Staff also proposes that the variance account be restructured to capture the effects of the differences between actual and forecast nuclear fuel costs related to the cost of capital associated with fuel inventory in working capital.

Staff is of the view that such a restructuring of the terms of the variance account will provide OPG with a greater incentive to strive to minimize costs, capture all of the costs associated with OPG's nuclear fuel cost purchases and remove any incentive for OPG to over-forecast its nuclear fuel costs.

5.4 Pickering B Continued Operations

OPG's application sets out a test period nuclear revenue requirement of $92.9M - $50.6M in 2011 and $42.3M in 2012 – for the Pickering B Continued Operations project. The application also requests approval of an incremental $11.7M in OM&A costs associated with the Fuel Channel Life Cycle Management project separately since it supports both Pickering B Continued Operations and Darlington Refurbishment**.** OPG also requested variance account treatment for this project as part of the existing Capacity Refurbishment Variance Account. OPG estimated the benefits of the project to be $1.1B.[134]

5.4.1 Fuel Channel Life Cycle Management project – Double Counting

In cross examination, Board staff identified that the Fuel Channel Life Cycle Management project was already a separate line item in the amount of $8.8M as part of the total project cost of Pickering B Continued Operations (in "Appendix C: Cost Summary" of OPG's Business Case Summary) and asked OPG if this was a case of double counting. OPG initially stated there was no double counting. However, the following day OPG acknowledged there was double counting in noting, "We have discovered in the course of re-reviewing our material that, in fact, there is a double count in our evidence associated with the allocation of the fuel channel life management project to continued ops. The impact of this is we have overstated our revenue

[134] ExhF2/Tab2/Sch3

requirement for the test period: Specifically, for 2011, 4.9 million; 2012, 3.9 million. We regret this error, and we will be adjusting our revenue requirement."[135] As such, since the subtotal of $8.8M (75%) of the $11.7M is already included in the Pickering B Continued Operations project costs, staff submits that OPG should only be awarded $2.9M separately for the Fuel Channel Life Cycle Management project.

5.4.2 Variance Account Treatment

5.4.2.1 OPG Cost Estimate(s) – $300M vs. $190.2M

Staff Interrogatory #67 asked about the substantial range in cost estimates provided by OPG over a relatively short period of time (about 5 months) for the Pickering B Continued Operation project, with $190.2M in the application, $300M in an OPG Press Release before the application was submitted and the same $300M in OPG's "2009 Sustainable Development Report" after the application was submitted. Staff asked further questions at the Technical Conference about the significant cost disparity and OPG stated that the $300M had been "rounded up".[136] Since rounding up by $110M seemed quite inappropriate, Board staff requested a more detailed explanation in cross examination. OPG explained that they added 30% as a contingency and rounded up a further $50M in the $300M estimate. OPG also confirmed that there was no contingency amount at all included in the application cost estimate of $190.2M.[137] Staff asked OPG if they were relying on the variance account as the contingency for this project and OPG noted "That's correct."[138] Staff notes that every other OM&A project in the application includes a contingency amount (in each respective business case summary), including projects that are in the ballpark of only $10M.

5.4.2.2 Request for Variance Account Treatment

As noted above, OPG requested variance account treatment for the Pickering B Continued Operations project as part of the existing Capacity Refurbishment Variance Account.

[135] Tr. Vol. 5, p3
[136] Tr. Technical Conference, p56
[137] Tr. Vol. 4, p124-125
[138] Tr. Vol. 4, p125

There are many instances during cross examination where OPG's Nuclear OM&A Panel explained its certainty that this project will come in on budget and why there is no need for a contingency including the following:

> "We have done water lancing. We have done a number of the other pieces of work. And so we feel confident around the -- around the cost estimate. And so as such, we have not built in a contingency into the project"[139]

> "we have looked at the costs of the work, except for the actual -- the fuel channel project, the work that we've done is work that we have done before".[140]

> "the component which is new activity is only the fuel channel life management component, which would, I would say, would be about 10 to 20 percent of the entire package. The balance of the activities are things that we are currently doing today as part of maintaining the reactor".[141]

In cross examination of OPG's variance account panel, Board staff asked OPG "the company is quite confident with their forecast of the costs for this project. Would you accept that?" OPG responded "Yes". Staff then asked OPG "If you are so certain about your costs for the test years, why do you need a variance account?" OPG's response did not explain why it was necessary.[142]

It is also important to note that OPG does not currently have a high level of confidence that continued operations will be possible as identified in the application and that this is the reason for the fuel channel life cycle management project which OPG believes will be completed by late 2012.[143] OPG also acknowledged the results from the fuel channel life cycle management project could come back negative and, if that is the case, OPG stated "that money would be lost" in reference to the $92.9M requested in the application.[144] In other words, there will be $100M more in stranded costs associated with OPG's nuclear facilities.

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[139] Tr. Vol. 4, p125
[140] Ibid.
[141] Tr. Vol. 5, p23
[142] Tr. Vol. 15, p48-50
[143] Tr. Vol. 4, p117
[144] Tr. Vol. 4, p120

Board staff submits OPG does not need to use the capacity refurbishment variance account. However, if it is determined that the project does need to use the variance account and OPG has cost-overruns, staff submits that OPG must demonstrate in its next application that those cost-overruns were prudently incurred. OPG has stated its certainty around the cost estimates many times in this proceeding as identified above. Staff has concerns and does not believe it is prudent for the most significant OM&A project in this application to be the only one without a contingency amount. It also significantly concerns staff that OPG has stated it is counting on the variance account to the extent a contingency is required and has estimated the cost to be $110M higher (at $300M) in every other OPG document that staff has reviewed.[145]

If it is determined the Board has some discretion and believes using the capacity refurbishment variance account is appropriate for this project, staff suggests limiting it to the component which OPG stated is not a continuation of its routine OM&A activities, that is, only the fuel channel life cycle management project.

4.5.3. OPG's Estimated Benefits of the Project

OPG included in its application a letter provided by the OPA in support of the Pickering B Continued Operations project and referenced it numerous times throughout the hearing process.[146]

OPG stated during cross examination by PWU that they had submitted the business case to the OPA.[147] Since Board staff could not find any reference to the different cost estimate of $184M provided by OPG to the OPA in the business case summary that OPG provided to the Board as part of its application, Board staff asked OPG what business case it was in noting "Essentially, or exactly". OPG's response was "It was the business case summary." [148] SEC subsequently requested an undertaking to file the documentation that OPG provided to the OPA. Undertaking J5.7 shows that the documentation OPG provided to the OPA was in fact not the business case summary. It is simply a three page document comprised of three tables with quantitative

[145] Tr. Vol.4, p125/ln16-20
[146] ExhF2/Tab2/Sch3, Attachment 2
[147] Tr. Vol.4, p53
[148] Tr. Vol.4, p134-135

assumptions based on different scenarios. As such, there is no discussion of the risks identified in the business case summary submitted to the Board. To the extent that the Board will consider the opinion of the OPA, staff believes it is important that the Board take into account that the OPA's opinion was not fully informed.

Staff also notes that the OPA's support is quite qualified and believes the following excerpts from the second page of that OPA letter are important to consider:

> Although the above example illustrates the potential for substantial system benefits, there could be some conditions under which system benefits are substantially reduced or become negative. These include lower than expected system demands, lower than expected gas or carbon prices or higher than expected continued operation costs.
>
> Based on information provided by OPG, the OPA has assessed that the continued operations of Pickering NGS will provide electricity at a price of approximately $50 per MWh.

Board staff believes that the use of a price of approximately $50/MWh is inappropriate in assessing Pickering relative to replacement generation. That figure is not only less than the current (or proposed) OPG payment amounts, Board staff believes the appropriate figure to use for comparison purposes for replacement generation is the Total Generation Cost (TGC) at the Pickering stations (i.e., not a figure close to the payment amounts that also takes into account the much lower cost Darlington station). OPG's projected TGC for Pickering A in 2010 is about double the assumed cost for estimating the benefits at $102.4/MWh, with Pickering B's TGC about $10/MWh higher at $61.7/MWh.[149] The benefit of $1.1B estimated by OPG is also highly dependent on a carbon price in place and there is no evidence in this case that a carbon price will exist at all. Moreover, in response to Staff IR #69, OPG provided the various assumptions underlying the benefit estimate.

- For 2016-2020, OPG assumed a unit capability factor (UCF) ranging between 85.9% and 90.5% (Pickering A) and 78.6% and 91.5% (Pickering B). Board staff notes however, that Pickering A's actual UCF for 2009 was only 64.2% and OPG now

[149] Undertaking J3.3

projects 63.9% (vs. budget of 73.7%) for 2010. For Pickering B, actual UCF for 2009 was 84% and OPG now projects 75.2% (vs. budget of 76.1%) for 2010.[150]

- OPG also identified that virtually all of the replacement generation is assumed to be natural gas. OPG's forecast gas price is between 6.8 and 7US$/mmBTU. Staff Technical Conference Question #23[151] asked OPG whether they believed their long-term gas price forecast remained reasonable given it was prepared some time ago and the results of OPG's short-term forecast seemed high in assuming 5.7 (2010) and 6.6 US$/mmBTU (2011). In contrast, the U.S. EIA's Short-Term Energy Outlook — August 2010 is projecting gas prices of only 4.69 (2010) and 4.98 (2011). The current spot price at the time of the Technical Conference was even lower at 4.3 US$/mmBTU.

Given all of the above, staff believes OPG's estimate of the benefits associated with Pickering B Continued Operations is significantly overstated. Board staff submits that OPG should provide further evidence, including independent analysis of the benefits of the project, to support future cost recovery.

5.5 Compensation

Board Staff Interrogatory #74 requested the aggregate compensation costs (inclusive of Total Wages, Benefits, Pension/OPEB) over the 2007-2012 period. The total requested compensation costs for OPG's regulated operations are $1,381.74M in 2011 and $1,402.16M in 2012 (or almost $2.8 billion over the test period).

In cross examination, Board staff asked OPG "would it be accurate to say that with regard to the compensation OPG pays its employees, would you accept that OPG should be paying market rates for labour?" OPG's responded "That would be our goal, yes."[152]

[150] Undertaking J6.5
[151] Tr. Technical Conference, p57
[152] Tr. Vol. 8, p149

5.5.1 OPG 6% above 75th percentile, 16% above the 50th percentile

OPG's application includes a chart "OPG's Salary Variance From the 75th Percentile".[153] The chart is based on data from a survey of the Power Services Industry conducted by Towers Perrin. The Towers Perrin survey was not prepared specifically for OPG and includes data for many different job descriptions. OPG selected what they believed were the appropriate comparators that were presented in the application without input from Towers Perrin. OPG selected 30 positions from the survey throughout OPG and compared them to the 75th percentile of market data in the chart. The application notes "OPG is slightly above the 75th percentile of market on an overall basis". Board staff interrogatory #81 identified that 64% of the positions selected by OPG are above the 75th percentile and, on an overall basis, OPG is 6% above and asked why OPG considered 6% to be "slightly" above. OPG explained that the definition of 'on market' accepted within the compensation industry is within plus or minus 10% of the market rate. The interrogatory also asked OPG why they use the 75th percentile as a benchmark instead of the 50th percentile. OPG explained that while Towers Perrin provided information on the mean, 10th, 25th, 50th, 75th and 90th percentiles, OPG noted in the interrogatory response that they chose to use the 75th percentile "because of the relative complexity of work in a large, regulated and nuclear environment".

In cross examination[154], staff asked OPG about their rationale for selecting the 75th percentile. OPG first acknowledged that a number of the comparators were also large. OPG also acknowledged that at least four of the comparators were also regulated by the CNSC. The OPG witness doubted whether regulated entities provided greater job security, but agreed that government owned entities did provide that security. Board staff also questioned OPG about another reason in asking "labourer is in there, junior buyer, environment fully qualified. So there is a number that are not nuclear positions; you accept that?" OPG responded "There are a number that are not nuclear positions." The witness was not able to identify a single position in the chart that is definitely a nuclear position.

Staff also notes that working in a nuclear environment would not be applicable to many of OPG's staff working in their Hydroelectric and Corporate groups. In addition, the Towers Perrin study focuses solely on base wages as opposed to total compensation

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[153] ExhF4/Tab3/Sch1/p30 Chart 11
[154] Tr. Vol. 8, p163-170

and a number of OPG staff working in a nuclear environment receive relatively substantial bonuses as identified in OPG's response to staff interrogatory #79. Board staff submits that the rationale provided by OPG for use of the 75th percentile is not justified and staff believes that the 50th percentile is more appropriate. Staff further submits that the 50th percentile is also more consistent with the use of the median by the Board in relation to Hydro One as discussed below.

SEC interrogatory #36 asked OPG to replicate chart 11 using the 50th percentile. In cross examination, Board staff asked OPG to confirm that out of the 30 positions "only two of the positions you have selected would come underneath at the 50th percentile? That would be operating technician entry and industrial nurse?" OPG confirmed that was correct. Staff estimated that, on average, the 30 positions are 16% over the 50th percentile. The witness agreed that if the 50th percentile was the right market reference, that OPG would be above market. Staff noted that a number of the positions earned significantly above the 50th percentile, such as warehouse supervisor (30%), labourer (21%), and junior buyer (23%), and appeared to be "generic" positions.[155] In contrast, in regard to the two OPG positions that were below the 50th percentile, staff notes that they were only 3% below.

Undertaking J8.6 required OPG to provide its best estimate of the impact of adjusting labour costs to the 75th percentile and to the 50th percentile. OPG's response identified in order to get to the 75th percentile for the 30 occupations in the chart approximately $16M would need to be removed from the payroll. To move to the 50th percentile for these occupations would require removing approximately $37.7M from the payroll. OPG identified that it does not have information that would allow it to calculate the difference between existing average salaries and the 75th or 50th percentile for the remainder of its represented incumbents. Staff notes that these occupations represent a relatively small subset and the dollar amounts noted above are therefore based on only 28% of the incumbents in OPG's regulated operations. Given that 28 of 30 OPG positions (or 93%) were above the 50th percentile, the results based on the 30 occupations are likely representative of all union-represented jobs in OPG's regulated business. If that is the case, the amounts OPG provided as identified above would be almost four-fold higher. Staff therefore submits that at least $37.7M should be removed from OPG's annual revenue requirement. This would represent 2.7% of OPG's aggregate compensation costs.

[155] Tr. Vol. 8, p171-172

5.5.2 OPG comparison to successor companies

OPG provided a comparison of OPG to Hydro One for the Society showing various wage comparisons and they were comparable. [156]

Staff entered into evidence a similar chart for certain PWU positions from Hydro One's application.[157] In cross examination, staff pointed out that there was no PWU comparison in OPG's application. Staff reviewed comparisons from the chart prepared by Hydro One in noting "mechanical maintainer, they say they pay 38.30; you pay 44.72. Shift controller, 38.30 versus 44.72. The next two clerical positions, you look actually pretty much the same. Then we get to regional field mechanic, 35.56 versus 44.72. And I hate to keep picking on the poor labourers, but here we have 25.82 for Hydro One and 34.79 for OPG." Staff then asked OPG "do you have any cause to disagree with the numbers they have here? Have they done something improper?" OPG responded "Not that I am aware of." OPG subsequently noted they were "fairly generic-type jobs."[158] Board staff submits that there is no justification for OPG to be consistently paying their staff so much more than Hydro One for staff in generic positions.

Board staff explained that, in a recent Hydro One case, the Board made certain reductions to revenue requirement based on what the Board found to be excessive compensation levels. OPG confirmed it was aware of the case. Staff then noted "I don't want to be seen as picking on either Hydro One or OPG, but if you'll permit me an observation, it seems the successor companies -- many of them are regulated before us, they bring rates applications -- they all seem to be able to produce a chart much like you have in your application and Hydro One in theirs, where they're able to show by some accounting method that they're doing better than all their comparators." OPG responded "And so depending on how you slice the data, you can get all kinds of different comparisons."[159]

Staff questioned OPG as to whether they had considered a third party thorough review

[156] ExhF4/Tab3/Sch1/p34 Chart 13
[157] ExhK8.3, p13
[158] Tr. Vol. 8, p189-190
[159] Ibid., p190-191

of their compensation levels and benchmarking similar to the Mercer compensation study that the Board required Hydro One to undertake. OPG explained that Mercer has been hired to undertake compensation benchmarking studies for management but not for the PWU and the Society. OPG further explained "It is a very expensive undertaking. It would be significant, in terms of several hundred thousand dollars it would take, because it would have to be custom."[160]

Board staff submits that OPG should be required to retain a third party expert, to complete a comprehensive study similar to the study that was required of Hydro One which compares total compensation (i.e., not only base wages as OPG has focused on). Given total compensation costs of almost $2.8 billion over the test period, an expense of several hundred thousand dollars for thorough and independent benchmarking is very reasonable. As OPG noted, "depending on how you slice the data, you can get all kinds of different comparisons." Board staff therefore believes an independent benchmarking study is necessary.

5.5.3 Test Period Wage Increases

The response to Board staff interrogatory #75 identifies that the current PWU collective agreement expires on March 31, 2012 and the Society's expires December 31, 2010. The response identified that the projected general wage increases built into test year OM&A budgets was 4% per year. The 4% is based on historical increases of 3% per annum and also takes into account staff progressions and promotions.[161]

Staff entered into evidence the Government's Policy Statement in regard to Public Sector Compensation Restraint.[162] It states "Employees who are part of a union … would see their current agreements honoured. When these agreements expire and new contracts are negotiated, the government will work with transfer payment partners and bargaining agents to seek agreements of at least two years' duration that do not include net compensation increases….It doesn't matter whether contracts expire next month, next year or the year after that – all employers and employee groups will be expected to do their part." As noted above, the Society collective agreement expires at then end of 2010. In cross examination, staff asked whether OPG was taking a business-as-usual

[160] Tr. Vol. 8, p192-193
[161] Tr. Technical Conference, p177-178
[162] ExhK8.3, p10

approach to budgeting the historical average of 4% salary increases for the unionized employees. OPG responded that "We are assuming that there may be a requirement to pay up to that, depending on what the outcome of negotiations is."[163] Staff then referenced three recent arbitration decisions entered into evidence by the PWU. Those decisions resulted in increases of 2%, 2.25% and 3%. OPG acknowledged that the three arbitration decisions average less than 3%. Staff recommends that a salary increase of 2.5% for Society staff, inclusive of progressions, be allowed for the purpose of determining OPG's revenue requirement. Staff notes that the total salary and wages for Society staff on an annual basis is approximately $370M[164], and that a 1.5% lower salary increase would amount to a revenue requirement impact of $11M for the test period.

5.5.4 Approved vs. Actual Nuclear FTEs in previous test years (2008-2009)

Board staff submitted into evidence an exhibit from the previous payments proceeding showing OPG's Nuclear staff numbers that were requested and approved for 2008-2009 – the previous test years.[165] In cross examination, the OPG witness stated that it would be reasonable to assume the compensation amounts associated with those employee numbers formed part of the revenue requirement.[166] Staff identified that the Actual Regular FTEs were 1,362.9 lower and Non-Regular FTEs were 821 higher over the two year period in OPG's current application.[167] Staff also entered into evidence an interrogatory filed by SEC in the last proceeding in which OPG provided the average employee costs for the nuclear business for 2005 for regular and non-regular staff that did not include "Benefits", which regular staff receive and non-regular staff do not receive.[168] Based on the difference in the staff numbers and the average cost per employee, Board staff calculated that it amounted to about $106M.[169] Staff noted that the $106M was an estimate of the revenue that OPG appears to have collected on account of its last rate application that they did not actually spend on employee compensation. OPG did not concur with the $106M estimate citing that the staff numbers were based on FTEs in the previous application and headcount in the current

[163] Tr. Vol. 8, p201
[164] Undertaking J9.6
[165] ExhK8.3, p10
[166] Tr. Vol. 8, p208
[167] ExhF2/Tab2/Sch1 Table 13
[168] ExhK8.3, p24
[169] ExhK8.3, p67

application. Board staff then noted “I would like to provide this opportunity that I think you can take or not. But if OPG is able to present what the numbers should be, how we got it wrong, we would be happy to see OPG's calculation of that.” OPG responded “I am not sure that that is possible, because we are really comparing apples to oranges.” [170]

As noted previously on page 50, OPG provided FTE and headcount in the response to undertaking J4.4. Staff notes that the difference between headcount and FTEs was relatively minor in 2008 and 2009 at 46 and 35 (and 81 in total) versus the difference of 1,362.9 in Regular staff FTEs between the two applications over the same period. Staff also notes that, to the extent the calculation is overstated, it would be offset to some extent due to the fact that average employee costs for the nuclear business used in the calculation were quite dated (2005) and it excluded “Benefits” as noted above. Based on the information provided in that undertaking by OPG, Board staff submits that the calculation of $106M was in fact in the ballpark. As noted above, in the absence of other information, OPG appears to have collected $106M on account of its last proceeding that it did not spend on employee compensation and Board staff submits this should be taken into account in determining the appropriate compensation amount to be included in OPG’s revenue requirement.

5.6 Corporate Costs – Regulatory Affairs

OPG’s proposed OM&A includes $6.356M in 2011 and $9.570M in 2012 for Regulatory Affairs. The budget consists of: recurring costs, EB-2007-0905 costs, EB-2010-0008 costs, other regulatory proceedings and OEB annual assessment.[171]

Board staff submits that the provision for Regulatory Affairs in the 2011 and 2012 is excessive and should be reduced by at least $2.283 M and $1.908 M respectively.

[170] Tr. Vol. 8, p211-212
171 Issue 6.9, ExhL/Tab1/Sch103 p.2

5.6.1 Budget vs Actual

The proposed Regulatory Affairs budget for 2011 and 2012 shows an increase, as compared to 2008 actual, of $1.069 M or 20% and of $4,283 M or 81% respectively. The actuals for 2008 represent a high activity year in that they include most of the expenditures related to the EB-2007-0905 proceeding. In comparison, the actuals for 2009, a year in which there was no major rate case, shows a decrease of $1.241 M as compared to 2008 actuals.

Using 2008 actuals and 2009 actuals as benchmarks for a “rate case” year and a “non rate case year”, one would expect the proposed budget for 2011 and 2012, with inflation at 3% per annum, to be in the range of $4.3 M and $6.0 M respectively. Instead OPG is proposing a budget that exceeds a benchmarked projection, by about $2.1 M in 2011 and $3.6 M in 2012.

Regulatory Affairs

(in thousands)		(a)	(b)		(c)	(d)		(e)	(f)	(g)
ITEM	2007 Actual	2008 Board Approved	2008 Actual	variance (b)-(a)	2009 Board Approved	2009 Actual	variance (d) - (c)	2010 Budget	2011 Plan	2012 Plan
Recurring Costs										
sal/wages, operating expenses	2,376		2,097			2,531		3,039	3,129	3,291
EB-2007-0905										
legal costs	296		615							
expert witnesses/consultants	90		493							
intervenor cost awards			1,407							
section 30			223			5				
other										
total	386		2,737			5		0	0	0
EB-2010-0008										
legal costs								1,500		
expert witnesses/consultants						124		1,250		
intervenor cost awards								1,890		
section 30										
other										
total						124		4,640	0	0
Other Regulatory Proceedings										
legal costs						241			500	1,500
expert witnesses/consultants						5			800	1,150
intervenor cost awards	100					59			300	1,985
section 30										
other	52		108			138		134	127	144
total	152		108			443		134	1,727	4,779
OEB Annual Assessment			345			944		980	1,500	1,500
Other										
total										
Grand total	2,914	0	5,287	0	0	4,046	0	8,793	6,356	9,570

Source Issue 6.9, ExhL/Tab1/Sch103

OPG's witness testified that in 2010, which is a rate case preparation year, Regulatory Affairs provided, by way of additional staff, much more support to other departments involved with the current case, and as a result there was less excessive demands placed on the other departments. The witness noted that the 56% increase in recurring costs, between 2008 actual and 2012, reflects the amount of effort that now goes into a rate hearing. While concurring that the staff additions account for most of the increase in recurring costs, the witness was unable to indicate what the staffing levels were between 2008 and 2010 in this regard, [172]

5.6.2 OEB Assessment and Legal Costs

OPG's provision for the OEB assessment in 2011 and 2012 increased by about $0.556M as compared to 2009 actual and by $0.550M as compared to the budget for 2010. OPG's witness explained that their forecast of a $1.5M OEB assessment for the test period was based on inquiries they had made from other companies who generally answered that the assessment would be "Considerably more than a million dollars a year"[173]. In response to undertaking J9.9, OPG indicated that its 2010 OEB assessment is $0.805 M. There therefore appears to be little justification for the forecast of $1.5M.

In explaining the increase in legal costs, as compared to the EB-2007-0905 proceeding, OPG's witness noted that their year-to-date experience is pretty much on track with the projection for 2010 and indicated that it had to do with the issues in the current proceeding, such as Darlington Refurbishment, which added to the costs. The witness noted that although no intervenor claims have been filed yet for this proceeding, OPG anticipates higher intervenor costs " figuring they would be somewhat higher than the last time, that the questioning and sophistication of the intervenors would be that much more than the first time, where it was a lot of a learning process."[174]

Based on the evidence and testimony, Board staff submits that the proposed Regulatory Affairs budget for 2011 and 2012 is overstated and should be reduced.

In the first instance, a simple benchmarking approach, indicates that a reduction of up to $2.1M in 2011 and up of $3.6 M in 2012 may be warranted.

[172] Tr. Vol. 8 p139-140
[173] Tr. Vol. 8 p141 ln14
[174] Tr. Vol. 8 p143 ln 8-11

In the alternative, on the basis of a line by line analysis, Board staff proposes the following reductions.

Reductions in Millions	**2011**	**2012**
½ of the increase in recurring costs as compared to 2009 actual because OPG provided an incomplete explanation.	$.299	$.380
½ of the increase for the 2013-14 proceeding as compared to actual for EB-2007-0905 since the latter is the only actual, and not anecdotal basis for comparison	N/A	$.828
Unexplained increase for "other regulatory proceedings" in 2011 as compared to 2009	$1.284	N/A
No basis for assuming OEB annual assessment for 2011 and 2012 will be 50% higher than 2010	$.7	$.7
TOTAL reduction	**$2.283**	**$1.908**

5.7 Centrally Held Costs - Nuclear Insurance

OPG is requesting an increase in Nuclear Insurance costs, which is categorized as a Centrally Held Cost. The forecast is almost double in the test years, from $7.3M (2009) to $13.4M (2012).[175] The application notes the following in explaining the increase, "The forecast nuclear insurance costs are higher primarily due to the increase in nuclear liability insurance requirements by the federal government."[176] Board staff asked about those federal government requirements in Board staff interrogatory #89. OPG's response identified that Bill C-15 is only a proposed bill and noted "OPG's best estimate is that the NLCA will receive Royal Assent at the end of 2010 or early in 2011". A status update was requested by staff during the oral hearing and OPG identified "Bill C-15 is in Debates at Second Reading." [177]

[175] ExhF4/Tab4/Sch1/Table 1
[176] ExhF4/Tab4/Sch2/p4
[177] Undertaking J10.12

Staff submitted into evidence an article by a Toronto-based legal firm – Davies Ward Phillips & Vineberg LLP - entitled “Federal Government Reintroduces Proposed Changes to Nuclear Liability Legislation”[178] This article provides a summary of the history behind Bill-C-15 and notes:

> Bill C-15 is in substance identical to numerous other bills that have been introduced by the federal government over the past three years to amend and replace the existing Nuclear Liability Act, each of which has died on the Order Paper….The federal government has been attempting to modernize Canada's nuclear liability regime for decades, but earlier attempts have either met with constitutional challenge or died on the Order Paper.

In cross examination, the OPG witness agreed that if the legislation does not pass, OPG would over-recover by $6-$7 million. The witness also stated that if the bill passes, the insurance costs could be higher than forecast.[179] Board staff suggested that it might be appropriate to have a variance account, given the uncertainty whether or not Bill C-15 will actually receive Royal Assent in the test years. OPG’s witness responded, “I don't think that is a very good idea” and noted that was because “the amount of money that we're talking about is not material, in the context of the materiality standard that the Board normally applies for variance accounts.” [180] The witness further observed that if a standard of absolute certainty applied to forecasting costs, there would be a variance account for nearly everything.

Staff notes that including costs based on proposed legislation (or regulation) is not consistent with the Board’s approach in setting the current Regulated Price Plan (RPP) prices. At the time of the RPP price change, the regulation which changed how the Global Adjustment is charged was only proposed. As a result, the Board noted in its RPP Price Report “This change has not been implemented in this report because the proposal has not been finalized through Regulation. To the extent that there are changes in the Global Adjustment allocation after November 1, 2010, the RPP variance account will capture these changes and the impact will be incorporated into RPP prices later.” [181]

[178] ExhK15.1/p3
[179] Tr. Vol. 15, p47
[180] Tr. Vol. 15, p45-46
[181] RPP Price Report, October 18, 2010, p11

Given the above, Board staff submits the proposed increase in Nuclear Insurance costs should not be included in OPG's approved revenue requirement. Staff agrees with OPG that such amounts are too immaterial to create another variance account in respect of OPG. Board staff therefore suggests that, if Bill C-15 does in fact receive Royal Assent this time after failing to do so many times before, the associated cost increase going forward be addressed in OPG's next application. Staff also notes that it is nearing the end of 2010 (when OPG assumed Bill C-15 would receive Royal Assent) and the bill is only in debates at second reading. As such, staff believes OPG's estimated cost increase of $6-$7 million is likely also overstated in any event. If that is the case, the materiality would be lower than OPG's forecast if Bill C-15 does actually receive Royal Assent during the test period.

5.8 Depreciation

OPG's total depreciation expenses are $622.4M (comprised of hydroelectric of $130.6M and nuclear of $491.8M) for the 2011-2012 test period.

OPG's 2009 Depreciation Review Committee ("DRC") report[182] indicated that the DRC as of 2009 has reviewed nuclear asset classes with a total net book value of approximately $1.9 billion, representing approximately 74% coverage of total nuclear asset net book value.

The 2009 DRC report, regarding the DRC's Nuclear Assets Review for 2009 at Appendix C, showed a clear trend of increases to the useful lives of many assets, which caused annual reductions to depreciation expenses starting in 2010. For the test period, this has resulted in reductions to depreciation expenses of $12 M. In addition, the review showed no increases to depreciation expenses for any of the assets reviewed.

Therefore, if the remaining 26 percent of nuclear facilities (or about $684 M), that received no coverage were to be reviewed by DRC in the future, there is a very reasonable expectation that the outcome of such review may result in overall longer useful lives being assigned to many of these remaining assets. This would result in

[182] ExhF4/Tab1/Sch1, Attachment 1, Executive Summary

further reduction to depreciation expenses. As a result, Board staff submits that OPG's depreciation expenses for the two-year test period may be overstated. The extent of this overstatement is not easily quantifiable in the absence of a detailed depreciation review or an independent depreciation study.

Board staff does not know whether the depreciation expenses for the test period are accurately reflected in the revenue requirement because OPG has never conducted an independent depreciation study detailing a comprehensive review of the useful lives of its regulated assets and the Bruce stations. Staff notes that the Board has relied on independent depreciation studies from large utilities, and in some instances has ordered the commissioning of such studies, in order to determine the appropriateness of depreciation expenses.

Board staff notes that other large utilities in numerous regulatory proceedings have produced independent studies to support their depreciation expenses (e.g. Enbridge, Union and Hydro One). In 2010, the Board commissioned an independent depreciation study to assist electricity distributors in their accounting transition to IFRS. The Board received several comments on the subject of depreciation studies in its consultation on this matter (EB-2010-0178 – "Depreciation Study for Electricity Distributors – Transition to International Financial Reporting Standards (IFRS)". A letter of May 21, 2010 (pages 1 and 2) from Hydro One included the following:

> "Hydro One carries out external depreciation reviews because external review provides for high quality and independent regulatory support for an expense category that is very material to our revenue requirement. The use of an external consultant was initially ordered by the Board in Networks' Distribution and Transmission transitional rate orders for 2000 and 2001.
>
> The fact that depreciation service life recommendations are made by an expert external consultant provides additional assurance to our external auditors and, indirectly, to other financial statement users that the depreciation expense and related asset carrying values included in our external financial reports are appropriate. As we are a public securities filer, it is critical that all management estimates that impact the balance sheet or income statement are credible. External expert review supports the assertion that the service life estimates we

> apply in arriving at reported depreciation expense appropriately reflect expected asset useful lives."

Board staff submits for OPG's next payment application, the Board should require OPG to provide an independent depreciation study detailing a comprehensive review of the useful lives of its regulated assets and the Bruce stations. The impacts arising from the results of the study should be identified and incorporated in the next test year(s) revenue requirement for Board review.

5.9 Harmonized Sales Tax

The Harmonized Sales Tax ("HST") came into force in Ontario on July 1, 2010. Utilities that received rate orders from the Board in early 2010 or before have been recovering applicable Ontario Retail Sales Tax ("RST") in rates as part of their revenue requirement. In order to forecast the correct costs for 2011 cost of service applications, the embedded RST (or provincial sales tax) must be removed.

Minister Brad Duguid wrote to OPG on May 5, 2010 and in the letter addressed the impact of HST.

> Also, as part of OPG's efforts to mitigate rate pressures and consistent with the government's policy on the introduction of the harmonized sales tax (HST), I would request that OPG commit to returning to ratepayers the full cost reduction impact of input tax credits from items that were previously subject to the Retail Sales Tax (RST).[183]

In response Mr. Tom Mitchell, President and CEO, wrote to Minister Duguid on June 24, 2010.

> Your letter specifically references the need to return to ratepayers the savings that result from the introduction of the harmonized sales tax (HST). I can confirm that this is part of OPG's plan. The introduction of the HST produces a small net benefit for OPG, and the rate application includes the savings for ratepayers that are attributed to our regulated assets.[184]

[183] Issue 1.3, ExhL/Tab4/Sch1/Attachment1
[184] Issue 1.3, ExhL/Tab4/Sch1/Attachment2

OPG's forecast for the test period incorporates a net reduction to costs as a result of the HST. The reduction is estimated to be less than $5M annually.[185]

OPG calculated the benefit related to the prescribed facilities for July 2010 to be $570,000.[186] In reply to an undertaking from the technical conference, OPG estimated the annualized benefit to be approximately $6.0 M.[187] OPG provided additional information that the estimated net HST savings for August were $484,000 and $476,000 for September.[188]

Staff understands that it is difficult for utilities to estimate the annual savings since the HST returns and related Input Tax Credits ("ITC"s) have only been filed with Canada Revenue Agency for a few months in 2010. Added complexity is created with the restrictions imposed on large businesses related to recaptured ITCs.

Staff submits that OPG should further decrease costs to reflect the net reduction of approximately $6M instead of the less than $5M currently included in test period costs.

Staff submits that OPG should report back to the Board in its next application with details of twelve months of HST returns and the ITC amounts related to the prescribed facilities to validate its estimates used in the current application and its compliance with the Minister's request. OPG can propose in that application how it should deal with the difference between $6M and the updated numbers if the difference is material.

5.10 OM&A SUMMARY TABLE

Board staff submits that OPG's OM&A for the 2011 and 2012 test period should be reduced as follows:

($ millions)	2011	2012
Saunders Visitor Centre OM&A p21	$0.5	$0.5
Target Forced Loss Rate (FLR) – Removal of outlier from historical average p44	$7.0	$7.0

185 ExhF4/Tab2/Sch1/p24
186 Tr. Technical Conference August 26, 2010, p116
187 Undertaking JT1.9
188 Undertaking J15.1

Radiation Protection Function – Retention of unnecessary staff p47	$2.2	$2.2
Fuel Channel Life Cycle Management project – Double counting[1] p60	$4.9	$3.9
Compensation – Change from 75th to 50th percentile p66	$37.7	$37.7
Society Increase of 2.5% instead of 4% p69	$5.5	$5.5
Regulatory Affairs p73	$2.3	$1.9
Nuclear Insurance – Legislative changes only proposed p74	$3.5	$3.5
HST understated p78	$1.0	$1.0
Total	**$64.6**	**$63.2**

[1] OPG already agreed this revenue requirement reduction is necessary.

6. DEPRECIATION AND SERVICE LIFE OF STATIONS

For accounting purposes, several issues were raised in relation to the appropriateness of the end date of service lives OPG uses for the Pickering A, Pickering B and Darlington nuclear stations. These concerns are in addition to those staff has expressed with respect to the capitalization of the Darlington refurbishment costs. For depreciation purposes, in the case of the Darlington station, OPG has changed the end of service life from 2019 to 2051 due to the approval of the definition phase of the DRP. In another case, OPG did not change the end of service life of the Pickering B station currently under review to determine whether the station operations can continue beyond 2014. The 2009 DRC report made these recommendations, which were approved by OPG's senior management (Approval Committee), effective January 1, 2010.

For accounting and depreciation purposes, the end of service live for Pickering B is September 30, 2014. OPG has indicated that it has embarked on a work program (including physical work in the plant, laboratory tests, analytical work and discussions with the nuclear safety regulator) to demonstrate high confidence in extended service lives of the Pickering B pressure tubes. If successful, OPG states it would expect to be able to operate the Pickering B units under "Continued Operations" scenario until 2018 to 2020. The 2009 DRC report concluded that OPG cannot currently claim high confidence, for accounting purposes, in achieving continued operations, but expects to be able to claim that high confidence by approximately the end of 2012.

The matter is further complicated given the interdependence of Pickering A (units 1 and 4) and B from operational and economical perspectives. For accounting and depreciation purposes, the end of service lives for Pickering A (units 1 and 4) is December 31, 2021. Without the continued operations of Pickering B beyond its current service life, it raises uncertainty about Pickering A as a going concern for accounting purposes.

Due to the uncertainty of the expected outcome on the success of the Continued Operations and the completion of the Darlington refurbishment, OPG was asked and has provided the revenue requirement impacts under four scenarios where different assumptions are made regarding the end of service lives dates for the Pickering A, Pickering B and Darlington nuclear stations (Undertaking J10.11). The total revenue requirement impacts were increases of: $6.7M under scenario 1A, $558.1M under scenario 2, $245.5M under scenario 3 and $242.5M under scenario 4A.

Staff notes that each scenario results in accounting changes to the depreciation expenses, the accretion expenses, income taxes, the net book value of the nuclear station fixed assets, the nuclear liability (ARO) and the revenues and cash flows due to the changes in the revenue requirement. Any of these scenarios if adopted for ratemaking purposes, would introduce a separate and second set of books that may differ significantly from OPG's GAAP-based financial accounting and reporting. The regulatory accounting information (i.e., second set of books) not underpinned by GAAP-based accounting could introduce many complexities in the regulatory process including a lack of comparison to reported audited financial information, financial performance and benchmarking issues.

However, OPG can be required to provide reconciliations for differences between financial and regulatory accounting reporting should the Board be inclined to accept any of the four scenarios for ratemaking purposes.

Staff submits that the Board could elect to:

1. Not approve the base revenue requirement impacts as filed in the application and direct OPG to use one of the scenarios although this would result in incremental regulatory accounting requirements; or
2. Approve the base revenue requirement proposed but indicate that such approval does not imply Board's approval of the refurbishment project at this time.

7. PRODUCTION FORECAST

7.1 Hydroelectric Production Forecast

OPG seeks approval of a production forecast of 38.4 TWh for the test period for the regulated hydroelectric facilities. OPG proposes to include in that forecast allowances for expected surplus baseload generation ("SBG") conditions that reduce the hydroelectric production forecast accordingly.

7.1.1 Background

OPG's hydroelectric production forecast is based on forecasting water flows in the Great Lakes Basin assuming "normal" weather conditions. The forecasting methodology is conventional and non-controversial. When OPG substitutes actual inputs for assumed inputs in its forecasting model, the model simulation replicates actual production. OPG's pre-filed evidence shows that its forecasts have under estimated actual production in the 2007-09 period, as illustrated in the table below.

In its pre-filed evidence OPG has assumed that SBG conditions will occur in 2011 and 2012 and has reduced its production forecast through adjustments in those years. OPG's assumed SBG impacts are 0.5 TWh in 2011 and 0.8 TWh in 2012. According to undertaking J1.1, in 2010 from January 1st to October 3rd, SBG conditions have resulted in 20.4 GWh (0.02 TWh) of spilled water which appears to be considerably lower than OPG's 2010 forecast of 0.2 TWh.

OPG did not include SBG adjustments in its previous filing (EB-2007-0905), however OPG notes that SBG conditions occurred in 2009.[189]

Table: Regulated Hydroelectric Production (TWh)[190]

	2007	2008	2009	2010	2011	2012
Forecast	17.5	17.4	18.5	19.3	19.4	19.0
Actual	18.2	19.0	19.4			
Variance	0.7	1.6	0.9			
SBG in Forecast				(0.2)	(0.5)	(0.8)

7.1.2 Hydroelectric Water Conditions Variance Account

The financial impact of production forecast variances that are the result of actual water conditions varying from forecast water conditions are collected in a “hydroelectric water conditions variance account”. Although OPG expends considerable effort to forecast water conditions there is a high probability that actual conditions will vary from forecast because of the random variability associated with weather forecasting and water flows. These variations in water conditions are the result of natural conditions and are not under OPG’s control. Therefore, production that deviates from forecast as a result of these natural variations does not financially benefit, or penalize, OPG or consumers.[191]

7.1.3 Surplus Baseload Generation

According to testimony on October 4, 2010[192], SBG conditions arise when the baseload generation available exceeds energy demand in the Ontario system. For operational purposes, OPG often responds to SBG conditions by spilling water, i.e., choosing to not generate energy, at its designated hydroelectric facilities. Spilling water is often the most cost effective way to respond to SBG conditions. In addition, the IESO can order OPG to spill water to ensure the reliable operation of the Ontario electrical system.

[189] ExhE1/Tab1/Sch1/p5
[190] ExhE1/Tab1/Sch2/Table 1
[191] Tr. Vol. 1, p77
[192] Tr. Vol. 1, p66-72

Further testimony[193] established that the conditions that result in SBG are outside of OPG's control and that including allowances for SBG reduces OPG's production forecasts, all else being equal. The witnesses also confirmed the response to CME IR#024[194]. OPG estimated that the hydroelectric revenue deficiency would be reduced by a total of $32.5M if there were no SBG adjustments to forecasted production.

As currently constructed, OPG's production forecast is reduced by the allowance for potential SBG conditions in the test years. A reduced production forecast results in an increase in unit payments for energy, all other things being equal. Allowing SBG adjustments to the production forecast essentially indemnifies OPG from the financial impacts of SBG.

Board staff notes that SBG conditions are qualitatively equivalent to deviations of actual water conditions from forecast water conditions. Both conditions are outside the control of OPG and both change the revenues that OPG collects from hydroelectric production.

However, staff notes two important differences between these two sources of changes in forecast production. First, the impacts of SBG, as proposed by OPG, are accounted for before they occur, i.e., they are treated as a "forecast certainty", while deviations in water conditions are accounted for after they occur through a variance account. Second, the financial benefits of including SBG in the production forecast are "one way", accruing exclusively to OPG, i.e., if SBG does occur, OPG is compensated by higher unit payments, if SBG does not occur, then OPG benefits from both a higher unit payment and greater sales of energy at a higher price. However, deviations in water conditions can compensate either OPG or consumers depending on the nature of the deviation of actual water conditions from forecast water conditions.

Board staff submits that deviations from forecast production that are the result of SBG should be treated in a manner that is similar to deviations in water conditions. Specifically, Board staff proposes that:

- Accounting for SBG through adjustments to the hydroelectric production forecasts be disallowed;

[193] Tr. Vol. 1, p74-76
[194] Issue 5.1, ExhL/Tab5/Sch24

- OPG account for SBG on a *post facto* basis by recording and accumulating actual SBG reductions that are either the results of action ordered by the IESO or actions taken on its own initiative;
- OPG accumulate these SBG-based production losses in a deferral account; and,
- OPG corroborate the specific SBG loss claims through reference to IESO orders (if applicable), general market conditions (total demand, total baseload supply) and audited production reports from the SBG-affected generation units that demonstrate deviations from near-time trend production that is contemporaneous with SBG market conditions.

Board staff proposes that OPG submit accounting records for the SBG deferral account and should support any balance brought forth for disposition with the Audited Financial Statements, as part of its pre-filed evidence in its next application to the Board. OPG may propose including the financial losses from SBG as an adjustment to its estimated revenue requirement.

7.2 Nuclear Production Forecast

OPG has submitted a nuclear production forecast as part of their pre-filled evidence. The forecast includes an exogenous negative adjustment ("forecast for major unforeseen events") to forecast production levels of 2 TWh in both 2011 and 2012. This adjustment is a new element, absent from OPG's previous application (EB-2007-0905), and is not a standard industry practice. OPG is unaware if any other nuclear utility forecasts "unforeseen events".[195]

7.2.1 Methodology

OPG's nuclear production forecast is based on assuming full capacity factor production based on the nameplate generation capacity of individual nuclear units. This full capacity production is then adjusted for unforced, scheduled outages (for maintenance, inspection and retrofitting) and an allowance for forced outages (for emergency repairs, unanticipated events and regulatory changes). Outages are usually defined as lost production days per specific reactor unit.

[195] Issue 5.2, ExhL/Tab1/Sch40

OPG has a very detailed maintenance schedule for its nuclear units based on a three year rolling schedule. This schedule includes detailed estimates of the duration of scheduled maintenance and contingencies for unexpected delays. OPG's forecast methodology is consistent with standard practice in the worldwide nuclear generation industry.

OPG has also included a *post facto* forecast adjustment for "unforeseen events". Based on analysis of forced outages that were the result of unforeseen events in the 2005-08 period, OPG has reduced the nuclear production forecast by 2.0 TWh per year in the test period. Examples of unforeseen events in the 2005-08 period include feeder (tube) thinning, resin release, an inter-station transfer bus issue and calandria tube deterioration.

7.2.2 Major Unforeseen Events

In its pre-filed evidence, OPG presented a nuclear production forecast showing forecast total nuclear production of 48.9 TWh and 50.0 TWh for 2011 and 2012, respectively. This forecast included an adjustment for the impact of "unforeseen events" of 2 TWh per year.[196] OPG values nuclear production on a net revenue basis (minus fuel costs) at $50M per TWh.[197] In cross examination, OPG agreed that the revenue deficiency impact of the forecast for "unforeseen events" is a cumulative $200M over two years.[198]

Cross examination further revealed that OPG was unable to discern if allowing production forecast adjustments for "unforeseen events" was standard practice in other nuclear regulatory proceedings in other jurisdictions.[199]

In addition, pre-filed evidence and cross examination shows that OPG does not include the 2 TWh reductions in projections of nuclear output in its business plan for 2010-14, approved by OPG's Board of Directors on November 19, 2009.[200,201] Testimony revealed that OPG retains the higher production numbers as "stretch targets" for its

[196] ExhE2/Tab1/Sch2, Table 1c
[197] Issue 5.2, ExhL/Tab5/Sch25
[198] Tr. Vol. 6, p80
[199] Ibid., p81
[200] Ibid., p81-84
[201] ExhF2/Tab1/Sch1, Attachment 1, p9

nuclear division to drive productivity improvements and to benchmark incentive awards for employees.[202]

The events that OPG categorizes as "unforeseen" (and which can only be identified after the fact of their occurrence) were challenged in cross examination as events that were the result of design issues or inadequate monitoring of material conditions and not "acts of God" or similar events.[203]

In addition, the decision to spread the production impact of unforeseen events across total nuclear production instead of assigning specific impacts to each nuclear station was cited in cross examination as a reason for understating the costs of production of Pickering "A" and biasing corporate decisions on refurbishment and capital investment. This bias would have an impact on capital investment schedules and the forecast revenue requirement.[204]

7.2.3 Board Staff Proposal for Nuclear Production and "Unforeseen Events" Forecast

Board staff notes that the nuclear production forecast in the application has a significant, and material deviation from the production forecast in the business plan for nuclear production approved by OPG's Board of Directors. This material difference, amounting to a cumulative $200M of revenue, is the direct result of including a forecast for the impact of "unforeseen events" on nuclear production.

Board staff also notes that the impact of a forecast for unforeseen events, while analogous to including the impact of SBG on the hydroelectric production forecast, is not identical to the SBG treatment. Board staff asserts that SBG conditions are most likely the result of general market conditions and events that are outside the operational and managerial control of OPG, i.e., they are truly exogenous events. Whereas, there is some doubt as to whether the unforeseen events affecting the nuclear production forecast are truly exogenous events or the result of cumulative, measurable and discoverable effects of design issues, construction faults and, operational and maintenance deficiencies.

[202] Tr. Vol. 6, p82
[203] Tr. Vol. 6, p108-111
[204] Tr. Vol. 6, p112-117

In cross examination, Energy Probe suggested that it was more appropriate to allocate major unforeseen events to the station most likely to experience the events, i.e. Pickering. Board staff notes that the impact on payment levels of biasing capital investment and refurbishment investment decisions because of the assignment of the 2 TWh adjustments on a corporate instead of a station-specific basis is dwarfed by the immediate impact of a $200 M deficiency in revenue if these adjustments are allowed.

Therefore, because of the above noted considerations, Board staff submits that the 2 TWh per year adjustment from unforeseen events should be rejected by the Board. Board staff submits that the approved nuclear production forecast for 2011 and 2012 should be 50.9 TWh and 52.0 TWh, respectively.

8. DESIGN OF PAYMENT AMOUNTS

8.1 Hydroelectric Incentive Mechanism

The existing Hydroelectric Incentive Mechanism ("HIM") has resulted in certain, and quantifiable, financial benefits to OPG that are the outcome of shifting energy sales from regulated payment settlement to market-based pricing. The benefits that OPG claims that consumers realize from the HIM are uncertain, difficult to quantify and highly speculative.

8.1.1 Background

In 2004, an incentive mechanism for OPG's designated hydroelectric generation was established by regulation. This mechanism was based on an hourly production threshold of 1,900 MWh. Production beyond the threshold could be sold in the wholesale market at market prices instead of receiving the regulated payment. In its previous application (EB-2007-0905), OPG proposed a revised incentive that was based on variable thresholds derived from actual monthly production. OPG argued that an incentive mechanism that was based on market conditions was superior to a fixed threshold. The Board granted OPG's request in its decision.

OPG maintains that it needs this incentive to encourage efficient and coordinated operation of the Niagara Falls generating stations, including the pump generating station ("PGS"). The incentive is designed to shift generation from off-peak hours to on-peak hours with financial benefits to OPG and system cost and pricing benefits flowing to consumers.

In EB-2007-0905, OPG forecast that this incentive would result in $12 M of additional revenues for OPG in 2009. Actual revenues in 2009 were $23.2 M, because of larger than expected price spreads between on-peak and off-peak prices, the result of off-peak prices falling much faster than on-peak prices, and greater-than-forecast shifting of energy to the PGS facility. OPG forecasts incremental incentive revenues of $13.3 M in 2011 and $16.3 M in 2012 because price spreads are expected to decrease compared to 2009.

In the current application, OPG's pre-filed evidence and projections from other documents filed in this proceeding shows the following actual and projected revenues from the HIM.

HIM Revenues ($M.)

	2009*	2010**	2011*	2012*
Projected/Forecast	$12.0	$8.0	$13.3	$16.3
Actual	$23.2	$11.0***		

*Pre-filed evidence (EB-2010-0008)
** Undertaking J1.2 based on OPG's 2010-14 business plan
*** End August 2010; Transcript, vol. 1, p.81

In the pre-filed evidence, OPG gave two reasons for the better-than-forecast revenue for 2009:

- more energy was shifted (and sold) from off-peak to on-peak hours; OPG forecast 783 GWh of production above the hourly volume at Niagara; actual production was 25% greater at 986 GWh; and,
- actual differences between average off-peak and average on-peak market prices were higher than expected, largely because off-peak market prices fell at a greater rate than on-peak prices, however, actual average market prices were much lower

than forecast ($29.5/MWh vs. $44/MWh). The actual market price spread was $14.8/MWh, $0.7/MWh greater than forecast.[205]

OPG claims that consumers benefit from reduced average market prices when energy production is shifted from off-peak to peak periods. OPG claims that these lower market prices reduce total energy costs for consumers and estimated that the use of PGS via the HIM reduced average market prices by $1.14/MWh.[206] However, cross examination revealed that this estimate was unsupported by any calculations in the pre-filed evidence and was subject to uncertainty because of lack of information about how other, non-OPG market participants respond to changes in market price levels.[207]

Cross examination also established that because a high percentage of total energy is sold under fixed price contracts, the level of market prices is largely irrelevant to the total cost for electricity that consumers pay.[208]

8.1.2 Board Staff Submission for HIM Revenues

Board staff notes that at the time that the current HIM was proposed, market pricing for electricity was more relevant to the level of actual costs for energy that consumers paid. Subsequent policy developments that have extended contract pricing to greater proportions of total energy supplied have made the market price largely irrelevant in establishing the level of consumers' electricity costs.

On the other hand, the HIM allows OPG to shift energy sales at the regulated price to sales at a higher market price with no risk of global adjustment credits for consumers. The HIM is a significant and certain source of increased revenue for OPG. Benefits to consumers are less certain and highly dependent on broad-based assumptions about market dynamics that are difficult to quantify and prove.

At the time that the policy was announced to set prices for output from certain "designated" OPG generating facilities, one of the reasons cited was that OPG was not

[205] ExhE1/Tab2/Sch1/p3
[206] ExhE1/Tab2/Sch1/p2
[207] Ibid.
[208] Tr., Vol. 1, p84-86

earning sufficient revenues to service its debt obligations.[209] As a result, OPG's financial condition and rating were deteriorating, jeopardizing debt service and retirement and increasing the potential for taxpayers to assume OPG's financial obligations.[210] Prior to the Board assuming responsibility for setting payment levels, revenue requirements were established with a 5% rate of return on equity. In accordance with section 78.1 of the Act and O.Reg. 53/05, the Board examines OPG's revenue requirements and sets payments that would be sufficient to cover costs and provide a fair return to the shareholder.

Board staff agrees with the general concept that shifting production from "low value" (low market price) periods to "high value" (high market price) periods is a desired outcome but questions whether OPG needs as rich an incentive, with as certain an outcome, as the current HIM confers on OPG. Board staff accepts the need for some limited incentives to encourage OPG to operate its combined Niagara facilities in an economically efficient manner.

Therefore, Board staff recommends that the HIM be modified to ensure that consumers benefit from OPG's HIM inspired actions. Board staff proposes the following:

- OPG be required to file with its next cost of service application a firm forecast of test year revenues expected from the HIM and a detailed explanation of the forecast methodology; this forecast will be subject to Board examination and approval as part of the application proceeding;
- OPG be required to establish an HIM revenue account that accumulates (on an accounting basis) actual revenues realized from HIM sales;
- HIM accumulated revenues for the test years of the current application are to be shared with consumers via future revenue requirement reductions on the following basis:

    - a 25% - 75% (consumers – OPG) sharing of revenues from zero to the forecast HIM revenue;

[209] "Ontario Government Introduces Fair And Stable Prices For Electricity From Ontario Power Generation", backgrounder, Feb. 23, 2005.

[210] "Ontario Government Introduces Fair And Stable Prices For Electricity From Ontario Power Generation", backgrounder, Feb. 23, 2005.

- a 50% - 50% (consumers – OPG) sharing of revenues from the forecast level to 150% above forecast level ;
- a 25% - 75% (consumers – OPG) sharing of revenues from 150% above forecast level to 200% above forecast level; and,
- OPG retains all revenues above 200% of the forecasted revenue level.

Board staff suggests that the ability of the Board to examine and approve OPG's forecast of HIM revenues, and the forecast methodology, is sufficient protection from OPG deliberately submitting a low forecast. Furthermore, Board staff submits that the gradated revenue sharing schedule will offer OPG sufficient incentive to exploit economic and operationally sound use of the PGS to benefit its shareholder while ensuring consumers realize a certain, revenue-based benefit from OPG's actions.

Furthermore, Board staff observes that the PGS can be a useful tool for avoiding "spilling water" when SBG conditions prevail. However, responding to SBG conditions may make the PGS unavailable for HIM purposes because of the limited capacity of the PGS reservoir. A revenue sharing mechanism will reduce the relative value to OPG of the PGS for HIM operation vis-à-vis responding to potential SBG conditions. All other things being equal, this revised mechanism should increase the likelihood that OPG will use the PGS to reduce water spill during SBG conditions.

9. DEFERRAL AND VARIANCE ACCOUNTS

The following table summarizes OPG's deferral and variance accounts.

		O.Reg. 53/05	Board Decision	End Date
1	Ancillary Service Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts	Yes		
2	Income and Other Taxes Variance Account		EB-2007-0905	
3	Tax Loss Variance Account		EB-2009-0038	Dec 31, 2014

4	Hydroelectric Water Conditions Variance Account	Yes		
5	Hydroelectric Deferral and Variance Over/Under Recovery Variance Account		EB-2009-0174	
6	Nuclear Liability Deferral Account	Yes		
7	Nuclear Development Variance Account	Yes		
8	Capacity Refurbishment Variance Account	Yes		
9	Nuclear Fuel Cost Variance Account		EB-2007-0905	
10	Bruce Lease Net Revenues Variance Account		EB-2007-0905	
11	Nuclear Deferral and Variance Over/under Recovery Variance Account		EB-2009-0174	
12	Interim Period Shortfall (Rider D) Variance Account		EB-2007-0905	Dec 31, 2012
13	Pickering A Return to Service Deferral Account	Yes		Dec 31, 2011
14	Transmission Outages and Restrictions Variance Account	Yes		Dec 31, 2012
15	Interim Period Shortfall (Rider B) Variance Account		EB-2007-0905	Dec 31, 2012

Board staff provides submissions on disposition, the Bruce Lease Net Revenues Variance Account and the two new accounts that OPG has applied for: the IESO Non-Energy Charges Variance Account and the Pension and OPEB Variance Account.

9.1 Balances for disposition and the time period for recovery

OPG indicated in its October 8, 2010 update an amendment to its proposal to clear the deferral and variance account balances as at December 31, 2010, on an actual audited basis rather than a forecast basis. In addition, OPG indicated their external auditors' report would provide additional assurance to the OEB with respect to the accuracy of the balances. This filing is expected in early February 2011.

However, the proposed timing of the filing may occur after the Board's decision. Staff submits that the Board would need to incorporate the updated deferral/variance account balances (2010 actual figures) for which OPG is seeking disposition in the Board's decision. Staff submits that OPG should provide the audited 2010 deferral/ variance account balances, and if necessary in advance of the issuance of its audited financial statements, at the earliest possible time to allow for their inclusion in the Board's decision.

9.2 Bruce Lease Net Revenues Account

The proposed recovery of the large balance in the Bruce Lease Net Revenue Variance Account is not consistent with rate mitigation approaches, which consists of clearing large balances over a longer than "normal" period to mitigate rate impacts. OPG has used this approach for Tax Loss Variance Account and previously, the Pickering A Return to Service Deferral Account.

The Bruce Lease Net Revenues Variance Account 2010 forecast balance of $296.6M (updated on October 8, 2010) is proposed for recovery period over 22 months (March 2011 to December 2012). This is not in line with the Tax Loss Variance Account forecast balance of $492M (updated on October 8, 2010) with a proposed recovery period of 46 months (March 2011 to December 2014). In addition, the Pickering A Return To Service (PARTS) Deferral Account balance of $183.8M was approved for recovery over a 45-month period to December 31, 2011 (EB-2007-0905).

Staff submits that OPG should incorporate rate mitigation consistently to large balances in deferral/variance accounts to allow recovery over a longer period to mitigate rate impacts. OPG should provide a revised deferral/variance accounts nuclear rate rider to reflect the recovery of the Bruce Lease Net Revenue Variance Account balance over 46 months consistent with the recovery period for the Tax Loss Variance Account.

9.3 IESO Non Energy Charges

9.3.1 Background

IESO non-energy charges, a centrally held OM&A cost, are applied to OPG's withdrawals of energy from the IESO grid. In response to undertakings J1.4 and J1.5, it appears that Pickering A and B supply 50% of their own station electricity consumption, and the IESO grid provides the balance. At Darlington, 90% of the station electricity consumption is supplied by the station itself, while the IESO grid provides the balance.

For OPG's regulated facilities, the total withdrawals from the IESO grid are in the order of 1 TWh annually.[211] In 2008, the cost of the IESO non-energy charges to the regulated facilities was $14.9M, while in 2009 the cost was $48.8M. The variance of actual cost versus budget was $(9.7)M and $24.2M in the two years respectively.[212] In cross examination, Board staff asked why OPG's 2010 budget was lower than 2009. The OPG witness agreed that the 2009 results are atypical due to vacuum building outages.[213]

OPG states that the charges associated with the factors that make up the IESO non-energy charges are difficult to forecast, in particular, the Global Adjustment which is the largest non-energy charge. At ExhF4/Tab4/Sch1, OPG notes that the cost of the Global Adjustment was approximately $6/MWh in 2008 and had risen to $31/MWh in 2009.

9.3.2 Request for Variance Account

In the application, OPG states that the IESO non-energy charges have increased dramatically, largely driven by depressed market prices and a corresponding increase in Global Adjustment charges.[214] OPG requests a variance account for the IESO non-energy costs to protect OPG and ratepayers from over or under collection of these charges. The account would record the difference between forecast and actual charges.

The applicant noted in its AIC, filed on November 19, 2010, that the Global Adjustment is subject to more uncertainty with the enactment of O.Reg. 398/10 that will change the

[211] Undertaking J1.4
[212] ExhF4/Tab4/Sch2/Tables 1 and 2
[213] Tr. Vol. 1, p108
[214] ExhH1/Tab3/Sch1/p9

method used to collect the Global Adjustment. OPG states that the impact of the change depends on the behaviour of large volume consumers.

Board staff observes that the variance of actual versus budget for 2008 was approximately $(10)M (i.e. overforecast). Board staff has projected the variance for 2010 on a straight line basis based on the response to undertaking J1.3, and estimate that the variance for 2010 will be approximately $10M (i.e. underforecast). While the variance for 2009 was more significant, it was due in part to the vacuum building outage, and OPG now has data to forecast for the impact of major work programs such as vacuum building outages. Further, staff notes that the budget for IESO non-energy charges for 2008 and 2009 was the same, and is a contributing factor to the 2009 variance.

Staff submits that it would be reasonable for the Board to approve the variance account on the basis that the charges are largely pass through and that there are considerable challenges in forecasting. In cross examination by Board staff, OPG agreed that the forecast of IESO non-energy charges is largely irrelevant if the request for a variance account is accepted. Board staff questioned whether OPG had incentive to reduce the IESO non-energy charges through energy efficiency measures if the variance account was approved.[215] If the Board is inclined to approve the variance account request, staff submits that OPG must demonstrate its efforts to reduce consumption from the IESO grid, particularly at Pickering, in future applications.

The Board considers materiality when reviewing a request to establish deferral and variance accounts. The OPG filing guidelines set out several filing criteria using a threshold of $10M and OPG itself referred to the $10M threshold in cross examination.[216] Accordingly, staff submits that it would not be unreasonable to deny the account on the basis of materiality to OPG, i.e. variance of $10M annually or lower. However, as noted above, staff's estimate of the 2010 variance is based on a straight line assumption, and invites OPG to comment on the assumption and materiality in reply argument.

[215] Tr. Vol. 1, p108-109
[216] Tr. Vol. 15, p46

9.4 Pension and OPEB Costs

9.4.1 Background

In its application, OPG requested that the Board approve forecast accounting pension and other post employment benefit ("OPEB") costs in payment amounts. Further, in an Impact Statement filed September 30, 2010, OPG requested approval for a variance account "to record the **revenue requirement impact** (emphasis added) of differences between forecast and actual pension and OPEB costs".[217] The term "actual" refers to the accounting numbers used in OPG's financial statements, not to the actual amounts paid to retirees or contributed to the defined benefit pension fund. OPEB costs include supplementary pensions that provide pension benefits to certain employees beyond the amounts that can be provided by the defined benefit pension plan. The term "OPEBs" in this submission includes both OPEBs and supplementary pensions.

In the Impact Statement, OPG stated that the difference arising from changes in discount rate assumptions, between the date of the pre-filed evidence and August 2010, results in forecast accounting pension and OPEB cost increases of $251.5 M for the nuclear business and $12.7 M for the regulated hydroelectric business. These total forecast accounting pension and OPEB cost increases of $264.2 M have not been identified by OPG to cause any income tax expense consequences. OPG in its AIC identified the tax effects related to actual cash contributions for pensions and OPEBs[218] and how it would treat differences in cash contributions in the proposed variance account.

9.4.2 Revenue Deficiency and Applicable PILs

If the $264.2 M is considered to be revenue requirement as described by OPG in the Impact Statement, then there may also be significant income tax and tax gross-up implications for the Board to consider. In the income tax calculations, the accounting numbers for pensions and OPEBs are added back (increase) to taxable income and the paid amounts are deducted as allowable expenses. OPG discussed the mechanics in its pre-filed evidence.[219] Using the applicable income tax rates from the application, and considering $264.2 M to be a revenue deficiency, the undisclosed (grossed-up) tax

[217] ExhN/Tab1/Sch1/p3/ln15-19, p4/ln1-5
[218] EB-2010-0008 AIC/p96/ln24 to p97/ln16
[219] ExhF4/Tab2/Sch1/p6/s.3.3.5

impact is approximately $91.6 M[220] for the two test periods. Whatever the actual difference turns out to be as at December 31, 2010 and 2011, the revenue deficiency should be adjusted for the income tax PILs impact. However, if OPG's request to place the revenue deficiency in a variance account is approved, it will defer compensation costs and income tax impacts for the test period 2011-2012 into the future period 2013-2014. Staff submits that there is no reason in this case why a known cost should not be recoverable now as opposed to deferring to a future period.

9.4.3 Cash versus Accounting Based Forecasts

Having argued that deferring portions of the pension and OPEB costs is not appropriate, staff will argue below that the total forecast that should be included in the test year payment amounts should be on a cash basis.

The following table of pension and OPEB costs was compiled by Board staff from OPG's evidence.

[220] Exh.F4/Tab2/Sch.1/Table5/ln31 Income tax rates: for 2011, 26.5%; for 2012, 25.0%. (26.5%+25.0%)/2=25.75% $264.2 M*25.75%/(1-.2575)= $91.6 M

	In $ Millions	Combined Nuclear and Regulated Hydroelectric							
		2005	2006	2007	2008	2009	2010	2011	2012
		Actual	Actual	Actual	Plan	Plan	Budget	Plan	Plan
1	**Pension** costs in application (1) (2)				161.9	141.4	98.8	119.8	170.9
2	Impact Statement (3)							220.8	258.2
3	Accounting pension costs (4) (5)	92.3	172.4	192.1	147.0	53.4			
4	Contributions to Pension Plan (6)			211.3	198.6	213.1	206.1	206.1	206.1
5	**OPEB** costs in application (1) (2)				190.8	195.6	159.6	167.3	175.0
6	Impact Statement (3)							206.4	211.8
7	Accounting OPEB costs (4) (5)	142.4	201.8	192.1	177.8	140.9			
8	OPEB Payments (6)			57.4	63.6	63.5	70.6	75.5	80.8
	Total Pensions & OPEBs								
9	**Pensions - OPEBs in applications (7)**				352.7	337.0	258.4	287.1	345.9
10	Impact Statement (8)							427.2	470.0
11	Accounting costs (9)	234.7	374.2	384.2	324.8	194.3			
12	Contributions and payments (10)			268.7	262.2	276.6	276.7	281.6	286.9

Notes: Board Staff have combined the nuclear and hydroelectric information from the below-referenced exhibits to prepare the table.
(1) 2008-2009 EB-2007-0905 Exh.F3/Tab4/Sch.1/Pages26-27 Chart 6
(2) 2010-2012 Exh.F4/Tab3/Sch.1/Page25
(3) 2010-2012 Exh.N/Tab1/Sch.1/Page3
(4) 2005-2007 EB-2007-0905 Exh.F3/Tab4/Sch.1/Pages26-27 Chart 6
(5) 2008-2009 from 2010-2012 Exh.F4/Tab3/Sch.1/Page25
(6) 2010-2012 Exh.L/Tab1/Sch.085/Page2
(7) Sum of lines 1+5
(8) Sum of lines 2+6
(9) Sum of lines 3+7
(10) Sum of lines 4+8

From the above table, it appears that the actual payments to retirees for OPEBs, and contributions to the pension fund, are far more stable over a multi-year period than the erratic nature of OPG's year-end accounting estimates. This is illustrated in the variability of line 11 in the table compared with line 12.

There is no question that over the long-term OPG must recover its prudently incurred costs, including pension and OPEB costs. Staff submits that forecast actual cash payments for OPEBs and for contributions to the pension fund are a fair representation of the actual costs faced by OPG during the test period.

OPEB accounting estimates are substantially higher than the current payments to retirees, as noted in lines 7 and 8 of the table. The forecast accounting OPEB costs attempt to represent the current discounted costs of what the employees have "earned" in the accounting period. OPG also receives higher income tax PILs in revenue requirement by using the forecast accounting OPEB costs.

If the Board allows OPG to collect the forecast accounting OPEB costs from ratepayers, the ratepayers are actually prepaying these future costs today. OPG is not required to place this "over-collection" in a segregated fund on which it will earn a return. The cash "over-collection" goes into general corporate funds to be used for any purpose OPG deems. Staff submits that the Board should consider a segregated fund to deal with this "over-collection" from ratepayers if the Board continues to allow OPG to include the accounting forecast in revenue requirement.

9.4.4 Variance Account Request

Board staff submits that OPG's request for a variance account should be denied. Below, staff outlines three reasons why the account should be denied.

First, in cross examination on November 2, 2010[221], Board staff asked a witness if OPG had discussed the increased forecast accounting pension and OPEB costs of $264.2 M with its shareholder. Staff referred to a letter approving OPG's 2010-2014 business plan which stated that changes should be discussed in advance with the ministries of Energy and Infrastructure and Finance. [222] The witness stated that the increased accounting pension and OPEB costs had not been discussed with the two ministries. Staff submits that if $264.2M is not material enough to discuss with its shareholder, OPG should not be requesting a variance account.

Second, in the previous proceeding, EB-2007-0905, OPG requested a pension/OPEB variance account to capture the impact of changes in discount rate. The Board denied the request. However, had the Board approved OPG's request for a variance account related to the changes in the discount rate used for pensions and OPEBs in the previous proceeding, EB-2007-0905, the balance at the end of 2009 would have been a

[221] Tr. Vol. 15, p102/ln16 to p104/ln7
[222] Undertaking J9.10, Attachment 1

payable to ratepayers of approximately $171 M.[223] There is insufficient evidence to determine the 2010 number, but assuming that the 2009 amount of $143 M[224] occurs in 2010, the projected balance at the end of 2010 could have been about a $314 M credit back to ratepayers. These numbers can be derived from the costs included in the EB-2007-0905 payment amounts for 2008 and 2009 as shown in the table above by subtracting the actual accounting costs (line 11) from the costs included in the application (line 9).

OPG will not be penalized by the Board denying a new variance account for forecast accounting pension and OPEB costs since the projected variances over the test periods of 2008 through 2012 appear to be a net benefit to OPG; that is, a $314 M prior test period benefit versus $264.2 M forecast cost increase shown in the Impact Statement.

Third, it should be noted that in EB-2008-0272,[225] Hydro One Transmission had a negative variance of only $200,000 in the pension cost differential account that it applied to return to ratepayers. In EB-2010-0002[226], Hydro One Transmission requested to recover a pension variance of $3.1M from ratepayers. Staff submits that variances of such small amounts for large companies like OPG and Hydro One are not material enough to warrant variance account treatment.

9.4.5 Conditions for Approval of Variance Account Request

OPG has asked that the variance account precedents in the Hydro One cases be followed in its application.[227] In the previous proceeding, OPG also referred to a Hydro One account as a precedent. The Board denied the request[228] stating that it has not been the Board's practice to allow accounts of this kind, but that there have been exceptions. A Hydro One Distribution account was established in 2004 for known and material increases in pension costs above the amount included in rates. The Board also noted that a pension account was accepted as part of a settlement agreement in a Hydro One Transmission case.

[223] Sum of: 352.7+337.0 (from line 9) - 324.8-194.3 (from line 11) = 170.6
[224] Sum for 2009 of: 337.0 (from line 9) - 194.3 (from line 11) = 142.7
[225] Decision with Reasons, EB-2008-0272, p55
[226] EB-2010-0002 ExhF1/Tab2/Sch1/p1
[227] Tr. Vol. 15, p98/ln8-14
[228] Decision with Reasons, EB-2007-0905, p127

Staff submits that if the Board is inclined to allow a variance account, the basis of recording variances should be the same as provided for Hydro One. That is, the difference between the forecast cash payments to fund the defined benefit pension plan included in rates, and the actual amounts paid, would be recorded in the variance account. Variances related to OPEBs and excess or supplementary pensions should not be recorded.

9.4.6 Selection of Discount Rates

Discount rates and accounting estimates of pension and OPEB costs vary significantly depending on the assumptions made by management and actuaries at any given point in time.

As noted in the application, OPG has used representative AA corporate bonds to forecast the discount rates.[229] GAAP does not stipulate using only AA corporate bonds to determine the discount rate. In Section 3461 of the Canadian Institute of Chartered Accountants' Handbook at paragraphs .063 to .065, it defines what must be considered in the selection of a discount rate, such as when rates on high-quality corporate bonds are available they are used to determine the discount rate.

Staff suggests that there may be more than one method to determine the discount rate to be used, and the differences could lead to material deviations in the amounts proposed for recovery for pensions and OPEBs. Staff submits that OPG should provide evidence that discusses other alternatives than just AA bond yields in future applications.

10. REPORTING AND RECORD KEEPING REQUIREMENTS

Utilities that are regulated by the Ontario Energy Board file documents both quarterly and annually under Reporting and Record Keeping Requirements ("RRR"). OPG does not yet have specific requirements to file information with the Board on a regular basis.

[229] ExhF4/Tab3/Sch1/p22

During this proceeding, a number of items have been identified which OPG has indicated it can file either quarterly or annually depending on the nature of the information.

OPG filed audited financial statements for the prescribed facilities as part of the current application, as directed by the Board in the last proceeding, EB-2007-0905. OPG believes that these financial statements have limited use, and are expensive and difficult to produce. Further, OPG commented during the hearing that the utility of these financial statements is limited as reflected in how little they were used in the course of the current proceeding.[230]

10.1 Reporting and Records

In response to a Board staff interrogatory[231] and through cross examination,[232] OPG has agreed that it can file many of the documents suggested by Board staff, either quarterly or annually. These documents include:

- Unaudited balances of deferral and variance accounts within 60 days after calendar quarter end.
- The MD&A and financial statements as filed with the OSC within 60 days for the first three quarters, and with 120 days for December year-end statements as long as the OSC requires these documents to be filed.
- Nuclear unit capability factor and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year end as reported in OPG's quarterly and annual MD&A.
- Head count information, similar to the presentation in Exhibit F4, tab 3, schedule 1, chart 1 by April 30th.
- Capital in-service additions and construction work in progress by April 30th. The details would be worked out with Board Staff and OPG would make a proposal.
- An analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business, and a comparison with the regulatory return included in the payment amounts by June 30th of each year. It would be

[230] Tr. Vol. 15, p90-91
[231] Issue 11.1, ExhL/Tab1/Sch149
[232] Tr. Vol. 15, p86-90,p95-96

similar to what is set out in Exhibit C1, tab 1, schedule 1, table 7 for the historical period.

Staff submits that OPG should begin filing the agreed upon documents and reports for the 2010 fiscal year in 2011 according to the identified dates. As noted in the Operating Costs section, OPG should make every effort to file FTE as well as head count information.

10.2 Audited Financial Statements for the Prescribed Facilities

As noted above, OPG's position is that these financial statements have limited use, and are expensive and difficult to produce. In response to Board staff interrogatory #149, OPG stated:

> OPG does not believe that it would be able to provide the requested financial statements by April 30 of each year. In fact, OPG believes that the financial statements for the prescribed facilities, as filed in Ex. A2-T1-S1, Attachment 3, should not be a component of ongoing reporting and record keeping requirements. OPG does not believe that these statements provide helpful information to assess and monitor the performance of OPG's prescribed assets for rate making purposes as discussed below.
>
> In preparing these financial statements in accordance with generally accepted accounting principles ("GAAP"), OPG was required to establish allocation methodologies for certain items that are not relevant for rate making purposes because of differences between regulatory constructs and accounting requirements under GAAP (as noted in Ex. A2-T1-S1, section 3.0).[233]

OPG's corporate financial statements do not provide segment disclosure of the prescribed assets. OPG follows the CICA Handbook requirements for segment disclosure primarily based on OPG's business and management structure.

> MR. REEVE: In answer to part (b) of the question, OPG cannot change its current segment disclosure in its general purpose corporate audited financial statements

[233] Issue 11.1, ExhL/Tab1/Sch149/p2-3

> that are filed with the Ontario Securities Commission, as these statements must be prepared in accordance with Canadian generally accepted accounting principles. In accordance with GAAP, the segmented disclosure must be presented consistent with OPG's management reporting structure, and the current segment disclosure reflects this structure.[234]

OPG also stated that its computer systems are not organized to produce financial reports for the prescribed facilities. OPG referred to Hydro One as an example of a company that has organized its financial systems to produce financial statements for the distribution and transmission segments of the business. However, OPG's "understanding is they [Hydro One] have that capability, just because they have been regulated from the start that way."[235]

Board staff is not certain that any utility when first regulated by the Board can immediately provide the RRR filings in totality. Over time, with systems and procedural changes, regulated utilities have developed the capability of filing the reports with the Board. IT and staff costs associated with these projects are generally recovered as part of revenue requirement.

OPG considered, at a high level, the cost implications of producing annual audited financial statements for the prescribed facilities.

> MR. KOGAN: We have had high-level discussions, and basically that is what I have just summarized to you as has been identified. It will be a significant undertaking to even identify the -- all of the systems that would need to be modified and all of the knock-on cost and effects.[236]

Staff submits that OPG should prepare a report to the Board that would detail the internal costs to develop the capability of producing annual audited financial statements with notes for the prescribed facilities. The report should also contain estimates for external costs such as auditors. OPG should identify which costs can be absorbed under the revenue requirement from this proceeding and which costs would be completely incremental.

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[234] Tr. Technical Conference, p121/ln19-27
[235] Tr. Vol. 15, p92-93
[236] Tr. Vol. 15, p94-95

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The current and previous payment amounts cases were filed as cost of service applications. The Issues List for this case contained the following two issues:

> 12.1 When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?
> 12.2 What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

OPG did not file evidence on this matter, and the resolution of these issues will not be determinative of OPG's prescribed payment amounts for the 2011 and 2012 test period. The Board acknowledged this in Procedural Order No. 3:

> OPG has not filed evidence on this issue. Including this issue would cause serious delays, requiring OPG and perhaps other parties, to develop and file evidence. This may take several months. OPG stated that the IRM methodology should be established in the context of the business environment that OPG's prescribed facilities will face over the next five years. This context is not considered in the current application, which extends only to the end of 2012.
> …
> The Board has decided to narrow the scope of the IRM related issues. The Board accepts that an IRM framework for OPG will not result from this hearing, and does not wish to trigger the filing of extensive expert evidence, or otherwise see disproportionate amounts of hearing time spent on this issue.
>
> The Board is interested, however, in considering what next steps might be appropriate with respect to OPG and IRM. The Board indicated an interest in this issue in the first OPG payments case, and is interested in exploring the

> issue further in the current case. … The Board expects that these issues can reasonably be accommodated within the current proceeding.[237]

As noted above, there is no prefiled evidence on these issues. The only evidence is in responses to interrogatories and in the technical conference and the oral hearing, specifically in Volume 15 of the transcript (November 2, 2010).

Board staff and intervenors posed a few interrogatories to OPG. In particular, OPG's response to Board staff IR #150 is the main piece of evidence on this case. In particular, in the response to part d) of ExhL/Tab1/Sch150, OPG has documented a possible process for consideration of an incentive regulation plan. Following the decision in this proceeding on OPG's payment amounts for prescribed assets, "OPG would file an application in 2011 setting out its proposal for incentive regulation, including as needed the provision of expert evidence." This would be the subject of a hearing during 2011 where intervenors and Board staff could file evidence on OPG's proposal, and there would be stages for discovery through interrogatories and/or a technical conference. A "short focused hearing would be held to test the incentive regulation proposals that have been put forward". Following argument the Board would issue its decision by the end of 2011, after which OPG would incorporate the Board's decision into an application (to be filed in 2012) for payment amounts post-2012 (i.e. effective January 1, 2013).

In the Technical Conference, OPG acknowledged that its consideration of incentive regulation is still in its infancy and that its proposal in ExhL/Tab1/Sch150 is "aggressive":

> MR. KEIZER: Thank you. Then moving on to the Board Staff Question No. 40.
> MR. BARRETT: Dealing first with part (a), it references the fact that we did not identify stakeholdering as part of our proposed process. Our position would be, once we have a developed process -- proposal, then we think that would be the time to do any stakeholdering around that proposal. We think that is the most efficient way to conduct stakeholdering. And with respect to part (b), which suggests that we might already have developed a proposal, the answer is: No, we have not yet determined a form of incentive regulation.

[237] Decisions and Orders On Confidential Filings and Issues List, and Procedural Order No. 3, EB-2010-0008, July 21, 2010, p24 and 26

> I would characterize our work at this stage as at a fairly preliminary stage. The schedule we proposed is aggressive, and I will acknowledge that, and we are working hard to try and meet it.[238]

Board staff cross examined OPG witness panel 10 on the matter during the oral hearing.[239] OPG again acknowledged that its proposal was aggressive. It was noted that OPG had not done a total factor productivity ("TFP") study, and had not yet commissioned one to be done. OPG has not retained any external experts to assist in the process. OPG also acknowledged that it would have to plan on filing an application in mid-2011 to meet the timeline documented in ExhL/Tab1/Sch150.

Board staff submits that OPG's proposal as documented in ExhL/Tab1/Sch150 is aggressive and, in all probability, unrealistic as OPG notes that it is in the early stages of planning.

Board staff submits that proper development of an incentive regulation mechanism plan is both time and resource intensive. Development of a plan, and consideration in a hearing would take longer than 12 months based on Board staff's experience. A TFP study, or some other form of detailed econometric analysis is a common element to support an IRM plan. While the theory of such types of analyses is straightforward, their application rarely is. There is no "off-the-shelf" TFP analysis that can have the data plugged into it; the approach must be customized for each situation. The collection, verification and analysis of necessary data take time. Typically, the analysis is iterative in nature. There is also qualitative, expert judgment involved in establishing certain assumptions underlying such analyses. As the Board has seen from experiences in developing the first-generation PBR and third-generation IRM plans for electricity distributors, TFP and similar analyses can take several months (e.g. 5 months or more) to prepare.

Board staff also views that the process to develop a suitable IRM rate adjustment plan for OPG's prescribed hydroelectric and nuclear generation assets will be more complicated and take more time to develop and consider. First, OPG is a generation utility, and has many differences and faces different technological and operational risks relative to "wires" (transmission and distribution) companies. It will therefore not be a

[238] Tr. Technical Conference, p125/ln128 to p126/ln16
[239] Tr. Vol.15, p106/ln11 to p111/ln19

simple solution of taking an existing plan and tweaking to fit OPG. If nothing else, the nuclear asset retirement obligation is a major factor which differentiates OPG from transmission and distribution utilities.

Board staff is unaware of precedent IRM plans elsewhere that would be useful as starting points for an IRM plan for OPG. Probably for similar reasons for which OPG's consultant, Ms. McShane, found a paucity of market data for her review of technology-specific cost of capital, there are probably limited generation utilities that have similar nuclear and hydroelectric generation characteristics and that are rate regulated under IRM. An OPG plan will, in Board staff's submission, probably be home-grown in Ontario.

Finally, Board staff submits that the issue of whether there should be technology-specific IRM plans for each of regulated hydroelectric and nuclear generation should be seriously considered. As has been discussed at length in the proceeding, there are numerous and significant differences between regulated hydroelectric and nuclear generation with respect to operational risks and opportunities. Technology is more important for nuclear. The risk of cost overruns has been highlighted as a risk for nuclear generation. Lower operational costs for hydroelectric, once the generation asset has been constructed, have been documented. While this is a beneficial attribute of hydroelectric generation, it also may constrain productivity gains that can be achieved over time. In other words, once the hydroelectric assets are constructed and running, productivity gains that can be expected would be smaller, in part due to the smaller relative size of operational costs for hydroelectric compared to nuclear. There are also existing different incentive mechanisms, such as the hydroelectric incentive mechanism, which might reasonably be integrated into an IRM plan, but apply to only one generation technology.

As noted above, OPG has not begun any intense work to develop an IRM plan. Board staff thus submits that the process and timelines documented in ExhL/Tab1/Sch150 and as elaborated on during the technical conference and under cross-examination, may be unrealistic for full development of a plan in 2011.

It must also be recognized that the development of an IRM plan is only one part, as a separate application would be required to implement the plan through a rate application. IRM applications can be processed on an expedited basis relative to Cost of Service applications, and the Board routinely processes IRM rate applications for electricity distributions in less than five months. However, Board staff expects that an initial IRM implementation for OPG would take longer. As well as being the first for OPG, there may be matters carrying over from the current Cost of Service regime that may need to be addressed in the application.

As a very rough estimate, Board staff submits that, for rates effective January 1, 2013, OPG would probably have to apply by May 2012 for an IRM implementation application. Working backwards, this would mean that the decision on an IRM framework for OPG's prescribed generation assets would have to be issued in early 2012 (e.g., by March 1, 2012). In turn, this may mean that OPG would have to file its IRM framework application no later than mid-2011.

One option could be to have OPG file an application for both the IRM proposal and for the implementation rates for January 1, 2013 in one application. The application would probably have to be filed in about the third quarter of 2011, which would ostensibly give OPG more time to properly prepare its case. The application could be segmented into two aspects: i) the IRM framework; and 2) implementation for January 1, 2013. A separate decision could be issued on the IRM frame work earlier in 2012, with the implementation decision issued in time for new rates effective January 1, 2013. The attractive feature of this approach is that the IRM proposal could be considered along with how it would play out (as proposed) for January 1, 2013 rates. The downside is that this would be a more complicated application, and would take longer and be more burdensome to manage.

A third option would be to allow OPG to apply for prescribed payments for 2013 under a Cost of Service framework, but for a single test year only (i.e. January 1 to December 31, 2013), with the provision that IRM would apply beginning for the 2014 test year. This would allow more time for OPG to develop an IRM proposal and for it to be considered by the Board, over the period of 2011 and 2012. One downside is that the regulatory review of this application could overlap the application in 2012 for 2013 prescribed payments.

Finally, Board staff is concerned with OPG's absence of stakeholdering early in the process. While any suitable IRM plan for OPG will be individualized, and may differ significantly from that of gas or electricity distribution IRM, there is a great deal of knowledge and experience in Ontario, at the Board and with stakeholders. OPG should be encouraged to consult with Board staff and other stakeholders early and extensively in development of any plan.

- All of which is respectfully submitted -