Ontario Energy Board | Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET
Ontario

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

This page is intentionally blank

EB-2010-0008

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

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

BEFORE: Cynthia Chaplin
Presiding Member & Chair

Marika Hare
Member

Cathy Spoel
Member

DECISION WITH REASONS

MARCH 10, 2011

This page is intentionally blank

Table of Contents

Appendices:

1 INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board (the "Board") on May 26, 2010. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's prescribed generation facilities for the test period January 1, 2011 through December 31, 2012, to be effective March 1, 2011. The Board assigned the application file number EB-2010-0008.

OPG also requested that the Board issue an order declaring the current payment amounts interim if the new payment amounts are not implemented by March 1, 2011. By order dated February 17, 2011, the Board declared the current payment amounts interim effective March 1, 2011.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix D of this Decision. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,
> (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or
> (b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* ("O. Reg. 53/05") provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts.

O. Reg. 53/05 affects the setting of payment amounts for the prescribed generation facilities in three principal ways:

1. requiring that OPG establish certain variance and deferral accounts and that the Board ensure recovery of the balance in those accounts subject to certain conditions being met;
2. requiring that the Board ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG; and
3. setting certain financial values that must be accepted by the Board when it makes its first order under section 78.1 of the Act.

The last item was addressed in the first payment amounts proceeding, EB-2007-0905.

O. Reg. 53/05 can be found at Appendix E.

1.2 The Prescribed Generation Facilities

OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of three nuclear generating stations and six hydroelectric generating stations. These facilities produce approximately 48% of Ontario's electricity.

Table 1: Prescribed Generation Facilities

Hydroelectric		Nuclear	
Station	Capacity[1]	Station	Capacity[1]
Sir Adam Beck I	417 MW	Pickering A NGS	1,030 MW
Sir Adam Beck II	1,499 MW	Pickering B NGS	2,064 MW
Sir Adam Beck Pump Generating Station	174 MW	Darlington NGS	3,512 MW
DeCew Falls I	23 MW		
DeCew Falls II	144 MW		
R.H Saunders	1,045 MW		
Total	**3,302 MW**		**6,606 MW**

Note 1: Net in-service capacity
Source: Exh. A1-4-2, Chart 1 and Exh. A1-4-3, Chart 1

OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the Board must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

OPG has entered into a Memorandum of Agreement ("MOA") with its shareholder. This MOA sets out the shared expectations of the shareholder and the company regarding mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The MOA is reproduced in Appendix G.

1.3 Previous Proceedings

The current application is OPG's second cost of service application. The first cost of service application, EB-2007-0905, was filed on November 30, 2007. The Board's decision on the 21 month test period, April 1, 2008 to December 31, 2009, was issued on November 3, 2008.

OPG filed two notices of motion for review and variance seeking to vary the portion of the EB-2007-0905 decision dealing with the treatment of tax losses. The first motion, EB-2008-0380, filed on November 24, 2008, was dismissed. The second motion, EB-2009-0380 was filed on January 28, 2009 and a decision granting the motion was issued on May 11, 2009. This decision is discussed further in Chapter 10.

On June 9, 2009, OPG filed an application for an accounting order regarding deferral and variance accounts approved in EB-2007-0905. As part of the application, OPG informed the Board that it had deferred the filing of its payment amounts application by one year. The decision, under file number EB-2009-0174, which addressed the treatment of deferral and variance accounts for the period after December 31, 2009, was issued on October 6, 2009.

The Board initiated a consultation on the filing guidelines for the current payment amounts application on September 24, 2009. The filing guidelines were issued under file number EB-2009-0331 on November 27, 2009.

1.4 The Application

In advance of its application, OPG held stakeholder information sessions on March 29, 2010 and April 1, 2010. At those sessions, OPG indicated that it would file the 2011-2012 payment amounts application in mid-April. However, on April 15, 2010, OPG advised that the application would be delayed to late May and that OPG was reviewing the application to identify ways to further lessen the impact of its request on ratepayers.

The application was filed on a Canadian GAAP basis on May 26, 2010. The proposed revenue requirement and recovery of deferral and variance accounts, as filed on May 26, 2010, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$ million	Regulated Hydroelectric			Nuclear			Test Period Total
	2011	2012	Test Period	2011	2012	Test Period	
Expenses							
OM&A	$128.2	$125.9	$254.1	$2,021.2	$2,067.9	$4,089.1	$4,343.2
Gross Revenue Charge/Nuclear Fuel	257.1	252.2	509.3	235.6	261.7	497.3	1,006.6
Depreciation and Amortization	65.6	65.0	130.6	235.4	256.4	491.8	622.4
Property and Capital Taxes	-	-	-	16.0	16.6	32.6	32.6
Income Taxes	30.6	27.4	58.0	53.9	75.9	129.8	187.8
Cost of Capital							
Short-term Debt	4.6	6.1	10.7	3.0	4.3	7.3	18.0
Long-term Debt	106.9	105.8	212.7	70.8	74.4	145.2	357.9
Return on Equity	176.1	175.3	351.4	116.6	123.2	239.8	591.2
Adjustment for Lesser of UNL or ARC	-	-	-	85.0	83.1	168.1	168.1
Other Revenue							
Ancillary and Other	44.9	46.2	91.1	32.0	24.0	56.0	147.1
Bruce Revenue Net of Costs	-	-	-	128.1	143.0	271.1	271.1
Revenue Requirement	**$724.2**	**$711.5**	**$1,435.7**	**$2,677.4**	**$2,796.5**	**$5,473.9**	**$6,909.6**
Deferral and Variance Account Recovery	**(39.5)**	**(47.3)**	**(86.8)**	**227.1**	**232.8**	**459.9**	**373.1**

Source: Exh. I1-1-1, Table 1

With some exceptions, OPG proposed that the 2010 year end balances in the deferral and variance accounts be amortized over a 22 month period from March 1, 2011 to December 31, 2012. The major exception to that proposal is the tax loss variance account, which OPG proposed be amortized over a 46 month period, from March 1, 2011 to December 31, 2014, in order to lessen ratepayer impact. To achieve the revenue requirement and disposition of balances in the deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Rate Riders

($ per MWh)	Hydroelectric	Nuclear
Current		
Payment Amount	36.66	52.98
Rate Rider	—	2.00
Total	36.66	54.98
Proposed		
Payment Amount	37.38	55.34
Rate Rider	(2.46)	5.09
Total	34.92	60.43

Source: Exh. A1-2-2 (as filed May 26, 2010)

OPG estimated that if the application was approved as filed, the combined effect of the proposed payment amounts and rate riders would be an increase of 6.2% over the current payment amounts. This would be a 1.7% or $1.86 increase on the monthly total bill for a typical residential consumer consuming 800 kWh per month.

A summary of the approvals that OPG is seeking in the current application is found at Appendix B.

1.5 The Proceeding

Details of the procedural aspects of the proceeding are provided in Appendix A.

The Board issued Procedural Order No. 3 on July 21, 2010, establishing the final issues list for the proceeding. That list is found at Appendix F.

The Board received five letters of comment in response to the notice of application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision and others which are beyond the scope of this proceeding. Although the Board will not address each letter specifically, these comments have been taken into account in the Board's deliberations.

Two parties applied for, and were granted, observer status. Thirteen parties applied for and were granted intervenor status. The following intervenors took an active role in the proceeding: 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").

CME and CCC brought motions seeking production of certain materials. The Board denied the motions in an oral decision on October 4, 2010. A copy of the decision on the motions can be found at Appendix C.

During the proceeding, confidential treatment was granted for a large number of documents. These documents are filed at the Board's offices.

1.6 Board Observations

This Decision addresses a large number of issues. Most of these issues were material in nature; a number were not. Quite a number of very material issues were explored somewhat late in the process; in some cases the arguments themselves contained what could be characterized as evidence. The regulation of OPG is complex. It is imperative that the high priority issues be identified early and explored thoroughly and effectively during the proceeding.

The Board understands that many of the issues pursued by the parties were sizeable in the absolute sense, often involving millions of dollars. However, issues must be prioritized to ensure that the most significant issues, in terms of dollars and/or in terms of principle, are adequately investigated to ensure an appropriate outcome. The Board and the process are best served by the thorough investigation of the highest priority issues.

It is the Board's conclusion that a number of issues which parties pursued vigorously in cross-examination and argument were not of sufficiently high priority in terms of the dollars or the principle involved. The Board's concern is that an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues. This is not intended as a criticism of any of the parties; nor is it an indication that there was insufficient evidence for the Board to render its decision. Rather, these comments are intended to guide the parties as to the Board's expectations for the next proceeding based on our observations of this proceeding.

The Board will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early.

The Board would also observe that at times the analysis was complicated by the fact that data was presented in ways which was not always comparable. The Board expects OPG to present data on a consistent basis so that comparisons are accurate.

1.7 Summary of Board Findings

The Board has adjusted OPG's requested revenue requirement in some areas and has increased the forecast of revenues in some areas. The following list summarizes those adjustments; the details of the findings are contained in the subsequent chapters of this Decision:

- An increase in forecast hydroelectric production, including a provision for increased Gross Revenue Charge and a variance account to capture the effects of Surplus Baseload Generation;
- An increase in forecast revenue from water transactions;
- An increase in forecast nuclear production, including a provision for increased nuclear fuel costs;
- A sharing of the revenues generated from sales of heavy water;
- A provision for increases in Canadian Nuclear Safety Commission costs;
- The removal of CWIP from rate base;
- A reduction in nuclear compensation costs in 2011 and 2012;
- An update for the return on equity, in accordance with the Board's policy; and
- An adjustment to the Hydroelectric Incentive Mechanism.

The following list identifies the studies and reports that the Board has directed OPG to complete in this Decision:

- Benchmarking of Nuclear Performance;
- Nuclear Staffing Benchmark Analysis;

- Review of Nuclear Fuel Procurement Program ;
- Compensation Benchmarking Study; and
- Depreciation Study.

OPG applied for a total revenue requirement of $6,909.6 million and deferral and variance account recovery of $373.1 million for the two-year test period, resulting in an average payment increase of 6.2%. The Board does not yet have all of the data necessary to establish the final revenue requirement because certain calculations remain to be completed by OPG. Based on the data the Board does have, the Board anticipates a small upward adjustment in the payment amounts that is in the range of less than 1%.

2 BUSINESS PLANNING AND BILL IMPACTS

2.1 Business Planning

The application is based on OPG's 2010-2014 business plan. OPG's business planning process is an annual decentralized process, although planning instructions originate from the finance department. The individual business units develop specific strategic and performance objectives and plan work to achieve the objectives. For the nuclear business, the 2010-2014 business plan incorporates "gap-based" and "top-down" business planning approaches. The gap-based business planning approach was introduced as part of the Phase 2 nuclear benchmarking initiative. There is further discussion of this approach later in this Decision.

In response to the financial and economic environment, OPG's business planning guidelines for 2010 required an $85 million reduction in OM&A compared with previously planned levels for that year. The 2010-2014 business plan was approved by the OPG Board of Directors in November 2009 and received shareholder concurrence.

At stakeholder information sessions held in late March and early April 2010, OPG indicated that it would file its application in mid-April. On April 15, 2010, OPG communicated to stakeholders that the timing for the application had been adjusted to late May and that OPG was reviewing its application to identify ways to further lessen the impact of its request on ratepayers. In May 2010, OPG decided to delay the requested implementation date for new payment amounts to March 1, 2011 and extended the proposed recovery period for the tax loss variance account. These changes were reviewed and approved by the OPG Board of Directors.

The PWU submitted that the assumptions in the 2010-2014 business plan are an appropriate basis on which to set payment amounts. The PWU is concerned, however, with the top-down business planning process used for the nuclear business, and the introduction of the gap-based approach using benchmarking results. The PWU stated that the benchmarking comparators were not peers and further stated that the top-down business planning approach is not appropriate given the capital intensive nature of the business, the technical complexity of the CANDU generators and the strict regulatory requirements of the nuclear business.

CME took issue with OPG's statements regarding the $85 million reduction, referring to the OPG press release dated March 29, 2010:

> We deferred our rate application once but we must go to the OEB this year to make a request for an increase in our regulated rates. We continue to look for internal savings on top of the $85 million we've saved to date.

CME argued that OPG did not reduce OM&A as suggested, but rather only reduced the original increase in OPG's 2009-2013 business plan by $85 million. CME described this and other examples (e.g. $260 million work-drive cost savings discussed later in this Decision at Chapter 4) as misleading characterizations of cost increases as cost reductions.

CME submitted that OPG's business planning process is deficient because it fails to consider total electricity price increases and other economic circumstances facing consumers in deriving the budgets and estimates that form the basis of the application. CME observed that, based on a plain reading of OPG's business planning instructions, the Board could conclude that OPG considers economic turmoil and the hardship consumers are facing in its planning process. CME submitted that, based on the testimony of OPG witnesses, one could conclude that OPG was of the view that the Board can only consider budgets, cost estimates and work programs when determining just and reasonable rates and that the economic hardship facing consumers merely set the context for OPG's planning.

CME submitted that the Board would be ignoring the statutory objectives set out in section 1(1)1 of the Act if it accepts OPG's business planning approach. The objective states:

> 1(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

Further, CME referred to the Minister of Energy and Infrastructure's letter of May 5, 2010, to OPG regarding the impact of the recent recession:

> Bearing that in mind, I would request OPG carefully reassess the contents of its rate application prior to filing with the Ontario Energy Board. I would

> like OPG to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming rate application on those items that are essential to the safe and reliable operation of your existing assets and projects already under development.

CME submitted that the evidence in the case reveals that neither the hydroelectric business nor the nuclear business was asked to reassess the contents of their respective business plans, or to identify ways to lessen costs. Based on the testimony of OPG witnesses, CME observed that the Business Planning group concluded that the business plan already addressed the Minister's concerns. CME submitted that OPG's response to the requests of the Minister should be of concern to the Board.

CCC observed that the "Renewed Regulatory Framework for Electricity" announced by the Board on October 27, 2010 is specifically tied to green energy investments. CCC submitted that neither the Board's policy initiative nor the Ontario Clean Energy Benefit, which provides residential consumers with a 10% rebate, absolve OPG from taking total bill impacts into consideration in its planning.

With respect to the obligation of utilities, CCC referred to the Ontario Court of Appeal decision in the Toronto Hydro-Electric System Ltd. ("Toronto Hydro") case. CCC submitted that the principles of the decision apply for all intents and purposes to OPG:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary duty to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[1]

Both CME and CCC submitted that OPG failed to respond appropriately to the Minister's letter of May 5, 2010. CCC submitted that OPG has added to the burden on ratepayers by unnecessarily requesting construction work in progress treatment for the Darlington Refurbishment Project and by not considering a reduction of its return on equity ("ROE"). CME argued that an unregulated market participant would likely make efforts to "hold the line on electricity price increases" in difficult economic

[1] *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, [2010] ONCA 284, para. 50 (Leave to Appeal to Supreme Court of Canada denied).

circumstances. CME submitted that the Board could approve a revenue requirement for OPG that reflects a lower ROE, arguing that a temporary reduction in ROE poses no threat to system safety or reliability. CME referred to the period prior to 2008 when the shareholder acknowledged that it did not need a full equity return to cover its actual costs of capital. At the time, the shareholder used a 5% return on equity to establish the revenue requirement for OPG.

OPG replied that the criticisms of the company's business planning process related to issues that, in OPG's view, have nothing to do with the company. OPG disagreed that it is obliged to consider costs over which it has no control.

With respect to the parties' reference to the Toronto Hydro case, OPG stated that the Board's decision, which was upheld by the Court, was related to concern about under-investment in physical plant and was hence a matter of prudence.

With respect to the Minister's letter of May 5, 2010, OPG replied that senior management had decided to delay the application to consider whether the application could be adjusted well before receiving the letter. OPG admitted that it did not change work plans or budgets in the 2010-2014 business plan, but maintained that this was not necessary "given the care OPG took in containing costs over which it has control during business planning."[2]

Board Findings

OPG has adopted a new planning process in the nuclear business, with an emphasis on top-down planning and a gap-based approach designed to drive significant improvement in OPG's operations. The Board does not share the concerns expressed by PWU in this area. The business planning process used by the nuclear division ("gap-based" and "top-down") has the potential to result in an important paradigm shift in how OPG operates. This shift is important if OPG is to improve operating and cost performance in its nuclear business. The Board sees no evidence to suggest that this change will bring about a reduction in safety or reliability. For reasons explained more fully in the benchmarking section of this Decision, the Board does not agree with PWU that OPG's business is not suitable for benchmarking. The Board notes that OPG's shareholder has called for benchmarking in its Memorandum of Agreement. As noted in several places in this Decision, the Board will assess the results of this change in the planning process and the emphasis on continual improvement in future applications.

[2] Reply Argument, p. 13.

With respect to the Minister's letter of May 5, 2010, the evidence is that OPG had already decided, before the letter was received, to forgo any rate increase for January and February 2011 and to delay the recovery of the tax loss variance account. The first adjustment represents a reduction in impact on ratepayers, but not necessarily a reduction in costs: OPG may choose to absorb the forgone revenues without reducing expenditures; it may defer costs to a later period; and for some of the largest projects (Niagara Tunnel, Pickering B Continued Operations and Darlington Refurbishment) the costs are captured through variance accounts in any event. The second adjustment is no reduction at all, merely a delay. OPG took no further or direct action in response to the Minister's May 5, 2010 letter. The business units were not even requested to consider the matter. The Board finds this response surprising. At a minimum, the Minister's letter indicates that the shareholder believed additional savings were possible. The Board would therefore have expected the company to look for further genuine savings. OPG has described what in its view are substantial reductions already included in the application, for example the plan over plan reduction of $85 million. The Board concludes that while this reduction does represent a genuine step towards cost control, it is an exaggeration to call it "savings". Most consumers would reasonably expect "savings" to mean a reduction over what is currently being paid. This is what the Minister requested and this is what OPG has largely failed to deliver.

The Board agrees that OPG has an obligation to consider the economic climate, including trends in electricity costs and consumers' ability to pay, in its business planning activities. A consideration of all aspects of the business climate is part of appropriate business planning. The Board does not agree, however, that OPG has an *obligation* to adjust its plan in response to the external environment. OPG is correct that it cannot control other aspects of consumers' electricity bills. This larger context is for the Board to consider in setting just and reasonable rates, and in particular, in considering whether OPG's forecast costs are reasonable. (This is discussed further below.) While OPG could certainly have proposed cost reductions in light of the economic climate (for example, a reduced return on equity), its *obligation* is to plan taking account of the requirements of its business and to propose payment amounts which represent recovery of an efficient and reasonable level of costs.

2.2 Bill Impacts

OPG estimated that the proposed payment amounts and riders result in an average increase of 6.2% from current payment amounts and riders. The increase represents an increase of approximately 1.7% or $1.86 on the typical residential customer's bill. OPG noted that the current payment amounts have been in place for almost three years by the time new payment amounts come into effect on March 1, 2011, and accordingly the increase OPG is seeking amounts to approximately 2% per year.

OPG argued, "To the extent other forces impact this bill, it would be both unfair and a legal error to reduce OPG's just and reasonable payment amounts to account for those external affects."[3] OPG further argued that it was entitled to recover all prudently incurred costs, which it described in the following way:

> Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the contrary. Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged.[4]

OPG concluded that total bill impacts should be considered by the Board through the integrated policy framework announced on October 27, 2010 (the Renewed Regulatory Framework).

PWU supported OPG's position. PWU agreed that the Board's statutory objective is to protect the interests of consumers, but pointed out that the Board must also respect the adequacy, reliability and quality of electricity services, as noted in the second statutory objective:

> 2. To promote the economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

PWU submitted that the Board has no authority to consider factors beyond OPG's control, if it finds OPG's costs are just and reasonable. PWU argued that it is inappropriate to consider costs over which the Board has no jurisdiction, such as the Global Adjustment Mechanism and the Harmonized Sales Tax.

PWU also asserted that the cost of generation from the prescribed facilities is among the lowest cost generation available to Ontario consumers. PWU submitted that

[3] Argument in Chief, p. 5.
[4] Reply Argument, p. 9.

maximizing the value of OPG's prescribed facilities will help to mitigate bill increases related to higher priced supply that would replace production from the prescribed facilities. PWU also submitted that the Board needs to consider intergenerational equity and that there is an impact on future ratepayers if work is deferred to mitigate bill impacts for today's ratepayers.

SEC argued that the 6.2% increase masks the true extent of the increases OPG proposed. SEC submitted that the revenue requirement reductions related to the Darlington Refurbishment Project should not be implemented and that additional costs related to pension and other post employment benefits should not be deferred. When these factors and the impact of the tax loss variance account balance are taken into account, SEC concluded that the increase over current payment amounts is 13.1%, a decrease of 4.7% for hydroelectric and an increase of 23.0% for nuclear. OPG responded that SEC's analysis is not an "apples to apples" comparison and noted that even SEC admitted that not all the amounts are directly comparable. OPG argued that SEC had understated the current payment amounts by not accounting for the EB-2008-0038 decision (related to the tax loss variance account), and that SEC overstated the test period payment amounts by including post test period amounts.

CCC and CME submitted that the Board should consider total bill impact in its determination of payment amounts. CCC noted that the government's "2010 Ontario Economic Fiscal Review" stated that electricity prices are expected to rise by 46% over the next five years. CME referred to the evidence that it filed in the proceeding, an analysis by Aegent Energy Advisors, which concluded that total costs for non-residential customers would rise by 47% to 64% over the next five years and that the increase for residential customers would be 38% to 47%.

CME submitted that the Board's statutory objective in section 1(1)1 of the Act demands that total bill impact evidence be considered. CCC argued similarly that the Board is legally obligated to take total bill impact into consideration when determining the payment amounts. CCC referred to the decision of the Supreme Court of Canada in the Northwestern Utilities Ltd. case in which the court stated:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer, on the one hand

> and which, on the other hand, would secure to the company a fair return for the capital invested.[5]

Both CCC and CME noted that the Board recognized the need to consider total bill impact when setting rates in the Board's decision in the Hydro One Networks Inc. ("Hydro One") distribution rates case, EB-2009-0096:

> …the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.[6]

CCC submitted that it does not take issue with allowing OPG a fair return on its capital, but stated that the Board must first determine the prudent and acceptable level of investment and then allow OPG a fair return.

CCC argued that the Board's policy initiative (Renewed Regulatory Framework) and the Ontario Clean Energy Benefit rebate do not relieve the Board of its obligation to consider total bill impact in its determination of payment amounts. Similarly, CME stated that the policy initiative does not relieve the Board from considering CME's evidence on bill impacts. CME reported that the majority of its members are either too large to quality for the Ontario Clean Energy Benefit or too small to qualify for benefits available to large consumers. CME stated that if care is not taken in managing increases in electricity prices, these manufacturers are likely to leave Ontario.

OPG responded that parties seeking reductions to OPG's application are doing so on the basis that aspects of the electricity bill over which OPG has no control are rising. OPG argued that the parties overstate the jurisdiction of the Board and that the arguments are really more in the nature of complaints relating to legislative and policy choices made by the Province.

OPG argued that the decision of the Supreme Court of Canada in the Northwestern Utilities case provided for a fair return to the company for the capital invested. OPG also noted that the Board's objectives include not only the protection of consumer interests but also facilitating a financially viable electricity industry. OPG argued that fair

[5] *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at pp. 192-193. ("Northwestern Utilities")
[6] Decision with Reasons, EB-2009-0096, April 9, 2010, p. 13.

return to a utility is comprised of two legal entitlements: the right to recover all prudently incurred costs and the right to a fair return on invested capital.

With respect to prudently incurred costs, in OPG's view, only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses may be excluded. OPG referred to the prudence standard in the Enbridge Gas Distribution Inc. decision, RP-2001-0032:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.[7]

OPG referred to the Board's decision on Hydro One transmission rates, EB-2008-0272, which was made near the bottom of the economic downturn, and noted that the Board stated that it would be inappropriate to "arbitrarily reduce spending in direct response to the economic downturn."[8]

With respect to the fair return standard, OPG referred to the decision of the Supreme Court of Canada in the Northwestern Utilities case:

> By a fair return is meant that the company will be allowed as a large return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[9]

[7] Decision with Reasons, RP-2001-0032, December 13, 2002, p. 63.
[8] Decision with Reasons, EB-2008-0272, May 28, p. 4.
[9] *Northwestern Utilities*, pp. 192-193.

OPG also cited the Federal Court of Appeal's decision in *TransCanada Pipelines v. National Energy Board*, in which the court agreed that the approved rates will enable the company to earn a fair return and is not influenced by any resulting rate impact on customers.[10] OPG also noted that the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, states that meeting the fair return standard is a legal requirement.

Board Findings

Throughout this Decision the Board has rendered findings on the reasonableness of OPG's forecast costs and revenues, and in some cases on the prudence of expenditures which were in excess of prior forecasts. The Board has made adjustments to OPG's proposals in a number of areas. The overall effect of this Decision is a reduction in the revenue requirement from that originally requested by OPG and lower payment amounts than requested and a reduced bill increase for customers. The detailed calculation of the payment amounts will be done by OPG as part of the process of completing the Payment Amounts Order, but the Board estimates that the increase will be in the order of 1%.

The Board has broad discretion to adopt the mechanisms it judges appropriate in setting just and reasonable rates. This is clearly established in O. Reg. 53/05 and the Act. O. Reg. 53/05 states "the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act" subject to certain rules which are specified in O. Reg. 53/05. Section 78.1 states "the Board may fix such other payment amounts as it finds to be just and reasonable, (a) on application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable…" With these authorities, the Board may take account of a broad suite of factors that affect the company and factors that affect consumers. Both considerations are relevant in determining just and reasonable payment amounts. For example, the Board may consider evidence on economic conditions and factors influencing other aspects of electricity rates. These sorts of factors may well be relevant in terms of deciding the appropriate pacing or level of expenditures. The Board must be satisfied that the rates are just and reasonable and it must consider all evidence that it finds relevant for that purpose. For the current proceeding, the Board finds that evidence regarding the economic situation and the trend in overall electricity costs is a relevant consideration,

[10] (2004), 319 N.R. 172 (FCA).

along with a variety of other factors (such as inflation rates, interest rates, legislation, business needs, benchmarking results).

OPG and PWU would have the Board constrain its consideration of the various spending proposals to a very narrow examination based on the presumption that all proposed expenditures are reasonable unless proved otherwise. In the words of OPG, "Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged." The Board disagrees. When considering forecast costs, the onus is on the company to make its case and to support its claim that the forecast expenditures are reasonable. The company provides a wide spectrum of such evidence, including business cases, trend analysis, benchmarking data, etc. The test is not dishonesty, negligence, or wasteful loss; the test is reasonableness. And in assessing reasonableness, the Board is not constrained to consider only factors pertaining to OPG. The Board has the discretion to find forecast costs unreasonable based on the evidence – and that evidence may be related to the cost/benefit analysis, the impact on ratepayers, comparisons with other entities, or other considerations.

The benefit of a forward test period is that the company has the benefit of the Board's decision in advance regarding the recovery of forecast costs. To the extent costs are disallowed, for example, a forward test period provides the company with the opportunity to adjust its plans accordingly. In other words, there is not necessarily any cost borne by shareholders (unless the company decides to continue to spend at the higher level in any event). Somewhat different considerations will come into play when undertaking an after-the-fact prudence review. In the case of an after-the-fact prudence review, if the Board disallows a cost, it is necessarily borne by the shareholder. There is no opportunity for the company to take action to reduce the cost at that point. For this reason, the Board concludes there is a difference between the two types of examination, with the after-the-fact review being a prudence review conducted in the manner which includes a presumption of prudence.

The Board has considered the overall impact of the various adjustments it has made to the requested amounts and concludes that the resulting new payment amounts are just and reasonable in light of all relevant circumstances. The overall increase is approximately 1%.

3 REGULATED HYDROELECTRIC FACILITIES

3.1 Production Forecast

OPG's historic hydroelectric production and test period hydroelectric production forecast are summarized in the following table.

Table 4: Hydroelectric Production

TWh	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)

Source: Exh. E1-1-2, Table 1

OPG uses computer models to derive water flow and production forecasts for the regulated hydroelectric facilities. OPG states that the models have proven to be 90% accurate and that statistical analysis indicates no bias. The hydroelectric water conditions variance account captures the revenue and cost impact of the difference between forecast and actual water conditions.

Surplus baseload generation ("SBG") occurs when electricity production from baseload facilities exceeds Ontario demand. This situation is in many cases alleviated by spilling water at the Niagara plants. OPG stated that in 2009 SBG was more prevalent than it has been historically and, as a result, OPG forecast significant SBG in the test period whereas in the past no specific provision was made for this factor. SBG was negligible in 2008, and for 2009 it was estimated at 0.6 TWh, of which 0.19 TWh was attributable to the regulated hydroelectric facilities.[11]

The SBG forecast for 2010, 2011 and 2012 is 0.2 TWh, 0.5 TWh, and 0.8 TWh, respectively. OPG's SBG forecast is based on publicly available information related to other market participants and its own market intelligence. Relevant factors include potential curtailment from other generators, exports, expected river flows, timing for re-commissioning of Bruce Nuclear facilities, etc. OPG identified expanded wind

[11] Exh. L-2-19.

generation as the primary driver for this forecast in the test period. The test period SBG forecast has a revenue requirement impact of $32.5 million.[12]

OPG explained that the IESO is responsible for mitigating SBG, but when SBG is anticipated OPG establishes offer prices so that any output reductions are based on market economics and a variety of operational constraints. OPG stated that historically it has used all available hydroelectric storage prior to spilling water, but also noted that its use of the Pump Generating Station ("PGS") is always based on the comparative economics of the pump/generate cycle in terms of the associated market prices.

SBG was the only aspect of the hydroelectric production forecast on which parties provided submissions. The PWU supported the inclusion of SBG in the production forecast. Board staff, AMPCO, CME, CCC, SEC and VECC submitted that SBG should not be included in the production forecast, but proposed that a variance account be used. The primary reason cited was the difficulty in forecasting SBG, and most parties noted that the expected 2010 SBG will be considerably lower than originally forecast. The forecast for 2010 was originally 0.2 TWh, but the year-to-date level (as of October 3, 2010) was only 0.0204 TWh. OPG maintained that this situation was due to lower than normal water flows during periods when SBG had been expected and cautioned that higher SBG was still expected before the end of the year.

OPG acknowledged in its Argument in Chief that a variance account for this factor might be appropriate. Board staff submitted that variations in production due to SBG should be treated in a manner similar to variations in water conditions and that OPG should record SBG production losses (ordered by IESO or of its own initiative) in a deferral account. Other intervenors supported the use of a variance account, including VECC, SEC, AMPCO, CCC, CME and PWU. SEC, supported by AMPCO, submitted that only SBG directed by the IESO should be charged to the account.

CME supported use of the account for tracking purposes but cautioned that it might challenge any amount in the account on the basis that "it is questionable as to whether an utility owner that causes adverse impacts on its own utility [through procurement decisions] can recover the costs of those adverse impacts in regulated rates."[13]

[12] Exh. L-5-24.
[13] CME Argument, para. 174.

In reply, OPG argued that it would be inappropriate to exclude SBG from the forecast as this would be inconsistent with the treatment of other factors which are included in the forecast. OPG went on to argue that if the Board is not prepared to accept OPG's original test period forecast of 1.3 TWh, it should at least accept a forecast of 0.4 TWh, which corresponds to the level in 2009 and the forecast for 2010.

OPG indicated its support for a variance account, but emphasized that it should measure variances from the best forecast of SBG. OPG further submitted that the basis for the account should be a modified version of that proposed by Board staff. OPG proposed that the reconciliation be based on:

> …any IESO order or instructions (if applicable), general market conditions (e.g. total demand, total baseload, total supply) and actual production reports from the SGB-affected generation units that show deviations from production that are contemporaneous with SBG conditions.[14]

OPG maintained that SEC and AMPCO's proposal was unworkable because SBG is not normally managed through IESO directives. OPG also argued that CME's approach would inappropriately penalize those resources within the market that help to mitigate the condition.

Board Findings

The only issue the Board needs to address is the inclusion of SBG in the production forecast and whether a variance account is appropriate.

The evidence is clear that SBG was a significant factor in 2009 and is likely to be so again in 2011 and 2012 with the expected increase in wind generation and the expected return to service of refurbished Bruce Nuclear facilities. The Board, however, does not find that the evidence supports a forecast of 1.3 TWh. This is a significant increase over the 2009 actual and even the 2010 forecast. Added to this is the fact that 2010 is now expected to have much lower SBG. The Board accepts that this is in large part due to lower water levels, but the Board finds that there is insufficient evidence to support a forecast of 1.3 TWh for 2011 and 2012. The Board concludes that rather than setting a forecast, a better approach will be to capture the impacts of all SBG through a variance account, with no allowance built into the forecast. This approach will bring transparency to the level of SBG and will assist in assessing whether OPG has taken adequate steps to mitigate the impact of SBG (which is discussed further below).

[14] Reply Argument, p. 27.

The Board will establish a variance account for SBG, with SBG to be measured on the basis proposed by OPG. The Board will not adopt the proposal of SEC and AMPCO that SBG be limited to instances where the IESO directs OPG to take action. The Board accepts OPG's position and evidence that SBG is currently addressed through market mechanisms as well as IESO orders or instructions. The Board has no evidence regarding the implications of requiring OPG to act only on the basis of IESO directives, but the Board is concerned that such an approach would not allow an adequate consideration of the other factors involved (safety, environmental, water level, economics) which the evidence shows are taken into account in responding to SBG conditions.

The evidence indicates that OPG uses the PGS to mitigate the impact of SBG if the market price spreads are large enough to incent OPG to deploy the PGS. The Board will review the use of PGS for this purpose when reviewing the amounts in the account. This is addressed further in Chapter 11 in the section on the Hydroelectric Incentive Mechanism.

The Board does not need to address at this time the issue raised by CME in relation to considerations which may arise at a future disposition of the account. The Board will review the account balance for prudence prior to determining disposition, as is the Board's normal practice.

3.2 Operating Costs

Historic and test period operating costs for the regulated hydroelectric facilities are summarized in the following table.

Table 5: Operating Costs Summary – Regulated Hydroelectric ($ million)

Cost Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
OM&A:						
Base OM&A	$78.6	$53.9	$61.5	$61.8	$68.7	$62.2
Project OM&A	7.0	14.6	9.1	5.3	9.7	10.0
Allocation of Corporate Costs	21.9	26.3	24.9	25.1	24.8	26.3
Allocation of Centrally Held Costs	16.1	14.6	17.4	20.3	22.9	25.5
Asset Service Fee	2.3	2.5	2.6	2.0	2.1	2.0
Total OM&A	$125.9	$111.8	$115.5	$114.4	$128.2	$125.9
Gross Revenue Charge	$241.8	$253.5	$259.6	$257.2	$257.1	$252.2

Source: Exh. F1-1-1

Base OM&A and project OM&A costs have been stable historically, and the test period forecast represents a small increase over prior years actual spending. Allocated costs are rising; these costs are addressed in Chapter 6.

Gross Revenue Charges ("GRC") are payments made by OPG to the province. These payments are made by owners of hydroelectric facilities under section 92.1 of the *Electricity Act, 1998*. The GRC consists of a property tax component and a water rental component. The latter is determined by O. Reg. 124/02 under the *Electricity Act, 1998* and is a function of energy produced and the rate set by the Provincial Government.

The hydroelectric business uses three main sources for benchmarking: EUCG Inc., Canadian Electrical Association ("CEA") and Navigant Consulting. OPG maintained that the individual stations and the regulated facilities in aggregate perform generally better than EUCG and CEA benchmarks in the areas of availability and reliability. OPG's evidence is that the OM&A unit energy cost benchmarking demonstrates that the regulated hydroelectric facilities are cost competitive. OPG provided the results of the EUCG and Navigant benchmarking in support of its position. While there are differences between stations, the aggregate plant result for OM&A cost for 2008 was in the first quartile in both the EUCG and Navigant benchmarking studies. OPG's expectation is that the rankings will be similar for the test period.

There were no submissions objecting to hydroelectric operating costs except for the OM&A related to the Saunders Visitor Centre. This matter is addressed in the next section. There were no submissions on the regulated hydroelectric benchmarking results presented in the evidence. OPG submitted that the test period OM&A budget is reasonable and should be approved, subject to the Board's findings on compensation and the Visitor Centre.

Board Findings

The Board finds the test period costs to be reasonable. The largest component of the hydroelectric costs is the Gross Revenue Charge, and the Board has no authority with respect to this rate. Given the Board's finding that the production forecast will not be reduced for SBG, the Board will increase the provision for the Gross Revenue Charge by $6.6 million in 2011 and $11.5 million in 2010.[15]

[15] Exh. L-5-24.

The Board further finds that the benchmarking methodology and results are reasonable and notes that they have been accepted without challenge by all parties. This evidence supports the conclusion that the hydroelectric business has achieved an acceptable level of efficiency and that the OM&A costs are reasonable. The OM&A costs are also reasonable in light of the trend in actual spending.

3.3 Capital Expenditures and Rate Base

OPG's forecasted capital expenditures for the regulated hydroelectric facilities total $327.9 million and $235.7 million in 2011 and 2012, respectively. A break-out by major grouping, including historical planned and actual amounts, is set out in the following table.

Table 6: Hydroelectric Capital Expenditures

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Niagara Plant Group	$9.9	$33.6	$24.8	$42.2	$25.6	$36.2	$30.7	$30.9
Niagara Tunnel	63.9	170.6	131.3	346.8	213.5	241.8	288.0	199.0
Saunders GS	10.5	4.6	4.0	6.6	11.9	17.3	9.2	5.8
TOTAL	**$84.3**	**$208.8**	**$160.1**	**$395.6**	**$251.0**	**$295.3**	**$327.9**	**$235.7**

Source: Exh. D1-1-1, Table 1

OPG is seeking approval of regulated hydroelectric in-service additions to rate base of $60.9 million, $42.9 million and $51.5 million for 2010, 2011 and 2012, respectively. OPG submits that its capital spending has been prudent and the in-service additions to rate base should be approved. OPG's historical and proposed rate base for the test period is set out in the following table.

Table 7: Hydroelectric Rate Base

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Total Gross Plant	$4,396.5	$4,433.2	$4,416.8	$4,480.6	$4,438.6	$4,485.0	$4,538.0	$4,585.5
Total Accum. Dep.	507.8	570.2	569.5	633.1	631.2	693.6	756.7	820.2
Total Net Plant	3,888.7	3,857.8	3,847.3	3,847.5	3,807.4	3,791.4	3,781.3	3,765.3
Cash Working Capital	21.8	21.8	23.6	21.8	26.0	23.6	21.5	21.5
Materials & Supplies	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6
Rate Base	**$3,911.1**	**$3,880.2**	**$3,871.5**	**$3,869.9**	**$3,834.0**	**$3,815.7**	**$3,803.4**	**$3,787.4**

Source: Exh. L-1-2, Exh. B2-1-1 Table 1, Exh. B2-2-1 Table 1 and Exh. B2-5-1 Table 1

Intervenors and Board staff made submissions on three specific projects: the Niagara Tunnel Project, the Sir Adam Beck 1 G9 Rehabilitation and the St. Lawrence Power Development Visitor Centre.

PWU submitted that OPG is under investing in hydroelectric assets.

Board Findings

The Board finds that the hydroelectric capital budget for projects coming into service during the test period is reasonable in that it is supported by the business cases. No party objected to this portion of the capital budget.

The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year hydroelectric projects which do not come into service during the test period. Some issues were raised related to the Niagara Tunnel Project and the adequacy of OPG's budget, and those are addressed below.

The Board has also determined that no adjustments to the hydroelectric rate base are warranted. Intervenors raised objections to two specific projects, and those are addressed below.

3.3.1 Niagara Tunnel Project

The OPG Board of Directors approved the Niagara Tunnel Project in 2005. The cost was forecast at $985 million and the in-service date was late 2009. In May 2009, the OPG Board approved a revised cost of $1,600 million and a revised in-service date of December 2013. OPG provided a Business Case Summary for the project, dated May 2009 with its application. OPG plans to spend $288.0 million and $199.0 million on the project in 2011 and 2012, respectively. However, as the project will not come into service until 2013, no expenditures related to this project are included in the rate base proposed for the test period. OPG noted that the expenditures related to the Niagara Tunnel Project will be subject to section 6(2)4 of O. Reg. 53/05, and will be addressed at the time the expenditures are proposed for recovery through a payment amounts application.

The Board determined in Procedural Order No. 3 that it would only make prudence determinations with respect to projects or costs that close to rate base in the test period.[16] As a result, intervenor submissions largely focused on the filing of ongoing reports concerning the Niagara Tunnel Project.

AMPCO submitted that the Board should order OPG to produce an annual monitoring report on the tunnel project that is comparable to the report OPG will produce for the Darlington Refurbishment Project. CCC submitted that the Board should require OPG to provide the Project Execution Plan reports (similar to what was filed in the undertaking response JX2.4) until the project is brought forward for approval. In CCC's view, these reports would assist the Board in the final assessment of the project. CCC noted that OPG intends to regularly review and update the project execution plan, and that this reporting will be provided to the OPG Board of Directors and the shareholder.

SEC observed that there will likely be internal OPG reporting on the tunnel project more frequently than once a year. On this basis, SEC submitted that it would be reasonable for the Board to require a tunnel project status report in June 2011 and June 2012. SEC suggested that if the reports indicated a significant cost overrun the Board could call OPG in for review if it was apparent at the time that OPG would not be filing a payment amounts application in 2013. SEC saw further value in the proposed reporting since the Board, if it were aware of cost over-runs in 2011, could hold a "mini-hearing" on the matter in 2011.

OPG responded that the reporting suggested by the parties would be of limited value because the tunnel is expected to be in service in 2013. OPG further argued that the proposed reporting would add unnecessary regulatory burden and cost. OPG noted that it will make a comprehensive filing on the project in the first quarter of 2012 as part of its next payment amounts application and argued that there is too short a time frame for interim reporting.

OPG also objected to filing updated copies of the Project Execution Plan because the Board does not have the same role as the OPG Board in overseeing and managing the project. OPG submitted that reporting to the Board should be focused on the specific

[16] Procedural Order No. 3, dated July 21, 2010, p. 11 "The Board will retain the current statement of issue 4.2 including the term "appropriate" and the reference to business cases. The Board will only make prudence determinations with respect to projects or costs that close to rate base in the test period. While the Board agrees that it would be appropriate to review other aspects of the capital budgets, the Board expects that this review will be more in the form of a status update. The Board does not intend to make any form of quantitative or qualitative finding with respect to projects and costs which close to rate base in the period after the test period."

information required to efficiently monitor and regulate OPG's prescribed facilities and should not be required just because it is provided to OPG's Board of Directors.

OPG also objected to mid-year reporting for the purposes of allowing the Board to hold a mini-hearing. OPG submitted that there is no legal basis for the Board to assume a quasi-project management role during the course of a major project; nor is it a proper role for the Board. OPG also suggested it would create a conflict with the Board's later duty to determine the prudence of the expenditures.

Board Findings

The Board will not require additional reporting on the status of the Niagara Tunnel Project prior to OPG's next payments case. The Board does not intend to manage the project, nor will it to conduct any sort of intermediate review, or "mini-hearing". The appropriate course of action is for the Board to conduct a thorough prudence review at the time that OPG proposes to add the project to rate base. The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.

3.3.2 Investment in Hydroelectric Assets

PWU submitted that OPG's proposed hydroelectric capital and OM&A budgets are appropriate but minimally so. PWU suggested that its own analysis indicates that the test years are in a period when hydroelectric reinvestment levels should be on the rise given the age of the assets, however investment and rate base levels are declining from 2010 levels. PWU submitted that OPG should be directed to file information on the demographics of the regulated hydroelectric assets. OPG replied that this proposal should be rejected because it would require complex analysis and the value of the analysis has not been demonstrated.

Board Findings

The Board will not direct OPG to perform the asset demographics analysis proposed by PWU. PWU asserted that spending should be increasing based on the age of the assets. Spending, however, is primarily related to the condition of the assets, and while age is a contributing factor to asset condition, it is by no means the only one. However, it is up to OPG to provide the relevant evidence to support its proposed expenditures and to demonstrate that it is making adequate investments to maintain an appropriate level of reliability. The Board notes that there is no evidence that reliability has been compromised by the level of expenditures for the test period.

3.3.3 Sir Adam Beck I G9 Rehabilitation

The G9 rehabilitation project includes replacement of the generator, rehabilitation and upgrade of the turbine, and a new transformer. The evidence indicated that OPG expected to complete the project in December 2010 at a cost of $32.1 million.

AMPCO pointed out that in the previous proceeding, EB-2007-0905, the projected cost was $30 million with an in-service date of 2009. AMPCO submitted that the increase has not been adequately justified and that the rate base addition should be reduced by $1 million.

OPG responded that the project is on schedule and within the budget presented in the business case summary filed in the current application and that AMPCO did not demonstrate that the costs associated with the project were imprudent. OPG pointed out that the information that AMPCO quoted was at the concept stage, and was later updated at the business case summary stage.

Board Findings

The Board finds that AMPCO's proposal to remove $1 million from rate base is unwarranted. The cost overrun is $2 million, or about 7% in relation to the original project budget. The Board finds that the magnitude of this overrun is not sufficient to suggest mismanagement or imprudence.

3.3.4 St. Lawrence Power Development Visitor Centre

The St. Lawrence Power Development Visitor Centre, which opened in August 2010, is adjacent to the R.H. Saunders Generating Station located in the city of Cornwall. OPG's Board approved the project with a budget of $12.6 million in March 2009. OPG described the purpose of the Visitor Centre as providing an important venue for OPG to deliver its hydroelectric communications (e.g., water safety) while improving community and aboriginal support for continued operation of OPG's second largest hydroelectric generating station.

Energy Probe, Board staff, CCC, CME, AMPCO and VECC opposed the inclusion of about $12 million in hydroelectric rate base and about $0.5 million OM&A for the Visitor Centre, for the following reasons:

- It is inappropriate for electricity ratepayers to pay for expenditures and investments whose purpose is to promote OPG's brand and whose main focus appears to be regional tourism and local municipal relations;
- Water safety messaging is a minor element of the centre and the unregulated hydroelectric segments of OPG benefit from the centre but no costs are recovered from these segments;
- There are more effective ways to promote the Waterways Public Safety campaign;
- Although the project is characterized by OPG as sustaining, there is no direct contribution to the production of electricity at the R.H. Saunders Generating Station; and
- OPG's mandate is to provide electricity and not educational and cultural opportunities.

SEC supported the inclusion of the Visitor Centre in OPG's hydroelectric rate base. SEC believes that the wrong question has been asked to assess the appropriateness of the proposed rate base treatment. In SEC's view, the question that should be asked is whether the project is a normal and usual part of the business of generating electricity from the Saunders facility and just good corporate citizenship, not whether the Visitor Centre will produce more electricity at the facility. SEC also stated that the Visitor Centre is virtually entirely about the Saunders facility and therefore any benefit to the unregulated business is incidental.

OPG argued that the parties opposing the inclusion of the Visitor Centre in rate base had too narrow a view of the purpose of the centre and that the views of parties were not reflective of the realities of operating a major power plant in the modern world. OPG likened the Visitor Centre to administration buildings, storage facilities and parking lots, which are accepted as necessary infrastructure even though they do not directly generate electricity. OPG also noted that the aboriginal relations function is included in base OM&A expense and that the Visitor Centre will strengthen the relationship with the Mohawks of Akwesasne. OPG also argued that its position is consistent with the Memorandum of Agreement with its shareholder requiring OPG to operate in accordance with the highest corporate standards in the areas of social responsibility and corporate citizenship. OPG also objected to having some of the cost allocated to its unregulated hydroelectric business as the Visitor Centre focuses on themes local to the Saunders station.

Board Findings

The Board agrees with OPG and SEC that it is reasonable to include the capital cost of the Visitor Centre in rate base for the regulated hydroelectric facilities. The Saunders generating station is a major corporate facility in the Cornwall area, and it is reasonable for the operation of the facility to promote good relations with the surrounding community. The Board also notes that the Visitor Centre was built, in part, to replace the one that OPG was required to close for security reasons. The Board agrees that it would be inappropriate to allocate any of the costs to the non-regulated facilities as the focus is mainly on local issues and the local facility. As the Board is making no reduction to rate base for this item, there will also be no reduction to the associated OM&A costs.

3.4 Other Revenues

OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account – Hydroelectric.

Segregated mode of operation (“SMO”) transactions occur at the Saunders GS. Units at Saunders can be segregated, when pre-arranged, to serve the Hydro Quebec control area. A high voltage DC intertie between Ontario and Quebec began commercial service in 2009 and, as a consequence, SMO revenues have declined. The SMO forecast in the previous case was based on a 3 year historical average. The test period SMO forecast is based on SMO results for the second half of 2009.

Water transactions (“WT”) between OPG and the New York Power Authority allow the two parties to use a portion of the other’s share of water for electricity generation. In 2009, low electricity market prices reduced WT revenues. As in the case of SMO, the WT forecast in the previous case was based on a three-year historical average. OPG has proposed a test period forecast based on the actual net revenues in 2009.

The following table summarizes historic and test period hydroelectric other revenue.

Table 8: Other Revenues – Regulated Hydroelectric ($ million)

Revenue Source	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget (1)	2011 Plan	2012 Plan
Ancillary Services	$35.6	$32.4	$41.2	$33.1	$42.5	$39.1	$38.3	$39.5
Segregated Mode of Operation	4.4	5.0	13.7	6.6	3.6	6.6	1.5	1.6
Water Transactions	4.3	5.2	8.8	6.9	4.9	6.9	5.1	5.2
Total	**$44.3**	**$42.6**	**$63.7**	**$46.6**	**$51.0**	**$52.6**	**$44.9**	**$46.2**

Note 1: The figures for Segregated Mode of Operations and Water Transactions for 2010 are the amounts imputed by the Board for 2009 (EB-2007-0905). They do not reflect the revenues OPG expects to earn in 2010.

Source: Exh. G1-1-2, Table 1

Both CME and VECC submitted that OPG's test year forecasts for SMO and WT should be adjusted. VECC argued that the current Board approved methodology incorporates actual performance over time and provides OPG with an incentive to increase revenues. VECC also noted that in 2008, OPG earned $12.8 million in excess of the forecast amount for SMO and WT. VECC submitted that applying the current Board approved methodology for forecasting SMO and WT would increase other revenue by $13 million. CME also supported retaining the existing forecast methodology. In the alternative, CME submitted that the Board should establish a revenue sharing mechanism that credits 75% of the net revenue to ratepayers, citing similarities to sharing mechanisms in the gas industry.

In reply, OPG noted that it had a net loss for SMO of almost $1 million for the 12 months up to August 2010, and that neither CME nor VECC challenged the impact of the DC intertie or depressed market prices. OPG agreed that a three-year rolling average will eventually reflect OPG's net revenues, but that in the interim OPG will have returned to ratepayers millions of dollars more than it has earned on SMO and WT.

With respect to VECC's observation about 2008 revenue being higher than forecast, OPG replied that a bad forecast is not a justification for using a methodology which OPG considers wrong. OPG stated that there is no evidentiary basis for the revenue sharing mechanism suggested by CME.

OPG concluded that its proposed methodology should be accepted, but that beginning in 2013, it would have no objection to returning to the three-year average methodology.

Board Findings

The Board finds that the forecast test period revenue for ancillary services is appropriate. No party objected to this forecast, and O. Reg. 53/05 requires the use of a variance account to capture the actual results in any event.

In the last proceeding the Board approved a rolling three-year average for the purposes of forecasting SMO and WT, with the variance borne by OPG. The Board finds that this approach provides reasonable results over time as periods of under-performance will be balanced by periods of over-performance. The Board also agrees with VECC that the strength of this approach is that it embeds actual performance while at the same time providing the company with an incentive to increase revenue. For the structure to be effective, however, it must be retained over time. For this reason, the Board is inclined to retain this approach. The exception to this would be in the case where there has been a fundamental or structural change in circumstances which would render a forecast based on historical performance unreasonable. In the current case, the Board concludes that a rolling three-year forecast remains appropriate for WT, but is not appropriate for SMO.

For SMO, the Board concludes that the operation of the DC intertie with Quebec represents a structural change that renders past experience unreliable for purposes of forecasting future performance. For this reason, the Board will accept OPG’s forecast for 2011 and 2012. The Board will revisit this issue in the next proceeding, with the expectation that a return to a rolling average forecast will again become appropriate. The Board notes OPG’s acceptance of this approach.

For WT the Board finds that the revenue forecast should be based on the three-year average for 2007, 2008 and 2009. This results in a revenue forecast of $6 million per year, or an increase of $1.7 million over the proposed level for the test period. OPG argues that this forecast does not adequately reflect the lower market prices of 2009 compared to 2008. The Board disagrees. The nature of a rolling forecast is that it takes into account all recent experience. Further, the Board finds that a year of lower market prices does not represent a structural change; market prices are by their nature variable. The Board concludes that there is no evidence to support a change to the forecasting methodology for WT.

The Board will not adopt the revenue sharing mechanism proposed by CME. The Board concludes that the best balance of benefits to ratepayers and incentives for OPG is under a structure where the revenue requirement includes a forecast based on historical experience and any variance is borne by OPG. This is the approach adopted by the Board in the last proceeding and it remains appropriate.

4 NUCLEAR FACILITIES

4.1 Production Forecast

Historic nuclear production and test period nuclear production forecasts are summarized in the following table.

Table 9: Nuclear Production (TWh)

	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Darlington NGS	27.2	28.9	26.0	27.8	28.9	29.0
Pickering A NGS	3.6	6.4	5.7	6.6	7.4	7.7
Pickering B NGS	13.4	12.9	15.1	13.7	14.6	15.3
Forecast for Major Unforeseen Events	0.0	0.0	0.0	(2.0)	(2.0)	(2.0)
Total	**44.2**	**48.2**	**46.8**	**46.2**	**48.9**	**50.0**

Source: Exh. E2-1-1, Table 1

The production forecast of 48.9 TWh for 2011 and 50.0 TWh for 2012 was part of the 2010-2014 business plan approved by OPG's Board of Directors. This represents a total increase of 3.9 TWh over actual production in 2008 and 2009.

OPG establishes annual production forecasts for the individual nuclear units and an aggregated forecast for each station leading to an overall nuclear production forecast. The annual forecast is equal to the sum of the units' capacity multiplied by the number of hours in the year, less the number of hours for planned outages and forced production loses. The forecasts include allowances for uncertainty at the station level and the fleet level to recognize events which may not be predictable. OPG has forecast improved production performance across its fleet through reduced planned outage days and improvements in the forced loss rate ("FLR"). The FLR is an indicator of performance reliability. It is a measure of the percentage of energy generation during non-planned outage periods that a plant is not capable of supplying to the electrical grid because of forced production losses such as forced outages.

The forecast also includes 2.0 TWh in reduced production in each year for what OPG calls "major unforeseen events" ("MUE"). From 2005 to 2008, OPG's actual annual nuclear production forecast was less than the business plan level by approximately 3.5

TWh on average. OPG explained that the difference was largely due to forced outages and forced extensions to planned outages due to MUE. OPG's analysis indicated that on average more than 2.0 TWh was associated with MUE, and this experience formed the basis of OPG's test period forecast. The revenue requirement impact of the 2.0 TWh of MUE is $200 million in the test period.[17] Although the business plan includes the provision for MUE, OPG has established performance "stretch" targets for the nuclear business which are 2.0 TWh higher.

Most intervenors recommended that the Board deny the 2.0 TWh adjustment related to MUE. Board staff noted that OPG's nuclear division "stretch" target does not include the MUE adjustment. Several parties expressed concern that incentive payments for OPG management would be based on these "stretch" targets, while payment levels would be based on the lower production forecast.

CCC argued that the MUE adjustment had not been justified and noted that OPG's own witness stated, "we expect to get 50.9 [TWh] in 2011 and 52 [TWh] in 2012".[18] CME made similar arguments and took the view that OPG's evidence in support of the adjustment was extremely limited given the magnitude of the financial impact.

AMPCO noted that the 2011-2012 forecast, while higher than 2008-2009 actual, is lower than the 2008-2009 forecast in the prior proceeding. AMPCO submitted that it would be reasonable to expect that forecast production should improve following the vacuum building outages and the investment in performance improvements, including accounting for some additional outage related to the Pickering B Continued Operations project. AMPCO concluded:

> Having invested heavily in performance improvement, with the Board's approval in past 3 years, consumers have a reasonable expectation that forecasted production should improve, not decline relative to the forecast presented in the previous case, as OPG has suggested.[19]

CME also submitted that witness testimony suggests that OPG does not actually expect to suffer the loss for which it is seeking compensation. In CME's view:

[17] Exh. L-5-25.
[18] Tr. Vol. 6, p. 82.
[19] AMPCO Argument, para. 152.

> OPG cannot have it both ways. They cannot say on the one hand that it is more accurate to say that they will hit 48.9 TWh and 50.0 TWh, but then on the other say that they *expect* to actually hit 50.9 TWh and 52 TWh.[20]

In SEC's view, OPG has not presented evidence that past experience is a good predictor of the future. SEC submitted that, on the contrary, OPG has presented a great deal of evidence about programs and initiatives designed to improve future performance and evidence that for other aspects of the forecast the past is not a good predictor of the future.

PWU did not support the exclusion of the 2.0 TWh for MUE because in its view the result would be an unrealistically high production forecast.

OPG replied that no party questioned or contradicted that MUEs have occurred and are likely to occur in the future; nor did any party introduce evidence that OPG had overestimated the impact of MUEs. OPG noted that the MUE adjustment was less than the historical variance between forecast and actual production. OPG further argued that its approach was consistent with the position put forward by Board staff in the previous proceeding.

SEC also submitted that there should be an adjustment to reflect a change in the Darlington FLR from 1.5% to 1.0%. The historical FLR for Darlington is provided in the following table:

Table 11: Darlington Forced Loss Rate

Year	FLR (%)
2005	1.3
2006	3.2
2007	1.1
2008	0.7
2009	1.6
2010[1]	3.5
5 Year Average (2005-2009)	**1.6**

Note 1: Projection based on 8 months of data, Undertaking J6.5
Source: Exh. L12-30

[20] CME Argument, para. 187.

In SEC's view, an FLR of 1.0% is more reasonable because it is the four year average but removes the anomalous FLR of 3.2% in 2006. SEC estimated this would add between $7 million and $10 million to test period revenues. Board staff submitted that the Darlington FLR should be reduced to 1.1% for much the same reasons. OPG responded that the Darlington FLR was not based on historical average, but was based on recent performance and plant material condition, past and future investment to improve reliability and other performance initiatives.

Board Findings

The evidence is clear that the business plan approved by OPG's Board of Directors and upon which the application is based includes the 2.0 TWh adjustment for MUE. It is also clear that the nuclear business plan does not contain this adjustment – a difference which OPG characterizes as a "stretch goal" to go beyond the business plan.

In the words of one OPG witness:

> We are trying to drive our stations towards higher performance in producing generation for the company, as well as for the Province of Ontario. But because we always have these big one-time events that seem to be occurring, it would be inappropriate and inaccurate to submit a forecast without something like this in it.
>
> So that is why we are trying to drive our nuclear organization to better performance, but at the same time want to create a realistic and reliable forecast that the rest of the company and the IESO and everyone can rely upon.[21]

OPG also argued that "it is in the interest of the people of Ontario that OPG provide incentives to its employees [to] maximize production from the nuclear assets owned by the Province".[22] This benefit to the people of Ontario is presumably through greater quantities of available generation and higher revenues to the company if actual production exceeds forecast. However, this benefit is at the direct expense of ratepayers because the forecast (and therefore the payment level) ensures that the company is protected in the event the incentives are completely unsuccessful. Ratepayers would benefit directly from this incentive structure if all or some of the stretch goal was incorporated into the production forecast used for payment setting purposes. And as OPG acknowledges, the stretch goals have to be achievable to be

[21] Tr. Vol. 6, p. 83.
[22] Reply Argument, pp. 76-77.

effective. The testimony establishes that OPG does expect to achieve the higher forecast. The Board concludes a lower level of MUE should be adopted into the forecast because the evidence demonstrates that the target production levels are viewed as achievable and OPG expects to achieve them.

OPG's MUE forecast rests on the premise that because these unforeseen events have happened in the past they will happen again. OPG claims that no reduction in the level of these events can be expected as a result of the various performance improvement initiatives which have been implemented. The Board does not find this position to be substantiated by the evidence. There may well be events which are unforeseen, but the nuclear business plan, the benchmarking efforts, and forecast expenditures are all aligned with enhancing the reliability and *performance* of the nuclear units. While the Board accepts that there may continue to be significant events which have the effect of reducing production, the Board cannot accept the position that the level of these events will be unaffected by the full spectrum of performance improvements established by OPG. The Board further notes that the Memorandum of Agreement between OPG and its shareholder states that, "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." The Board concludes that it is reasonable for ratepayers to be the beneficiaries of improved performance being driven internally and by the shareholder.

The Board concludes that a forecast of 50.4 TWh for 2011 and 51.5 TWh for 2012 should be used for determining the revenue requirement. This incorporates an MUE adjustment of 0.5 TWh per year. The Board finds that this provides adequate recognition of past historic variances due to MUE and the possibility of future similar events, but also incorporates the impact of overall performance improvements, recognizes the expectations of the nuclear business and sets an incentive structure that provides benefits to ratepayers while still providing upside potential for OPG.

Finally, the Board accepts OPG's evidence that the Darlington FLR forecast is not an average of past performance, and finds that, even if an average were an appropriate method, it would not be appropriate to remove the results of 2006 given the similarly high year-to-date FLR for 2010. No adjustment will be made to the Darlington FLR. This issue is also discussed in the next section.

4.2 Nuclear Benchmarking

In the previous proceeding, the Board directed OPG to produce further benchmarking studies in its next application. In response to the Board's direction, OPG retained ScottMadden Inc. to undertake a nuclear benchmarking initiative in conjunction with the development of the 2010-2014 nuclear business plan.

ScottMadden prepared two reports. The Phase 1 report summarized the results of benchmarking OPG's nuclear operational and financial performance against external peers using 19 industry performance metrics. The Phase 2 report established performance improvement targets with the intent of driving OPG's nuclear business closer to top quartile performance. The following table summarizes plant level performance against the 19 industry performance metrics.

Table 10: Plant Level Performance Summary

Metric	Best Quartile*	Median*	Pickering A	Pickering B	Darlington
Safety					
All Injury Rate			0.73 ↑	0.96 ↑	1.04 ↑
2-Year Industrial Safety Accident Rate	0.05	0.09	0.14 ↓	0.07 ↑	0.04 ↑
2-Year Collective Radiation Exposure (man-rem per unit)	62.15	81.84	44.2 ↑	95.81 ↑	72.83 ↑
Airborne Tritium (TBq) Emissions per Unit	48.0	101.0	101.0 ↑	50.7 ↑	40.0 ↓
Fuel Reliability (microcuries per gram)	0.000001	0.000165	0.00059 ↑	0.00159 ↓	0.00025 ↑
2-Year Reactor Trip Rate (# per 7,000 hrs)	0.00	0.33	1.22 ↓	0.26 ↔	0.00 ↔
3-Year Auxiliary Feedwater System Unavailability	0.0014	0.0020	0.0119 ↑	0.0040 ↑	0.0017 ↑
3-Year Emergency AC Power Unavailability	0.0024	0.0076	0.0081 ↓	0.0091 ↑	0.0020 ↔
3-Year High Pressure Safety Injection Unavailability	0.0001	0.0037	0.0012 ↑	0.0001 ↑	0.0001 ↑
Reliability					
WANO NPI (Index)	96.19	62.46	60.84 ↑	60.93 ↔	95.67 ↔
2-Year Forced Loss Rate (%)	0.68	3.79	37.90 ↓	18.19 ↓	0.93 ↑
2-Year Unit Capability Factor (%)	90.97	84.31	56.6 ↓	73.17 ↔	91.99 ↔
2-Year Chemistry Performance Indicator (Index)	1.00	1.01	1.13 ↑	1.25 ↓	1.00 ↔
1-Year Online Elective Maintenance (work orders/unit)	218	278	425 ↑	695 ↑	311 ↑
1-Year Online Corrective Maintenance (work orders/unit)	4	7	14 ↑	28 ↑	11 ↑
Value for Money					
3-Year Total Generating Costs per MWh ($/Net MWh)	28.66	32.31	92.27 ↑	58.68 ↔	30.08 ↔
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)	18.06	21.28	82.62 ↑	50.95 ↔	25.10 ↔
3-Year Fuel Costs per MWh ($/Net MWh)	5.02	5.37	2.64 ↔	2.68 ↔	2.62 ↔
3-Year Capital Costs per MW DER	32.79	46.22	32.07 ↓	32.44 ↑	18.79 ↔

*Panel used for WANO quartile and median data was All COG CANDU

↑ = overall upward trend during reporting period

↓ = overall declining trend during reporting period

↔ = consistent performance during the reporting period

Green = best quartile performance/max NPI points achieved if applicable
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = lowest quartile performance

Source: Exh. F5-1-1, Table 2

The ScottMadden Phase 1 report identified three key metrics (of the 19 benchmarked) and OPG's rank with respect to the comparators:

- World Association of Nuclear Operators Nuclear Performance Index: OPG ranks 17th out of 20
- Unit Capability Factor: OPG ranks 18th out of 20
- Total Generating Cost per MWh: OPG ranks 16th out of 16

The evidence and the testimony of OPG witnesses and Mr. John Sequeira of ScottMadden Inc., addressed the implementation of a gap-based business planning process to drive improvements. OPG has developed initiatives to close performance gaps between it and its industry peers. OPG has implemented a top-down approach to set operational and financial performance targets and generation targets. Under the top-down approach, performance gaps are identified relative to comparators; targets are set by management and communicated down to the business units which are requested to define ways to close the gap. In contrast, under the bottom-up approach, business units develop their business plans which are rolled up to the company level. OPG stated that the top-down business planning is a new commitment that establishes limits on cost and sets expectations for production that directly impact the nuclear payment amounts.

OPG submitted that the benchmarking methodology employed by ScottMadden is reasonable and should be accepted by the Board. In addition, OPG is of the view that the benchmarking results and the targets chosen are appropriate and by adopting the recommendations of ScottMadden in the Phase 2 Report, including top-down gap-based business planning, OPG has responded fully to the Benchmarking Reports and the Board's direction in EB-2007-0905.

OPG further submitted that the combination of the site and support unit initiatives, along with the fleet-wide initiatives, ensured that the 2010 - 2014 business plan operational and financial targets established during the ScottMadden Phase 2 target setting were maintained and/or exceeded.

Board staff, AMPCO, CME, PWU, SEC and VECC filed submissions on the benchmarking initiative and addressed the following areas in some detail:

- Comparators;
- Forced Loss Rate;

- Continuous Improvement
- Radiation Protection Pilot; and
- Staff Level Benchmarking.

<u>Comparators</u>

OPG identified that in selecting all North American nuclear plants as peers, including those using pressurized water reactor (“PWR”) and boiling water reactor (“BWR”) technology, the benchmarking peer group was expanded beyond that used in the benchmarking study that was filed in EB-2007-0905. OPG also believes that there are a number of key drivers such as unit size, single unit versus multi-unit stations, age of reactors and technology differences that assist in explaining relative performance. In regard to technology differences, OPG stated that CANDU technology may result in specific cost disadvantages related to the engineering, operating and maintenance costs as compared to PWR and BWR. Whether the disadvantages exceeded the advantages was a matter of dispute.

PWU submitted that the comparator group chosen by ScottMadden is not comparable to OPG due to the unique technological differences of CANDU and therefore it is inappropriate to employ top-down planning based on a flawed external benchmarking exercise. PWU further argued that benchmarking must focus on cost factors that are within the control of management and, in regard to the ScottMadden report, a deliberate decision was made to not attempt to isolate these costs.

Board staff argued that there is no evidence in this case that the disadvantages of CANDU technology exceed the advantages and therefore the CANDU technology should not be a significant consideration in assessing OPG performance against U.S. reactors. SEC stated that it was logically inconsistent for OPG to argue that its CANDU facilities are inherently more costly to operate while also stating that it is not possible to identify and quantify these costs. SEC submitted that OPG should improve benchmarking by undertaking a study of the major cost differences between CANDU and PWR/BWR facilities.

OPG responded that Board staff understated the difference between CANDU and PWR/BWR reactors. While there are advantages to CANDU including lower fuel cost and online fuelling, there are also disadvantages such as extended outage times and higher costs to address maintenance and inspections associated with fuel handling.

Board staff submitted that it would be useful to supplement the benchmarking by assessing targets for each plant against historical performance to assist the Board with its decision making. SEC submitted that the next phase of benchmarking should remove outliers and include analysis of unit size, age and refurbishment status. CME supported SEC's submission. OPG maintained that it has to balance a number of factors and cost is only one of them.

Forced Loss Rate

The Phase 1 report identified that Darlington's two year FLR average was 0.93%. OPG's target for Darlington FLR is 1.5%. SEC and Board staff submitted that OPG's target, which is based on historical data, should be adjusted to exclude the outlier of 3.2% in 2006. Board staff submitted that the FLR target should be 1.1% while SEC submitted that the FLR should be 1.0%. Board staff further submitted that an FLR exceeding 1.1% does not represent "continuous improvement" and that the Board may wish to consider removing $14 million from the revenue requirement.

In reply, OPG stated that the targets were not based on historical averages, but based on recent performance and plant material condition. OPG also stated neither Board staff nor SEC offered any reason why the actual results for 2006 should be ignored. While 2006 is higher than other recent years, 2008 was considerably lower, and the purpose of averaging is to smooth the impacts of both high and low years. OPG further submitted that Board staff and SEC did not take into account the most recent 2010 forecast of 3.5% (based on eight months of actual data) and, in light of this result, 3.2% cannot be considered an outlier. OPG stated that 1.5% does represent a substantial improvement. The Board decision on FLR is also addressed in the production forecast section in this Decision at section 4.1.

Continuous Improvement

Whether the targets represented continuous improvement was an issue because the Memorandum of Agreement that OPG has with its shareholder, and which is found at Appendix G, states:

> 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.

The Board staff submission questioned whether the Darlington FLR and Total Generating Cost targets represented continuous improvement as referred to in the ScottMadden Phase 2 report and OPG's Memorandum of Agreement, particularly given OPG's ranking in the industry of 16th out of 16 for Total Generating Cost.

OPG replied that Board staff's focus was too narrow. OPG stated that Board staff focused on value for money metrics while there are nineteen benchmarking measures.

Radiation Protection Pilot

In order to demonstrate how detailed top-down staffing analysis can be used to identify and drive staffing reduction, ScottMadden piloted an analysis using OPG's Radiation Protection Function. This involved: (a) identifying initial top-down benchmark targets based upon Electric Utility Cost Group ("EUCG") data and Bruce Power staff levels, (b) defining current OPG activities by position, (c) identifying the FTEs associated with each activity, (d) benchmarking these activities against peer companies, and (e) developing estimates of potential OPG future staff levels. Based on the analysis, ScottMadden recommended a potential reduction of 48 FTEs, comprised of 35 being reassigned and 13 eliminated altogether. OPG responded by reassigning 35 staff and eliminating one FTE.

Board staff submitted that ratepayers should not bear the cost of OPG's choice to retain employee positions that the expert consultant identified were not necessary. CME supported this position. OPG replied that the $2.2 million per year reduction advocated by Board staff fails to recognize that one of the 13 positions was eliminated. OPG also stated that the recommendation was held in abeyance pending further study of Pickering A and B consolidation as well as incremental work associated with the alpha contamination industry issue which arose in the last 6 to 8 months.

Staff Level Benchmarking

Board staff quoted from the Phase 2 report at page 26 in the staff submission,

> 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.

Staff also referred to the Navigant report filed in the previous proceeding which found OPG's 2006 staffing levels to be 12% higher than benchmark. Staff submitted that an updated benchmarking report should be filed with the next application and that the Board should direct OPG to file a similar staffing analysis undertaken by ScottMadden

(Appendix G of the Phase 2 Report). OPG stated it considers Total Generating Cost to be the key metric and that staffing and remuneration are factors that drive cost. OPG argued that it was the company's responsibility to decide what evidence to produce to support its application, and in its view Board staff had not shown why filing the staffing analysis should be directed by the Board.

Board Findings

The Board accepts the benchmarking methodology and finds that the ScottMadden reports were conducted objectively and based on considerable expertise and experience in these types of studies. The evidence demonstrates that benchmarking can be conducted for an entity such as OPG. While there are differences between OPG's circumstances and those of its comparators, the entities can be compared and appropriate conclusions can be drawn. OPG's own shareholder expects such comparisons (as identified in the Memorandum of Agreement), and the Board identified the importance of this type of analysis in the prior payment amounts decision. Benchmarking analysis can assist the Board in assessing the reasonableness of OPG's expenditure proposals.

While suggestions were put forward for improvements in the benchmarking parameters and comparators, there was no clear consensus on whether these changes would improve the quality of the methodology or the study. The Board directs OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application. By keeping the methodology and report format consistent, the Board will be able to identify the progress OPG has made in improving its performance relative to the peer group.

The Board will not direct that OPG conduct a study on the differences between CANDU and PWR/BWR technologies, but as OPG itself acknowledges, it is the company's responsibility to decide what evidence to produce to support its application. OPG may wish to consider whether a study of the major cost differences between CANDU and PWR/BWR would facilitate the review of its application on the issue of cost differences between the various technologies.

The actual results of the benchmarking study show that OPG's performance falls far short of what ratepayers should reasonably expect. On all three key metrics in the Phase 1 report OPG ranked last or very close to last. The Board acknowledges OPG's enthusiasm in adopting the top-down approach to budgeting and the commitment to continual improvement in performance. However, the evidence to date has shown limited results. The Radiation Protection Pilot, the cost consequences of which have been captured in Section 6.1, Compensation, is a case in point. An opportunity for increased efficiency was identified but was not fully implemented. This may be a function of timing in terms of how long it takes to implement changes but is nonetheless evidence that only limited progress has been achieved despite OPG's stated commitment to continual improvement. The Board will direct OPG to conduct an examination of staffing levels as part of its next benchmarking study. As OPG works towards improving its overall cost performance the Board wishes to monitor developments in the area of staffing, as well as compensation and operational performance.

With respect to the targets, the Board has already decided (in the context of the production forecast) not to adjust the Forced Loss Rate forecast. Although the Board accepts the forecast target, there is considerable room for improvement as demonstrated by OPG's historical FLR in the Phase 1 report, and the Board expects to review in the next application the initiatives OPG has taken and intends to take to improve the FLR.

The Board will make no adjustments to the OM&A forecasts directly as a result of this benchmarking work. However, the Board's findings with respect to compensation are based in part on the benchmarking evidence. This is discussed more fully in Chapter 6.

4.3 Nuclear OM&A

The test period OM&A forecast is summarized in the following table.

Table 12: OM&A Summary – Nuclear

$ million	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Base OM&A	$1,204.9	$1,252.4	$1,216.5	$1,187.0	$1,192.3	$1,219.8
Project OM&A	111.6	136.5	143.7	143.8	135.9	132.2
Outage OM&A	215.6	196.1	254.8	284.6	214.8	201.1
Generation Development OM&A	11.8	34.1	79.5	40.5	5.9	4.5
Allocation of Corporate Costs	240.7	237.6	234.5	247.0	249.2	252.3
Allocation of Centrally Held Costs	210.2	132.2	58.8	171.0	199.0	234.3
Asset Service Fee	33.2	28.8	27.2	24.6	24.1	23.7
Total OM&A	$2,027.9	$2,017.7	$2,015.0	$2,098.6	$2,021.2	$2,067.9
Fuel	$113.0	$149.9	$172.6	$201.9	$235.6	$261.7

Source: Exh. F2-1-1 Table 1

Base OM&A is the main cost component for operations and maintenance of the nuclear facilities. Base OM&A also includes labour costs for planned outages and the cost of all forced outages. OPG stated that base OM&A has been reduced significantly noting a decline of $32 million between 2008 actual and 2012 forecast. OPG also stated it has made significant operational and cost improvements which have been demonstrated since the previous application, with cumulative work-driven cost savings of $260 million for the 2010 - 2012 period. In addition, 2012 regular staff levels are forecast to be below 2008 levels by 689, while non-regular staff FTEs will be reduced by 559. OPG noted that these reductions are due to the seven key initiatives that form part of the 2010 - 2014 nuclear business plan and other cost control measures.

Project OM&A includes the costs related to portfolio projects and non-portfolio projects such as Pickering B Continued Operations. OPG stated that there have been significant reductions in portfolio OM&A due to an increased focus on cost control and reprioritization of project work.

Outage OM&A levels depend on the number of specific outages in a given year. The test period outage OM&A is significantly lower than the levels spent in 2009 and 2010, when vacuum building outages were undertaken at Darlington and Pickering.

Board staff and intervenors focused on three issues: Base OM&A, Pickering B Continued Operations and nuclear fuel. These are addressed below.

4.3.1 Base, Project and Outage OM&A

Board staff questioned OPG's assertion that 2012 base OM&A costs are forecast to be below 2008 with cumulative work driven cost savings of $260 million for the 2010-2012 period. Staff noted that OPG only identified adjustments that were in its favour in arriving at the $260 million figure, as only cost increases were included to normalize the results. Board staff also observed that there was OM&A underspending (compared with approved levels) in 2008 and 2009 of $67 million.

Board staff also submitted that it was unable to confirm OPG's FTE reductions evidence, suggesting to Board staff that the reductions were overstated. One of the contributors to this difficulty in confirming FTE reductions is OPG's practice of using headcount for historical periods and FTE for the future test period. Board staff also questioned the appropriateness of using 2008 as a comparator year given the costs and staff vacancies that were deferred from 2007 to 2008 which contributed to a base OM&A increase of $47.5 million from 2007 to 2008.

CME agreed with Board staff that OPG does not appear to have achieved work-driven savings of $260 million and noted that the Board should be particularly concerned by the historical trend of OPG's Base OM&A decreasing in 2009 and 2010, followed by material increases in the test years.

OPG replied that its evidence clearly shows a downward trend from 2008 to 2012 on a normalized basis. OPG maintained that when the 2010-2012 data are properly adjusted, there is a $260 million savings when compared with 2008. OPG replied that it chose 2008 as a comparator year because it was the first year of regulation, and 2008 was not chosen to make the test period forecast appear more favourable.

In reply, OPG presented data from three sources and concluded that the FTE reductions from 2008 to 2012 are 643 and not 443 as stated in the staff submission. OPG noted that the restated FTE reduction of 643 is not much lower than the 689 provided in the application.

SEC submitted that the Darlington OM&A budget should be reduced to meet a non-fuel operating cost of $25.10/MWh, stating there is room to manage staffing. SEC submitted that this would reduce the revenue requirement by $40 million. OPG replied that the interrogatory responses that SEC was relying on were not all presented on the same basis and that other post employment benefits were not included consistently.

SEC submitted that base OM&A should also be reduced by $10 million, or 1% of labour costs, to reflect the difference between the standardized labour rates used for calculating the budget and the actual labour costs. OPG responded that the submission is not consistent with the evidence. OPG referred to testimony to the effect that there will always be a variance with respect to the standard labour costing process.

SEC also submitted that OPG should develop a plan to achieve a non-fuel cost target of $40.00/MWh for Pickering A and B, but did not suggest a specific OM&A reduction for Pickering. AMPCO submitted that the 10% base OM&A disallowance for Pickering A from the previous case did not impair OPG’s ability to operate Pickering A safely and that the costs related to the operation of Pickering A continue to be excessive. AMPCO therefore submitted there should be a further 10% reduction in base OM&A for the test period for Pickering A. OPG replied that AMPCO’s submission has no basis in the evidence and is arbitrary. OPG further argued that it has implemented a more aggressive business planning process, including aggressive targets for Pickering A operation and maintenance costs.

Board Findings

Despite the disagreements amongst the parties as to the extent of OPG's claimed savings to date, the Board concludes that OPG has made progress in controlling costs and the growth of costs, but the benchmarking evidence and compensation evidence demonstrate that further progress is warranted. Rather than selecting specific cost per MWh targets for each of the stations, the Board has focused its attention on compensation costs. Compensation costs are one of the key drivers of OM&A expenditures and hence overall cost performance. That issue is addressed in Chapter 6. The Pickering B Continued Operations project is addressed separately below.

The Board will make no additional adjustments to the forecast Base, Project or Outage OM&A levels, with one exception. In its Impact Statement filed on September 30, 2010, OPG identified a $13 million increase over the test period for Canadian Nuclear Safety Commission ("CNSC") fees. OPG did not request recognition of this increase because it is largely offset by a freeze on management salaries. However, the Board is adjusting the provision for compensation costs in Chapter 6 and is including the impact of the management wage freeze in that adjustment. The Board will therefore allow the increased cost associated with CNSC costs as well.

4.3.2 Pickering B Continued Operations

OPG has proposed a continued operations program to extend the life of the four units at Pickering B from 2014-2016 to 2018-2020. OPG noted the program must be undertaken in the test period or the units will start to close and the potential benefits will be lost. There is also the consideration that OPG does not plan to operate the two units at Pickering A with Pickering B shut down due to significant technical and economic challenges. Therefore extending the service life at Pickering B until 2020 will allow the two Pickering A units to operate until at least 2020.

OPG stated that the project is covered by O. Reg. 53/05 section 6(2)4 as the program will increase output, and OPG has requested variance account treatment. The program includes maintenance to improve plant condition, inspections, some feeder replacement and the fuel channel life cycle management project.

In the project business case, OPG estimated that the project will cost $190.2 million, all of which is OM&A. The test period costs are $92.9 million. However, OPG acknowledged that it had double counted the cost of the fuel channel life management project ($8.8 million), and therefore the forecast is actually $84.1 million. The business case analysis indicated that the project has a net present value of $1.1 billion ($2010). OPG has assigned a medium level of confidence to achieving the expected four years of additional life. Accordingly, OPG's Depreciation Review Committee has not proceeded with approval to extend life for depreciation purposes. PWU and the Society supported OPG's position.

CCC submitted that it would be premature for the Board to approve the project at this time and suggested that the need and economics should be considered within the context of the Ontario Power Authority's ("OPA") long term supply plan which will come before the Board for approval. Energy Probe submitted that it had low confidence in the success and good performance of the project and stated its preference to have the project funded by a private shareholder. In reply, OPG repeated that the work must be undertaken in the test period as otherwise the units will start to close in 2014.

Board staff questioned the costing of the Pickering B Continued Operations project. Outside of the admitted double counting for the fuel channel life management project, staff questioned the range of cost estimates in the public domain of $190.2 million in the application and $300 million in other OPG documents as well as the lack of contingency in the $190.2 million figure. OPG dismissed Board staff's concerns in Reply Argument, stating that, "For some reason Board staff is unable to distinguish between numbers that appear in press releases and sustainability reports and the testimony of the senior OPG executive that is actually accountable for the project." [23] OPG asserted that the cost of $190.2 million is OPG's best estimate.

Board staff also questioned the estimated benefits associated with the project and recommended that OPG provide an independent analysis of the project to support future cost recovery. For example, staff submitted the use of a price of approximately $50/MWh is inappropriate in assessing Pickering relative to replacement generation and that the appropriate figure to use is Total Generating Cost. Staff also questioned the assumed unit capability factors since they were much higher than the actual unit capability factors at the Pickering stations. SEC agreed with Board staff that the

[23] Reply Argument, p. 201.

benefits of the project appear to be over stated. SEC submitted that OPG should curtail further spending until an independent analysis of the benefits is carried out.

OPG argued that no parties provided competing analyses of the benefits. In OPG's view, references to the assumptions used in its analysis were selective and it is clear that the OPA supports the test period expenditures. OPG further submitted that using Total Generating Cost for the benefits analysis should be rejected since it includes costs that will exist notwithstanding the shutdown of Pickering. With respect to unit capability factors, OPG noted that it had performed a sensitivity analysis with varying levels of unit capability factors and the net present value is significantly positive even for the lower end of the range.

Board staff argued that, given the confidence expressed by OPG's witnesses that the project will come in on budget and that no contingency is required, there should be no need to use the capacity refurbishment variance account. If the Board has discretion, staff recommended that the Board restrict the use of the account to those costs that are not routine OM&A activities (i.e., the fuel channel life cycle management project). Staff also noted its concerns that OPG stated it is counting on the variance account to the extent a contingency is required. AMPCO supported the approach proposed by Board staff. OPG maintained that the entire project is clearly within the scope of the account. OPG noted that even work for which there is high confidence can have a variance. Further, if the project comes in under budget, excluding it from the variance account would mean that ratepayers would be denied a credit.

Board Findings

The Board approves $84.1 million in costs for Pickering B Continued Operations in this test period.

In this proceeding, the Board is of the view that its role is limited to determining the following:

- whether the planned spending on the Pickering B Continued Operations in 2011 and 2012 is reasonable based on the business case; and
- whether OPG's decision not to extend the end of life for Pickering B for accounting purposes is reasonable. This issue is addressed in Chapter 8.

The Board will consider spending for years beyond the current test period in OPG's next application, at which time there will be examination of the progress to date and an assessment of project economics and the company's confidence level on the basis of that experience and more current information.

With respect to the planned spending during the test period, the Board has determined that the proposed O&M budget is reasonable, except for the double counting of the fuel channel life cycle management project which will be corrected. The Board is satisfied that the business case substantiates the reasonableness of test period expenditures. However, the Board does have concerns with respect to the analysis. Parties have raised a number of other issues regarding the specifics of the benefits analysis, including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate. The Board expects OPG to address these issues more fully in its next application when the Board considers the next segment of spending, as well as any variance in the account. In seeking to provide the best evidence, OPG should consider seeking an independent assessment by the OPA to be filed with its next application.

With respect to the operation of the variance account, the Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to Pickering B Continued Operations as the project is designed to increase output of a generating facility to which O. Reg. 53/05 applies.

Although this project is to be funded entirely through operating expenditures, it has many similarities with a capital project because O. Reg. 53/05 requires the tracking of any variances through the operation of the capacity refurbishment variance account. In the normal course, for projects funded through operating expenditures, the company would bear the risk of budget variances and would therefore need to manage the costs within its overall revenue envelope. For this project, however, any variances will be captured in the variance account for later prudence determination by the Board. The Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the prudence of any incremental expenditure (over the approved level for the test period) the Board will consider whether OPG might prudently have offset the cost increases through cost reductions or cost deferrals elsewhere in its operations.

4.3.3 Nuclear Fuel

The nuclear fuel cost forecast is $235.6 million for 2011 and $261.7 million for 2012. OPG's current contract mix is 25% indexed contracts (base price plus escalation at time of delivery) and 75% market related contracts (based on market price at time of delivery). OPG's supply contracts are summarized in the following table.

Table 13: Summary of Existing Fuel Contracts (as of Dec 31, 2009)

Contract	Contract Negotiation	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing: MR = Market Related COMB = Combination of MR & Indexed
A	2006 1st half	2007	7 Years	1,462	MR
B	2006 1st half	2010	6 Years	1,154	COMB
C	2006 1st half	2011	5 Years	385	COMB
D	2007 2nd half	2009	9 Years	1,154	COMB

Source: Exh. F2-5-1, Chart 3

OPG asserted that its procurement process balances security of supply with quality and price. Submissions were filed on procurement practices and the nuclear fuel variance account.

Board staff submitted that OPG's fuel procurement strategy needs to be better balanced, with greater emphasis on minimizing cost. Staff pointed to the 30% decline in the market price in uranium in the last two years and noted that OPG's costs have increased 35% in the same period. Staff questioned the prudence of contracting for three to four years of supply within about one year, when OPG stated that only two years of supply is required. Staff also argued that it appears 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 discussed in the application. CCC and CME, SEC and VECC made similar or supporting submissions. CCC and VECC also proposed that there be a third party assessment of OPG's procurement strategy.

OPG responded that the benchmarking results demonstrated that OPG's fuel costs per MWh are lower than any other nuclear operator in the comparator group and that the absolute increase in fuel cost is due to a higher forecast production. OPG further noted that although uranium prices have declined from their peak, they remain substantially above levels seen prior to 2005.

OPG noted that the procurement strategy was reviewed by an external party in 2007 and the report was filed as an undertaking response. OPG maintained that the strategy was approved by the Board in the last proceeding and the only difference now is that parties are using hindsight to suggest that other strategies are appropriate. OPG did express its willingness to undertake another external review of nuclear fuel procurement as long as the funding is maintained in the regulatory affairs budget.

Board staff argued that the current structure of the nuclear fuel variance account does not provide appropriate incentives to minimize nuclear fuel costs and instead provides an incentive for OPG to over-forecast fuel costs. Board staff also noted that when this variance account was established, staff's understanding was that it was to ensure that both consumers and OPG would be held harmless to the extent actual fuel costs differed from the OPG forecast. Nuclear fuel inventory is reflected in rate base as part of working capital. Board staff submitted that OPG would over earn if the Board approves a larger amount for nuclear fuel in working capital than OPG actually uses in the test period. Staff noted that OPG's nuclear fuel inventory was overstated by $27 million during the previous test period and that therefore OPG benefitted financially.

Board staff submitted that the nuclear fuel variance account should be restructured to capture changes in nuclear fuel inventory and to establish a sharing mechanism that is favourable to ratepayers. CCC, CME and SEC supported these recommendations. VECC submitted that the asymmetrical sharing mechanism proposed by Board staff required further analysis. As an alternative to restructuring the existing variance account, VECC proposed that the Board approve a sub-account or separate account for the variance related to fuel inventory in working capital. AMPCO submitted that the account balances should be recalculated since the beginning of the Board's oversight of OPG.

OPG replied that parties provided no evidence to support their claims that the nuclear fuel variance account is a disincentive to cost control. OPG argued that the main driver of the variance was actual production being lower than forecast. OPG maintained that the increase in fuel cost in the test period is related to increases in the price of uranium, processing and higher nuclear production.

OPG argued that Board staff's proposal for a sharing mechanism presents a significant business risk to OPG and is contrary to the creation of just and reasonable rates. OPG also argued that using the existing variance account or creating a new one to address the perceived over-recovery due to nuclear fuel inventory in rate base is too complex to do accurately.

Board Findings

The Board accepts the forecast of fuel costs for 2011 and 2012, and will increase the forecast by $9 million in recognition of the increased production forecast the Board has set.[24]

The Board has determined that a variance account for nuclear fuel costs is not an appropriate way to incent OPG to look for the most efficient portfolio of contracts for nuclear fuel procurement. Nuclear fuel is one of the inputs which OPG must manage, and other than the fact that the Board approved a variance account in the last proceeding, there is no particular reason why this type of cost should be treated as a pass through. The Board has determined that it is more appropriate for the company to bear the risk that the forecast is inaccurate, than for ratepayers to do so.

In the next proceeding, the Board will examine OPG's procurement program to determine whether the company is optimizing its contracting in order to minimize costs to ratepayers. The Board will therefore direct OPG to file an external review as part of its next application.

4.4 Nuclear Capital Expenditures and Rate Base

OPG's forecasted capital expenditures for the nuclear facilities, including the Darlington Refurbishment Project ("DRP"), are $296.9 million in 2011 and $447.4 million in 2012. A break-out, including historical planned amounts and actual expenditures, is set out in the following table.

Table 14: Nuclear Capital Expenditures

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Project Portfolio	$186.4	$172.0	$163.5	$172.0	$159.4	$171.9	$172.0	$172.1
P2/3 Isolation	9.3	17.0	5.7	10.0	14.1	8.8	0.0	0.0
Minor Fixed Assets	11.5	17.8	14.2	16.8	17.0	20.2	19.7	19.5
Pickering B Refurbishment	0.0	0.0	0.0	148.8	0.0	0.0	0.0	0.0
Total Operations	**207.2**	**206.8**	**183.4**	**347.6**	**190.5**	**200.9**	**191.7**	**191.6**
Generation Development*	**0.0**	**0.0**	**0.0**	**0.0**	**1.0**	**72.9**	**105.2**	**255.8**
TOTAL NUCLEAR	**$207.2**	**$206.8**	**$183.4**	**$347.6**	**$191.5**	**$273.8**	**$296.9**	**$447.4**
Note: * Darlington Refurbishment Project								

Source: Exh. D2-1-1, Tables 1 and 2, Exh. D2-1-1, Tables 4a-c

[24] Exh. L-5-25

OPG stated that total project portfolio, including both capital (shown in the table above) and OM&A expenditures, in the test period is $280.3 million in 2011 and $283.2 million in 2012, and that these amounts are consistent with OPG's target annual reinvestment levels of $25 million to $30 million per nuclear unit. The generation development capital reflects the expenditures related to the definition phase of the DRP and the Darlington Campus Master Plan.

In response to the Board's direction in the prior decision, OPG provided a more detailed explanation of the treatment of the Pickering 2/3 Isolation project costs. There were no submissions from parties on this matter.

OPG is seeking approval of a rate base for its nuclear facilities of $4,041.3 million for 2011 and $4,150.8 million for 2012. The proposed amounts reflect $175.5 million and $186.6 million of in-service additions in 2011 and 2012, respectively. OPG's historical and proposed rate base is set out in the following table.

Table 15: Nuclear Rate Base

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Gross Plant at Cost	$4,321.1	$4,525.5	$4,499.0	$4,733.2	$4,679.5	$5,355.3	$5,672.7	$6,047.7
Accumulated Depreciation	1,446.1	1,737.8	1,733.1	2,037.1	2,023.7	2,278.8	2,500.5	2,745.4
Total Net Plant	**2,875.0**	**2,787.7**	**2,765.9**	**2,696.1**	**2,655.8**	**3,076.5**	**3,172.2**	**3,302.3**
Working Capital	16.0	16.0	15.9	16.0	14.3	9.2	4.0	4.0
Fuel	208.7	281.1	266.9	330.1	316.9	357.4	379.8	360.8
Materials & Supplies	400.4	424.4	415.5	441.7	434.4	468.9	485.3	483.7
Total WC/Fuel/M&S	**625.1**	**721.5**	**698.3**	**787.8**	**765.6**	**835.5**	**869.1**	**848.5**
TOTAL NUCLEAR RATE BASE	**$3,500.1**	**$3,509.2**	**$3,464.2**	**$3,483.9**	**$3,421.4**	**$3,912.0**	**$4,041.3**	**$4,150.8**

Source: Exh. B3-3-1 Tables 1 and 2, Exh. B3-4-1 Tables 1 and 2, Exh. L-1-2

OPG's proposed rate base for 2011 and 2012 also includes $125.5 million and $306.0 million respectively for Construction Work in Progress ("CWIP") related to the DRP. The issue of CWIP is addressed in Chapter 5.

The test period revenue requirement does not include any capital or non-capital costs related to new nuclear development. According to OPG, any costs it incurs related to the planning and preparation for new nuclear will be recovered from a new funding mechanism determined by the Province. If no such funding mechanism has been created, then OPG will seek to recover any costs incurred through the Nuclear Development Variance account pursuant to the provisions of O. Reg. 53/05.

No parties objected to any of the proposed capital expenditures except the DRP. This project is discussed in Chapter 5. Parties did raise objections with respect to the level of test year rate base.

Board staff argued that nuclear rate base should be reduced by a total of $128 million in 2011 and $161 million in 2012 for the following four adjustments:

- $100 million should be removed in each of 2011 and 2012 because OPG has not made any changes to prevent a recurrence of the over forecasting of rate base in 2008 and 2009. The historical overstatement of forecast rate base resulted in overearnings of $5.4 million in 2008 and $7.3 million in 2009, not including effects on taxes and depreciation;
- $6 million should be removed in 2011 and $12 million in 2012 to reflect 2010 actual rate base additions being under budget by approximately 10% or $12 million;
- $22 million should be removed in 2011 and $44 million in 2012 because the evidence is that the weld overlay project at Darlington will not proceed until after the test period; and
- $5 million for the partial deferral of the Maintenance Facility at Darlington.

CME, SEC and VECC agreed with Board Staff.

OPG's position was that the $100 million historical overstatement is based on a portion of rate base that ignores un-amortized asset retirement costs ("ARC"), which comprises more than one third of the proposed nuclear rate base. OPG argued that the positive variance in unamortized ARC would offset most of this. OPG also suggested that it had under-recovered depreciation expense in the prior years which would also serve to offset some of the rate base overstatement.

OPG submitted that the Board should apply the same reasoning as found in the Board's Hydro One 2009-2010 transmission rates decision. In that decision, the Board reasoned on the matter of revenue over-collection due to capital underspending that:

> On the other hand, there will be some level of revenue over-collection if the shortfall pertains to projects with in-service dates in the test period. However, the Board accepts that any potential over-collection is short-term in nature because rate base will be corrected in Hydro One's next application. The Board will rely on its usual manner of testing and setting rate base at the next cost of service proceeding and will not order that expenditures be tracked in a variance account.[25]

With respect to projects deferred beyond the test period, OPG's position was that these projects would be replaced with other high priority projects. Board staff questioned the prioritization process and whether this approach was appropriate in times of rising rates. OPG argued that it has a robust process for evaluating proposed capital spending and that Board staff's project-by-project focus is inconsistent with the Board's longstanding approach to reviewing levels of capital spending rather than specific projects. OPG maintained that the level of project spending has been benchmarked and is consistent with other nuclear operators. OPG also pointed out that its project spending has been constant in the period 2007 to 2012 despite increases in material and labour costs. OPG referred to the Board's decision in EB-2005-0001 which stated that it was not the Board's role to micro-manage Enbridge Gas Distribution Inc.'s capital spending plans. OPG also suggested that it is not uncommon for external factors to impact on a utility's ability to undertake a specific project. In these situations, OPG suggested that utilities will advance work from a future year.

AMPCO argued that rate base should be reduced as a result of two projects, the Darlington Change Room project, which was over budget, and the Pickering Cafeteria which was over budget and considerably late. AMPCO argued that the Board should disallow the cost overruns and that additions to rate base should be reduced.

OPG responded that AMPCO had failed to establish that OPG had acted imprudently. OPG also argued that the Post Implementation Report for the Pickering Cafeteria Project, which was relied upon by AMPCO, should not be used as the basis for a finding of imprudence because it is a retrospective review conducted with the benefit of hindsight and not information that could have been known at the time of project execution. With respect to the Darlington Change Room project, OPG pointed out that the final costs were compared with partial release amounts and that only 40% of the engineering had been completed at that stage. OPG argued that a range of +60% to -

[25] Decision with Reasons, EB-2008-0272, May 28, 2009, p. 37.

40% around a project's estimated cost is reasonable, citing the Project Management Institute in support of this proposition.

Board Findings

The Board finds that the proposed capital budget for projects entering service in the test period is reasonable. With the exception of the DRP, the Board is making no finding on the appropriateness of the capital budget for projects entering rate base after the test year. DRP is addressed in Chapter 5.

The Board will not adjust rate base going forward in response to past overstatement of rate base. Looking at total rate base, there is no established trend of over-forecasting. There may be a history of overestimating the level of new plant entering service, but no clear pattern can be discerned at this time which would warrant an adjustment going forward.

The Board notes that while financial accounting requires that ARC be included in gross plant and accumulated depreciation, it would be beneficial and would improve transparency for regulatory purposes if gross plant and accumulated depreciation for ARC were separately identified in the rate base evidence. The Board expects this approach to be taken in the next application.

Several parties argued that there should be an adjustment to capture the impact of the deferral of the weld overlay project and the maintenance facility. As a general proposition, the Board agrees that it should not be reviewing every item in OPG's portfolio, but should be focusing on the larger items, the overall level of capital spending, and whether the budget is reasonable for projects entering rate base in the test period. The Board accepts OPG's evidence that when one project is deferred, there are other projects that can be brought forward. The Board agrees that this is a reasonable approach as much of the work is undertaken by full time staff and contractors which are specifically authorized to work in the nuclear facilities. The Board accepts that OPG cannot easily ramp up or down the overall pace of work on these projects. Although some overall slippage beyond the test period may result, the Board has determined that an adjustment for the deferral of these projects is not warranted given the small amounts involved. In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts in this area. The separate presentation of data related to ARC will assist in this regard.

The Board understands AMPCO's concerns about the overspending on the Pickering cafeteria and on the Darlington change room. However, these projects are very small compared to the overall nuclear division, and the Board is not persuaded that rate base should be reduced as a result of the cost overruns. The Board accepts OPG's evidence that there were unique attributes to these projects being built at a nuclear plant.

The Board is, however, concerned about OPG's argument that a range of +60% to -40% around a capital project's estimated cost is reasonable. This may be acceptable for relatively small projects which do not warrant a large investment in upfront detailed costing or where the variations on a portfolio basis are smaller. However, the Board does not consider the range acceptable for larger projects because it suggests a lack of adequate cost control. The Board notes that OPG is confident that the DRP (the largest current project) will have a range of $6 billion to $10 billion, a range of +25% to -25% around the midpoint of $8 billion. The Board expects OPG to do just as well on any other projects of substance. In addition to the need for rigorous cost control, the Board is also concerned that projects be assessed on an accurate analysis of the costs and benefits. A project which is reasonable on the basis of a particular cost estimate might well be unreasonable if the costs were 60% higher.

4.5 Other Revenues

OPG receives revenue from non-energy businesses and that revenue is applied as an offset to the nuclear revenue requirement. These businesses are heavy water services, isotope sales and inspection and maintenance services. The nuclear facilities also provide ancillary services as described in the Other Revenue – Hydroelectric section. The variance between forecast and actual ancillary services revenue are recorded in the Ancillary Service Net Revenue Variance Account – Nuclear.

The table below sets out the actual and forecast levels for other revenue.

Table 16: Other Revenues – Nuclear ($ million)

Revenue Source	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
NGD- Related Revenues:						
Heavy Water Sales & Processing	$30.3	$28.5	$25.5	$23.1	$17.3	$15.6
Isotope Sales (Cobalt 60 + Tritium)	7.0	10.2	7.2	9.3	9.6	11.0
Inspection & Maintenance Services	90.6	63.1	43.7	44.5	19.7	0.0
Total NGD-Related Revenues	127.9	101.7	76.4	77.0	46.6	26.6
NGD-Related Direct Costs	63.8	45.1	35.7	31.9	17.5	5.6
NGD-Related Contribution Margin	64.1	56.6	40.7	45.0	29.0	20.9
Ancillary Services	2.8	3.4	2.4	2.9	2.9	3.0
Other	1.7	0.3	0.8	0.1	0.1	0.1
Total	**$68.6**	**$60.3**	**$43.9**	**$48.0**	**$32.0**	**$24.0**

Source: Exh. G2-1-1, Table 1

The decrease in other revenues in the test period is largely the result of the reduced revenue from Inspection & Maintenance Services. The primary external customer for these services is Bruce Power. OPG and Bruce Power have agreed to terminate the service agreement effective June 2011. Parties focused their submissions on heavy water sales.

OPG proposed that effective March 1, 2011, all revenues and costs associated with the sale of surplus heavy water be excluded as an offset to the payment amounts. SEC, supported by VECC, submitted that net revenues from any sales of surplus heavy water should offset test period revenue requirement. While the surplus heavy water is fully depreciated and therefore not in rate base, SEC stated that it is still an asset on the books of the nuclear operations. In SEC's view, ratepayers paid for this heavy water – albeit prior to the Board's regulation of OPG - and are entitled to the benefits of any sales.

OPG replied that the surplus status of the surplus heavy water is an important factor to be considered. The heavy water is not required to support operations and the costs of storing and maintaining the assets are excluded from the revenue requirement. While acknowledging ratepayers had paid for the surplus heavy water, OPG referred to the

2006 ATCO decision of the Supreme Court of Canada, which stated "The payment does not incorporate acquiring ownership or control of the utility's assets."[26]

Board Findings

With the exception of revenues from heavy water sales, discussed below, the Board accepts OPG's forecast of other revenues from nuclear operations.

With respect to heavy water sales, the Board is guided by three decisions in addition to the Supreme Court's decision in ATCO, namely the decision in EB-2005-0211 (the "Cushion Gas decision")[27] and EB-2005-0211/EB-2006-0081 ("the Review Decision)[28] and the Divisional Court decision in *Toronto Hydro-Electric Systems Ltd. v. Ontario Energy Board*.[29]

First, the Board notes that the ATCO decision was not made in the context of rate-setting, a fact acknowledged by the Court itself, and in that respect is not strictly analogous to the current case. The Board's decision in EB-2005-0211, the "Cushion Gas Decision" is also relevant, but more analogous to the current case. In that case Union Gas was selling an asset that was surplus to utility requirements and would not need to be replaced. The Board determined that it did have the jurisdiction to order a splitting of proceeds. The Board further determined that a splitting of proceeds did not constitute "confiscation" (a term used in the ATCO decision) but rather was an exercise in ratemaking which could be designed to incentivize utility behaviour and protect ratepayers. The Board subsequently decided to review this decision on its own motion and ultimately confirmed the decision that the Board has jurisdiction to allocate proceeds to ratepayers for ratemaking purposes.

The Divisional Court's decision in *Toronto Hydro-Electric Systems Ltd. v. Ontario Energy Board* found that the Board's ratemaking powers gave it the authority to allocate the proceeds to ratepayers from the sale of certain properties (albeit ones that were being replaced by different properties), and noted that the Board had done so in order to mitigate the impact on ratepayers.

Revenue from the sale of heavy water is in many ways akin to any other revenue offset; in fact, that is how OPG proposed to treat it in the last proceeding and the Board

[26] *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4, para. 68.
[27] Decision with Reasons, June 28, 2006.
[28] Decision and Order, January 30, 2007.
[29] [2009] O.J. No. 1872.

approved it. When the heavy water was purchased and/or produced, it went into OPG's rate base. Over the years, ratepayers at least notionally paid all of the costs associated with these assets both through depreciation expenses and through the cost of capital on the amounts in rate base. In other words, rates were based on the total recovery of the capital costs, often explained as both a return of capital and a return on capital. As the assets were fully depreciated by the time OPG applied for its first payments order, the Board did not set or approve the payment amounts related to these assets. However, they would have formed part of the payments that OPG recovered from ratepayers prior to OPG's regulation by the Board.

OPG observes in its reply argument that any heavy water that is sold will be surplus, and not required to support the regulated operations. Although this is true, that does not differentiate it from other types of revenue offsets, for example, isotope sales. Isotopes produced by OPG and sold to a third party are not used to support regulated operations. Almost by definition, anything sold (whether a good or a service) and used as a revenue offset is surplus to utility operations. And yet it is the long standing practice of this Board, both for OPG and for the many gas and electricity distribution and transmission companies it regulates, to use its ratemaking (or payment making) powers to apply these revenues as an offset to the utility's revenue requirement. In some cases these offsets can have a material impact on rates. The rationale is not based on any ownership claim; rather it is based on the regulatory principle that only reasonable costs are eligible for recovery and that a reasonable level of cost is the level of cost associated with the efficient operation of the system. Therefore, if costs can be reduced by selling products or services to third parties, then ratepayers should only be required to pay the efficient level of costs, which reflects the revenue offsets from the efficient use of the assets. It may also be appropriate to provide utilities with incentives to run operations as efficiently as possible. For this reason, the revenue offsets are sometimes shared between the company and the ratepayer as a means of encouraging the company to maximize those revenue offsets – for its benefit and also the benefit of the ratepayer.

Disputes surrounding the Board's jurisdiction to use these revenues as offsets tend to focus on revenues from sales of capital assets: for example heavy water, cushion gas, or real property. From a ratemaking perspective, however, there is little to distinguish the ratepayer contribution toward capital assets from the ratepayer contribution to services sold by a utility. Although the accounting treatment is different (the costs of capital assets are recovered through rates/payments over a number of years through depreciation and a return on rate base, whereas O&M costs are expensed and recovered through rates/payments in the year they occur), the underlying costs for both the provision of services to third parties and surplus assets are borne by ratepayers. For example, OPG is only able to make isotope sales because ratepayers pay the costs associated with OPG's capacity to provide these services. In that light, no party argued that using these revenues as a revenue offset is inappropriate. However, OPG is able to provide these services because it has "surplus" resources.

The Board is therefore not convinced that there is a fundamental difference between revenues a utility earns through the sale of capital assets and those it earns through the sale of services. By using the revenue from heavy water sales as revenue offsets for the purpose of setting rates or payments, the Board is no more confiscating the capital assets of a utility than it is confiscating the labour of utility's employees when it uses revenues from isotope sales as revenue offsets. Indeed, as noted in the cushion gas decision, the suggestion that such offsets amount to confiscation or some type of ratepayer ownership of utility assets is miscast. The Board's power to set payment amounts (or rates) is a broad one. The Board must have regard to all of a utility's costs, but must also consider the utility's revenues.

The Board concludes that the same approach is appropriate with respect to heavy water sales. Namely, is there a good reason to split proceeds from heavy water sales? The Board concludes there is, both to protect ratepayers and to provide an appropriate incentive to OPG. The proceeds of the sale are an appropriate offset to the costs that have otherwise been borne by ratepayers. This offset is appropriate as it recognizes the efficient utilization of the assets and hence the efficient level of costs which are reasonably borne by ratepayers. It is also appropriate to share the proceeds with OPG in order to provide the company with an incentive to maximize the revenues. The Board orders the forecast proceeds for 2011 and 2012, as identified by OPG, to be split 50/50 between ratepayers and customers. As these amounts were provided in confidence, the Board will not disclose them in this decision. However, OPG will be required to incorporate these amounts in its preparation of the draft payments order. No variance account will be established. OPG will bear the risk associated with the level of sales being different than forecast.

5 DARLINGTON REFURBISHMENT

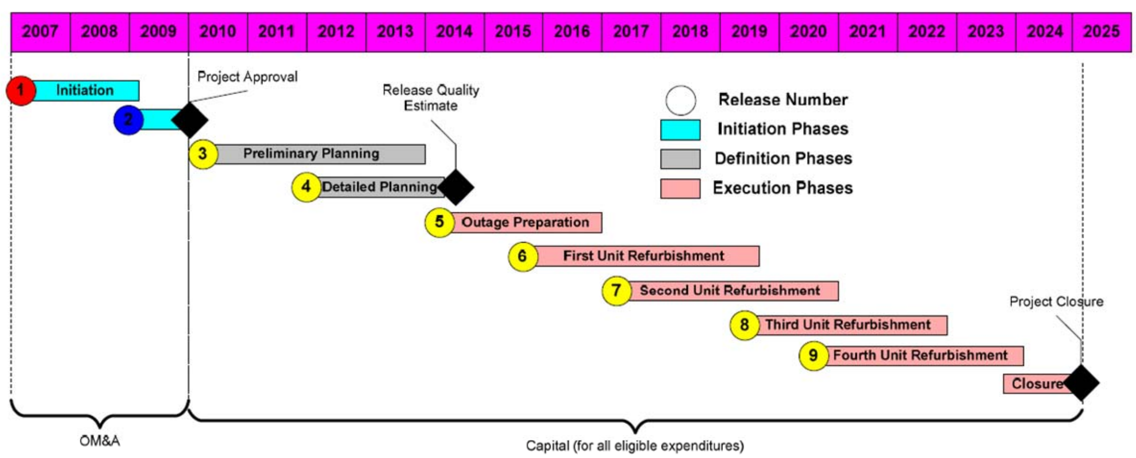
5.1 Darlington Refurbishment Project

OPG intends to refurbish the four units at Darlington and preliminary planning is underway. The refurbishment is expected to extend the operating life of the units by approximately 30 years, to about 2051.

OPG's position is that the Darlington Refurbishment Project ("DRP") is covered by section 6(2)4 of O. Reg. 53/05 because it will both refurbish the Darlington station and increase its output by allowing it to operate for a longer period.

OPG's Board of Directors approved the decision to proceed with the DRP on November 19, 2009. The Board of Directors also approved the release of funds for the definition phase of the project to complete preliminary planning and the overall timing and release strategy. Figure 1 shows the planned timeline for phases of the DRP. During the test period, preliminary planning will continue, and detailed planning is expected to begin. In 2014, following completion of the planning phases, there will be further approval by OPG's Board of Directors of the "release quality estimates" and the execution phases of the project will begin.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



Source: Exh. D2-2-1, p. 10

OPG provided an Economic Feasibility Assessment of DRP as part of the application. That assessment concluded with high confidence that the DRP will have a levelized unit energy cost ("LUEC") of 6 to 8 cents per kWh ($2009). The projected cost of the DRP is in the range of $6 to $10 billion ($2009). OPG filed a letter from the OPA concurring that, at a LUEC of 6 to 8 cents per kWh, the DRP is an economic alternative to combined cycle gas turbines. OPG also filed a letter from the Minister of Energy and Infrastructure dated February 4, 2010. The Minister indicated that the government is satisfied that the analysis performed by OPG resulted in optimal decisions regarding Darlington Refurbishment and that the government concurs with the decision taken by OPG's Board of Directors on November 19, 2009. OPG indicated that it will bring forward an update on DRP and the planned expenditures and work plans for 2013-2014 in its next application.

In the current application, OPG seeks approval for the following:

- Test period OM&A costs of $5.9 million and $4.5 million in 2011 and 2012, respectively;
- Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from extending the service life of Darlington to 2051 and the change in nuclear liabilities associated with Darlington Refurbishment;
- Disposition of the difference between forecast 2010 non-capital costs associated with DRP and the costs underlying the current payment amounts, which are a credit of approximately $23 million No objections were raised in respect of this issue and the account is addressed in Chapter 10; and
- An increase in rate base to reflect inclusion of Construction Work in Progress ("CWIP") for the DRP.

OPG's evidence was that the net effect of these requests is a reduction in the test period revenue requirement of $197.1 million. As noted in Table 14, the forecast capital expenditures for this project are $105.2 million in 2011 and $255.8 million in 2012.

Some parties questioned the extent to which OPG's Board of Directors has actually approved the DRP, and the scope of those approvals.

PWU argued that OPG is entitled to recover the cost of the DRP as prescribed by O. Reg. 53/05 section 6(2)4 if the Board finds the past expenditures were prudently incurred and future expenditures were prudently made. It is PWU's position that the test period costs are reasonable and prudent. The Society also submitted that the DRP budget should be approved as submitted. Board staff agreed that test period costs are appropriate and should be approved so that OPG can plan its work on the DRP.

Other parties indicated varying levels of support for OPG's requested approvals.

CME supported the DRP plan and urged the Board to find that OPG's evidence is sufficient to support a tentative conclusion that the DRP is likely to be economically feasible. However, CME called on the Board to make it clear in its decision that if OPG fails to objectively establish and confirm that the DRP continues to have positive economic feasibility in future proceedings the Board may require OPG to write down the value of Darlington assets for regulatory purposes.

SEC argued that the Board should approve the test period spending but suggested that OPG should aggressively limit its ongoing financial commitment in the event the project does not proceed. SEC suggested that the Board should clearly state that regardless of any approvals for spending in the test period, OPG remains at risk for the prudence of the project and the spending related to it. To address this concern, SEC urged the Board to include the following in its decision:

- OPG should be cautioned to use every effort to minimize the commitments it is making for spending beyond the test period, and to take all steps to ensure that the cost of any termination decision will be as low as possible;
- In the next payment amounts application, OPG should provide a full package of information supporting the project, equivalent to that which would be required for a leave to construct application, and should assume that no further spending will be authorized until the Board has reviewed that application. Alternatively OPG should obtain a binding legal approval for the project from another source, such as the government, if it wants further spending approvals from the Board; and
- If OPG decides not to return to the Board for 2013 rates, the company should be fully at risk for any spending and commitments in 2013 and beyond, and that barring extraordinary circumstances, no such spending will be recovered from ratepayers.[30]

[30] SEC Argument, para. 4.5.29.

AMPCO supported the exploration of a refurbishment option for Darlington but urged the Board to be clear that approval to proceed with further project definition does not constitute any kind of approval of the prudence of the project. AMPCO also questioned the reliability of OPG's cost estimates in the absence of evidence about its contracting strategies. AMPCO submitted that OPG should be required to inform the Board of its contracting and procurement plans. AMPCO cited ongoing problems with refurbishments at Point Lepreau and Bruce Power in support of its position that the Board should carefully monitor the progress and outlook of the DRP.

OPG suggested that SEC's and AMPCO's submissions amounted to micro-managing, which would put the DRP schedule at risk, could drive up project costs, and is not an appropriate role for the Board.

VECC submitted that the Board should explicitly reject any notion that its decision provides any level of approval for OPG's expenditures with respect to the DRP, as OPG has specifically said in its Argument in Chief that it is not seeking Board approval of the project. VECC also submitted that a DRP variance account be established to allow the Board to track OM&A expenses for future prudence review.

Board staff questioned the certainty of the DRP cost estimates, referring to cost over runs of previous projects. Board staff also questioned the comprehensiveness of the LUEC analysis and the depth of the OPA support as the OPA relied on OPG's economic input assumptions. CCC stated that the OPA's analysis was below the threshold of exhaustive and argued that the Board should place no weight on the OPA's support.

GEC argued that in the absence of any case supporting the economics of the project in comparison to other alternatives, the Board should not offer any assurance of cost recovery to OPG at this stage by accepting the capital budget as reasonable. GEC argued that there is no analysis to support OPG's assertion that the DRP is in the public interest. GEC submitted that, "Without a *prima facie* case that the project is likely to be in the public interest there can be no finding that the capital budget is reasonable."[31]

OPG indicated that it is not seeking approval of costs beyond the test period and so, in its view, the Board does not need to address the issue of the sufficiency of evidence for post-2012 costs. OPG submitted that what the Board should confirm in its decision is

[31] GEC Argument, p. 39.

that its approval of the test period revenue requirement impacts and accounting changes constitutes its agreement that OPG's proposed test period activities are reasonable based on the evidence. OPG further submitted that any subsequent review should only relate to the prudence of OPG's execution of test period activities and not to the prudence of having undertaken these activities.

With respect to public interest, OPG submitted that the Province has already determined that DRP is in the public interest, and referred to the Minister's letter endorsing the decision to proceed with the DRP, and the inclusion of the DRP in the Long Term Energy Plan.

<u>Results of Service Life Extension to 2051</u>

OPG proposed changes in rate base, return on rate base and tax expense resulting from the service life extension of Darlington. The major impacts of the service life extension are higher asset retirement obligation ("ARO") and asset retirement cost ("ARC"). However, due to the project end of service life of 2051, there is an overall net reduction to the revenue requirement in the test period. These accounting changes were made effective January 1, 2010.

Board staff questioned whether the definition phase of the DRP met the requirements of CICA Handbook section 3064 criteria for capitalization for projects under development since CICA Handbook section 3061 provided limited accounting guidance in this area. OPG replied that the correct reference is section 3061 and that it has properly followed the CICA guidance.

Several parties questioned whether the accounting changes were premature. Board staff noted that if the Board decided not to approve the revenue requirement impacts associated with service life extension of the DRP, this decision would introduce a separate and second set of books that would differ significantly from OPG's GAAP reporting. GEC submitted that if DRP does not proceed, the reductions in contributions to decommissioning costs will have to be made up by future ratepayers, possibly resulting in a disproportionate rate burden. GEC asserted that the revenue requirement impact of the proposed accounting changes should be not be implemented because there is no firm decision on the Darlington life extension plan.

SEC argued that the reduction in revenue requirement should not be implemented as it would be problematic in the event that DRP is later determined not to be the best generation option. As OPG has already implemented the accounting changes, SEC proposed a DRP Accounting Variance Account. Payments would be collected from ratepayers, but the equivalent of the proposed reduction in revenue requirement would accumulate in the account. If the DRP proceeds, ratepayers would be credited with the savings. OPG questioned whether SEC's proposed account could even be recognized for financial statement purposes as it would be a contingent asset, only realized if DRP did not proceed.

VECC noted that the impact of the DRP, with the CWIP in rate base removed, amounted to a credit to customers of $235.2 million of which $188.8 million is nuclear liability related. On the basis of the protection afforded OPG under the Ontario Nuclear Funds Agreement ("ONFA"), the nuclear liability deferral account and the ability to unwind the impact of depreciation rate changes, VECC submitted that the Board could approve OPG's DRP requests (with the exception of CWIP). VECC argued that if DRP does not proceed, the updated reference plan under ONFA and the operation of the nuclear liability deferral account will true up the impacts.

As noted above, OPG implemented the accounting impacts of the Darlington service life extension effective January 1, 2010. SEC and VECC argued that these changes were inappropriate. The parties argued that the changes had the effect of reducing the revenue requirement in 2010 by $64.2 million, and that this amount should be credited to ratepayers. SEC further added that the Board should declare OPG's 2010 rates interim, lest an argument of retroactivity impede implementation of the credit. OPG replied that the accounting changes with respect to ARO, ARC and Darlington life extension which took place on January 1, 2010 have been audited by external auditors. OPG characterized SEC's proposal as retroactive ratemaking.

OPG also argued that a complete reversal of these accounting adjustments would raise an issue of consistency with the Board's decision in EB-2007-0905 as it pertains to the Bruce facilities.

Board Findings

The Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to the DRP as it is designed to refurbish a generating facility to which O. Reg. 53/05 applies. All cost variances (both capital and operating expenses) will be captured in the account for later disposition. Therefore, the Board's mandate is to ensure that OPG recovers the costs of the DRP if the Board is satisfied that these costs were prudently incurred. However, in the Board's view this does not preclude the Board from assessing the reasonableness of the proposed expenditures before they are made. The Board agrees with OPG that the prudence review of those aspects of the work which are found to be reasonable in this proceeding will be limited to the differential between the proposed expenditures and the actual cost.

In this proceeding, the Board is of the view that its role is to determine the following:

- whether the planned capital and OM&A spending on the DRP in 2011 and 2012 is reasonable;
- whether OPG's decision to reflect the planned extension of the end of life for Darlington for accounting purposes is reasonable; and
- whether CWIP should be allowed in rate base.

Approval of the expenditures for the test period should not be taken as an acceptance of the business case underlying the entire project. Once the DRP reaches the stage of having a release quality cost estimate the Board expects to examine the reasonableness of proceeding with the project. At that time, the Board may consider establishing a framework within which prudence could be examined should the project proceed forward. Other approval mechanisms, including some form of pre-approval of future expenses, may also be considered. The Board's findings in this proceeding are not determinative of the outcome of that review.

The Board expects OPG to file updated information on its progress for examination in the next proceeding.

The Board accepts OPG's evidence that its Board of Directors has given approval to proceed with the DRP. Of course, as it is a phased project, the question of whether to continue with the project or terminate it will be addressed at each Board of Director approval stage. It remains open to OPG to recommend to its Board that the project not be continued, and it remains open to the Board of Directors to halt the project.

OPG urged the Board to find that the Minister's letter concurring with the DRP means that the DRP is, by definition, in the public interest. The Board declines to make such a finding, but is also of the view that it does not need to make a finding that the project as a whole is in the public interest in order to grant the approvals sought by OPG in this application. The Board disagrees with GEC's position that public interest must be determined before a determination on the capital budget. For purposes of this Decision, the Board's focus is on the reasonableness of the test period expenditures, including a determination as to whether they are supported by the business case. The Board also observes that nuclear refurbishment is included in the Supply Mix Directive, which is not subject to the Board's approval.

A number of parties expressed concerns about the quality of the business case for the DRP. The Board shares their concerns about the likely overall costs of the project and the ability of OPG to keep the project in the $6 billion to $10 billion range currently forecast. Quite apart from whether OPG has improved its performance, the Board has concerns because no CANDU plant has yet been refurbished on budget. Despite these limitations, the Board finds that for the purposes of approving the spending in the test period, the business case is a reasonable underpinning, and the Board approves the OM&A spending as forecast. OPG did not seek specific approval of the capital expenditures, but it did request the inclusion of CWIP in rate base and that request is addressed below. The Board does not normally give approval to capital expenditures for projects which come into service after the test period except in the case of a leave to construct application. With respect to all other capital budgets in this case, the Board has limited itself to addressing the amounts for items entering into service in the test period. However, the Board finds the forecast DRP capital expenditures for the test period to be reasonable.

If the results of the definition phase demonstrate that the costs will rise significantly, the Board expects that OPG's Board will reassess the project at that time. The Board notes the high level of confidence expressed by OPG's witnesses in the costs presented despite OPG's history of cost over-runs and the current experience with the cost overruns of refurbishments at Point Lepreau and Bruce. If there are cost overruns with the DRP, the Board does not expect OPG to suggest that they could not have been foreseen at this stage. This factor may well be considered in any prudence review.

As the DRP is a multi-year project the Board expects that in future payments cases the business case will be updated as OPG seeks further approvals for the project. The Board will therefore not require any additional reporting as requested by SEC, nor will there be any caveats placed in advance on what might happen if OPG does not file an application for 2013. As indicated in the findings related to the Pickering B Continued Operations Project, the Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the project going forward, the Board will be interested in examining whether any performance incentives might be appropriate within the parameters of O. Reg. 53/05 and the variance account.

The second major issue is whether the changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from service life extension to 2051 are appropriate, from a regulatory perspective.

The Board accepts OPG's evidence that the restatement of the service life extension is in accordance with the decision of the company's Board of Directors to approve the DRP, with GAAP, and as far as it affects net revenue from the Bruce lease arrangements, in accordance with the Board's decision in the previous proceeding.

The only concern with extending the service life for regulatory purposes is what the future impacts would be if a later decision was made to not proceed with the DRP, and the end of life dates were changed to an earlier date. Some parties were concerned that there might have to be large rate increases to recoup the funds not collected during the test period. The Board agrees with VECC that the impact of any future restatement can be reasonably managed, given the protection afforded the company through the ONFA, the nuclear liability deferral account and the possibility of the unwinding of the impact of depreciation rate changes. If DRP does not proceed, the inclusion of DRP in the updated reference plan under ONFA, which is expected in 2011 for the next five-year period of 2012-2016, would result in financial impacts being captured in the nuclear liability deferral account.

The Board notes that by not filing a 2010 payments case, OPG benefited from the changes in the accounting treatment of the DRP in 2010, but ratepayers did not. OPG could have sought an adjustment to the Reference Plan as a result of the changes, and that would have ensured that the revenue requirement impacts would be captured in the variance account; it is unfortunate that OPG chose not to do so. However, the Board is not prepared to accede to SEC and VECC's request to, in effect, reverse the 2010 accounting changes relating to the DRP, or to credit ratepayers with the difference that resulted. The 2010 rate year is not the subject of this application. The Board is not prepared to reopen one element of the previous decision without reviewing the entirety of the 2010 rate year.

5.2 Construction Work In Progress

OPG's application included a proposal to include Construction Work in Progress ("CWIP") for the DRP in rate base. This would result in an addition to rate base of $125.5 million in 2011 and $306.0 million in 2012. These additions to rate base would receive the approved weighted average cost of capital which would result in a revenue requirement of $11.1 million in 2011 and $26.8 million in 2012 for a total of $37.9 million for the test period. OPG also proposed that any recovery of depreciation on this capital would be deferred until the assets come into service. OPG maintained that there would be benefits to ratepayers from this proposal through rate smoothing and lower credit costs.

Two expert witnesses filed reports on this issue – Mr. Ralph Luciani of Charles River Associates on behalf of OPG and Mr. Paul Chernick on behalf of GEC. Both appeared as witnesses at the hearing.

Mr. Luciani's report was largely a presentation of examples in the US where CWIP has been allowed for the development of nuclear facilities and a discussion of their potential as precedents in OPG's situation. Mr. Luciani's report did not describe or discuss the various circumstances in which states had decided not to allow CWIP.

Mr. Chernick's report suggested that the cases in which CWIP has been allowed in the US were not applicable to OPG because the circumstances are quite different. He also reviewed the circumstances in several US jurisdictions which had decided not to allow CWIP, and suggested that they were more akin to the situation in Ontario.

OPG's position was that inclusion of CWIP in rate base is warranted in this case because it meets the criteria for qualifying investments specified by the Board in its EB-2009-0152 report, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, dated July 15, 2010 (the "Report").

OPG argued that the Board should take the criteria set out in the Report into account in evaluating the CWIP proposal and offered the following evidence in support of each:

> **The need for the project**: The Government of Ontario has endorsed the need for the project by concurring with OPG's decision to proceed with the project and by including it in the government's energy plans.

The public interest benefits of the project: The Minister's support and approval of the project is indicative that it is in the public interest. OPG noted that the Government of Ontario has indicated its support for the DRP, and that this support should be sufficient for the Board to conclude that the DRP is needed and in the public interest. OPG also pointed out that there is no provision in the Act or related regulations for the Board to grant approval for the project. While not currently obligated to undertake the DRP, OPG believes that Ontario's energy needs will require OPG to proceed with the project.

The overall cost of the project in absolute terms: The project will cost between $6 billion and $10 billion and is the largest project being undertaken by a regulated utility in Ontario.

The risks or particular challenges associated with the completion of the project: The project's risks and challenges are broadly similar to those faced by *Green Energy and Green Economy Act* ("Green Energy Act") projects, including the potential for delays, public controversy and the recovery of costs.

The cost of the project in proportion to the current rate base of the utility: The project's cost range of $6 billion to $10 billion is greater than OPG's $4 billion nuclear rate base for 2012. The upper bound of the range is greater than OPG's combined nuclear and hydroelectric rate base of $7.8 billion.

The reasons given for not relying on conventional cost recovery mechanisms: The reasons are rate shock, impact on credit metrics and the subsidy resulting from the difference between Interest During Construction ("IDC") rate and the Allowance for Funds Used during Construction ("AFUDC") rate. Rather than large increases of $350 million to $550 million in the revenue requirement when the DRP is added to rate base in 2020 and in subsequent years, the revenue requirement would increase more gradually starting in 2011. OPG's scenario would have rates increasing by 1 to 1.8% per year each year starting in 2011, rather than a few years with 5 to 10% increases starting in 2020.

Whether the utility is otherwise obligated to undertake the project: While OPG was directed by its shareholder to study the refurbishment of the Darlington units, it has not received a directive to complete the project. Pursuant to the

Report, a utility will not have to establish that “but for” CWIP treatment, the project will not proceed.

OPG argued that the inclusion of CWIP in rate base for the DRP meets the criteria for qualifying investments specified by the Board in the Report.

OPG’s case for CWIP was supported the PWU and the Society. The PWU submitted that this proceeding is not the forum to re-hear arguments about the appropriateness of alternative regulatory mechanisms but whether the alternative mechanisms contemplated by the Report should be applied in the case of the DRP. PWU criticized Mr. Chernick’s evidence as a re-argument of matters decided in the Report rather than a consideration of the merits of the case presented by OPG.

Other parties, including Board staff, submitted that the Board should deny OPG’s request.

First, parties disagreed with OPG’s claim that the DRP falls within the scope of the Report as a qualifying investment, and that the CWIP proposal should be evaluated on this basis. These parties argued that the DRP is not a Green Energy Act related investment. They noted that the Report deals with rate-regulated activities of distributors and transmitters and that despite OPG’s request during the Board’s consultation on the Report, the scope of the Report was not expanded to include generation investments.

In reply argument, OPG submitted that the Report provides for the consideration, on a case-by-case basis, of applications to include CWIP in rate base in advance of a project being declared in-service. OPG sees its proposal as consistent with the Chair of the Board’s statement of July 3, 2009 regarding the removal of barriers to infrastructure investment in Ontario.

Intervenors also argued that when evaluated on the basis of the factors suggested by OPG, the DRP did not warrant alternative regulatory mechanism (i.e. CWIP) treatment, arguing that:

- OPG had failed to demonstrate that significant rate shock would be avoided;
- It would be imprudent to recover costs when overall projected costs are not yet defined;

- It would be premature to grant recovery when the project lacks full authorization to proceed, as OPG's Board of Directors has only given permission to proceed with the definition phase of the project;
- The public interest would not be served since the proposed treatment is more costly to ratepayers on a Net Present Value basis;
- Proposals which front-end load costs are disadvantageous to rate-payers since ratepayers' financing costs are higher than OPG's;
- Intergenerational inequity results when ratepayers are asked to pay for costs and there is no corresponding benefit for them;
- OPG's existing credit risk has been unaffected by the DRP expenditures underway; and
- No evidence has been provided that any downward evaluations are forthcoming.

OPG argued that the Board should not consider any of the arguments regarding intergenerational inequity, the "used and useful" principle and differences in ratepayer and OPG financing costs as these have already been dealt with in the Report.

CCC and other intervenors commented that, based on OPG's own analysis, the rate shock would not be that significant, and in the meantime ratepayers will be paying for 10 years for an asset that is not yet in use.

CCC argued that OPG's concern with its credit metrics was hypothetical and unsupported by any evidence of the impact of not having CWIP. In response, OPG quoted Fitch Ratings, that "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk" and referenced Standard and Poor's observation that OPG had weak cash flow metrics. OPG stated that it is not surprising that it would not be able to quantify the impact of the DRP on its credit metrics until the Board's decision is issued, project financing finalized and rating agencies have had the opportunity to complete the assessment. OPG also pointed out that the incremental risk associated with the DRP is not reflected in OPG's current credit rating and cost of capital.

CME also observed that the timing of the request for CWIP treatment is inopportune, given the increases in electricity bills being experienced by customers, but suggested that OPG may wish to re-apply for this treatment once electricity rates have stabilized.

Board staff submitted that in the event the Board accepts the inclusion of CWIP in rate base, the return should be limited to interest costs similar to the treatment afforded Hydro One in the EB-2006-0501 decision. OPG argued that its circumstances are different from those faced by Hydro One, and so interest rate treatment should not apply. OPG submitted that as a result of this suggestion, OPG's shareholder would be subsidizing the DRP, which OPG estimates to be $200 million to $300 million.

Board Findings

The Board finds that the Report is clear that the policy could apply in other circumstances beyond the Green Energy Act and beyond transmission and distribution infrastructure. However, the Board finds that OPG's request for CWIP is premature, given that the DRP is only at the definition stage.

The Board notes that its policy, as set out in the Report, contemplates the adoption of these mechanisms in the context of an overall approval of a project, generally either through a leave to construct application or through a rates case. The Board notes that this is consistent with the approach taken by US jurisdictions that allow CWIP in rate base, other than those which allow for CWIP through legislation. As the Board is not considering the overall scope of the DRP at this time, it finds that it is premature to adopt any special treatment. The Minister's letter indicating support for the project is not sufficient for this purpose. While it may be persuasive, it does not bind the authorities that will need to approve the project. At the very least, it will require some form of approval under the *Environmental Assessment Act*, and will have to be included in the IPSP.

In filing Mr. Luciani's report in support of its position, OPG sought to persuade the Board that using CWIP to finance nuclear power plants was becoming the accepted approach in US jurisdictions. The Board allowed Mr. Luciani to give evidence despite the reservations expressed by several of the intervenors about his independence given the nature of his retainer which they asserted cast him in the role of advocate. The Board ruled that the evidence would be allowed but that it would take the nature of his retainer into account when considering the weight to be given it.

Of greater concern to the Board is the nature of Mr. Luciani's report itself. While his report did not purport to be a review of all US jurisdictions, it was a completely one-sided account of the issue as it included only those jurisdictions which had decided to allow CWIP and neglected to mention any that did not. In cross-examination, Mr.

Luciani admitted that there were many jurisdictions that had rejected CWIP as a funding mechanism. In the Board's view the contents of his report created a misleading impression about the level of acceptance of CWIP as a mechanism. The Board expects objectivity from independent expert witnesses.

In any event, the Board finds that most of the US jurisdictions that have allowed CWIP for nuclear plants have quite different circumstances than those facing OPG. The companies concerned are generally private sector operators who require incentives to build and the CWIP approvals have been granted in the context of overall project approvals. Neither of these circumstances applies to OPG.

The Board therefore gives little weight to Mr. Luciani's evidence and finds that it cannot be relied on by OPG as the underpinning for its request for CWIP.

The Board will not approve CWIP in rate base at this time. The Board is prepared to consider the proposal again in the future, but the Board will expect better evidence in support of the proposal. For example, prior to approval of CWIP, the Board would expect to see more persuasive evidence than was presented in this application as to the benefits for ratepayers in terms of improved credit metrics and rate smoothing. On the latter point regarding rate smoothing, the Board would expect to see additional evidence to support the proposition that ratepayers are better off if they begin to pay sooner for these large multi-year projects.

6 CORPORATE COSTS

6.1 Compensation

The following table summarizes historic and test period compensation levels.

Table 17: Compensation ($ million)

Organization	2007	2008	2009	2010	2011	2012
Nuclear	$1,187.90	$1,206.13	$1,265.01	$1,243.41	$1,196.23	$1,210.84
Regulated Hydro	42.29	45.14	45.47	47.87	50.36	52.73
Allocated Corporate Support	122.19	125.95	128.85	131.41	135.15	138.59
TOTAL REGULATED COSTS	**$1,352.38**	**$1,377.22**	**$1,439.33**	**$1,422.69**	**$1,381.74**	**$1,402.16**

Note1: Includes total wages, benefits, current service cost component of the Pension/OPEB costs and annual incentives.

Note 2: Does not reflect OPG's impact statement

Source: Issue 6.8, Exh. L-1-74

OPG employs approximately 10,000 staff in the regulated business, 95% of which support or are employed in the nuclear business. Of the staff in the regulated business, 90% are unionized: two thirds represented by the PWU and one third by the Society.

OPG stated that, as a result of collective bargaining, the general wage increase for the PWU and Society has been between 2% and 3% for the past number of years. As noted in the application, the forecast wage increase for each test year is 3% for management and 3% for both unions. OPG has forecast an additional 1% increase to account for step progressions and promotions for staff within the unions. OPG's labour agreement with the Society expired on December 31, 2010 and its agreement with the PWU expires on March 31, 2012.

OPG maintained that its staff must be highly skilled and noted that 73% of the positions require post secondary education. OPG indicated that these employees are in demand across the country. The OPG workforce is mature and OPG estimated that 20% to 25% will need to be replaced between 2010 and 2014.

Towers Perrin conducts a survey which compares compensation data among a variety of employers across Canada where job matches are sufficiently strong. Although OPG participates in the Towers Perrin study, the survey is not prepared specifically for OPG.

OPG used the data from the survey to prepare a chart comparing OPG's salary levels with those of other organizations in the survey. Specifically, the chart shows the variance between OPG's salary levels and the 75th percentile of the comparators for 30 positions. OPG selected the positions that were included in the chart based on its judgment of which ones were the best matches.[32] Together, these positions account for approximately 30% of OPG staff who work in the regulated businesses. The chart showed that OPG was above the 75th percentile for some positions, and below it for others, and was slightly above the 75th percentile on an overall basis.[33] OPG selected the 75th percentile as the most appropriate point of comparison (Towers Perrin provided data for the 10th, 25th, 50th, 75th, and 90th percentiles). Towers Perrin did not participate in the preparation of the chart, and did not provide OPG with advice concerning the best comparable positions, or the use of the 75th percentile as a comparator. Although the Towers Perrin survey included data on both base salaries and total cash compensation, the chart prepared by OPG used the base salary data only.

OPG maintained that the compensation for unionized employees is appropriately benchmarked at the 75th percentile of the market for companies surveyed by Towers Perrin due to the nature and complexity of work performed by OPG staff. OPG advised that the 30 positions in the survey accounted for 2,804 OPG employees. In order to bring this set of positions to the 75th percentile, $16 million would have to be removed from payroll, and in order to bring the positions to the 50th percentile, $37.7 million would have to be removed from payroll.

In response to recommendations of the Agency Review Panel,[34] management compensation has declined by 12.6% in the period 2007-2009. OPG benchmarks management compensation against the 50th percentile of market. In the impact statement filed on September 30, 2010, OPG stated that it is removing management wage escalation for the period to April 1, 2012 in response to the *Public Sector Compensation Restraint Act*. OPG proposed to offset the $12 million reduction related to management wages against the $13 million increase in Canadian Nuclear Safety Commission fees. The latter is discussed at section 4.3.1.

The Society and the PWU supported OPG's application. The Society submitted that if the Board believes that a 3% economic increase is unlikely to be granted by an

[32] Tr. Vol. 8, pp. 166-168.
[33] Exh. F4-3-1, pp. 30-31.
[34] The Agency Review Panel's June 27, 2007 report recommended changes to the way executive compensation would be determined at Ontario's five electricity sector institutions, which included OPG.

arbitrator, then it may consider the use of a variance account to capture any amount less than 3%. In the PWU's view, the Board needs to consider whether the current compensation rates for PWU represented staff was reasonable and prudent when the present collective agreement was entered into in April 2009. Regarding comparisons, the PWU submitted that simply comparing OPG compensation with other non-nuclear employers is not evidence of a lack of prudence on the part of OPG. The PWU also submitted that an assessment of compensation requires an assessment of productivity and skill level.

Board staff questioned OPG's choice to benchmark at the 75th percentile, noting that a number of positions OPG selected from the Towers Perrin survey are generic positions (i.e., labourer, warehouse supervisor). In addition, staff noted that OPG was not able to identify any positions that were exclusively related to specialized skills required of an employee working in a nuclear plant environment, because Towers Perrin did not categorize the positions in this way. Staff submitted that the rationale provided by OPG for use of the 75th percentile was not substantiated, and that the 50th percentile is more consistent with the use of the median by the Board in relation to Hydro One.[35] Staff submitted that it was appropriate to remove $37.7 million from annual revenue requirement based on moving the 30 positions to the 50th percentile. Staff also submitted that it was appropriate to reduce the revenue requirement associated with the Society wage increase from 4% to 2.5%, as this was more consistent with recent arbitration decisions entered into evidence by PWU. These arbitration decisions resulted in increases of 2%, 2.25% and 3%.

CME submitted that the Board can assume that the Towers Perrin report is likely representative of all OPG incumbents, and urged the Board to consider higher disallowances than those suggested by Board staff. CME extrapolated the Towers Perrin results to all employees and estimated reductions of $134.48 million assuming reductions to the 50th percentile. CCC supported CME's position.

SEC submitted it would be unfair to require OPG to move to the 50th percentile immediately and proposed a 25% reduction in 2011 (of the total amount required to match the 50th percentile) and 50% in 2012, amounting to reductions of $33.7 million for 2011 and $67.3 million for 2012. SEC observed that where the Board has set limits previously, regulated entities have responded favourably. SEC further proposed the elimination of the licence retention bonus. With respect to the licence retention bonus,

[35] Decision with Reasons, EB-2008-0272, May 28, 2009, pp. 28-31.

OPG maintained that it is appropriate due to the effort and resources required to retain licences and the comparable practice at Bruce Power.

OPG replied that it is bound by its collective agreements and that there is no basis for selecting the 50th percentile as the appropriate benchmark. OPG argued that skills and training requirements are extensive, even for positions viewed as generic by parties. OPG noted that intervenors relied on no evidence to support their view that the 50th percentile was the appropriate target.

With respect to the Ontario Hydro successor companies, OPG provided a wage comparison of OPG to Hydro One for comparable Society positions. Staff entered into evidence a similar comparison for certain PWU positions from the EB-2010-0002 Hydro One application. Board staff submitted that there is no justification for OPG to consistently pay its staff more than Hydro One for generic positions such as mechanical maintainer, regional field mechanic or labourer.

OPG maintained that its compensation compares favourably with the other successor companies, and that on a weighted average basis, OPG's wages are 10% lower than Bruce Power – the only other large nuclear operator in the province.

OPG noted that one Ontario Hydro successor company has undergone arbitration and received a 3% increase excluding progression and promotion. OPG argued that the Board staff position of 2.5% has no basis and that the reduction should be at most 0.5%.

As noted in the section on benchmarking, there was difficulty reviewing compensation data and trends due to OPG's use of headcount for the historical period and FTEs for the future period. Parties were generally of the view that FTEs should be used for all periods. SEC further submitted that OPG should be required to file compensation information in the format of Appendix 2K used for electricity distributors.[36] OPG responded that it would file the equivalent of Appendix 2K which is based on FTEs, to provide historical and forecast data on a comparable basis.

Board staff and SEC also submitted that OPG should be directed to file an independent full compensation study with its next application similar to the study that the Board

[36] Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications, June 28, 2010.

required of Hydro One.[37] Board staff noted that, given total compensation costs of almost $2.8 billion over the test period, the cost of such a study would be reasonable.

OPG argued that an external study of compensation was not required because the study would be expensive, at a cost of about $0.5 million to $1 million, there are a limited number of nuclear operators in Canada, and OPG is bound by its collective agreements. OPG stated that if it was directed to complete a study, it would do so provided funding was allocated.

Board Findings

Compensation makes up a very significant component of OPG's total operating costs. The Board is concerned with both the number of staff and the level of compensation paid in light of the overall performance of the nuclear business. Each of these issues will be addressed separately.

The lack of comparable data (use of headcount for the historical period and FTEs for the future) make comparison and trending of staffing levels difficult. The Board must be able to see proposed staffing levels and compare those to previous period actuals. The Board therefore will direct OPG to file on a FTE basis in its next application and to restate historical years on that basis.

One of the reasons for the discontinuity between headcount and FTEs may be the extensive use of overtime, particularly in the nuclear division. The Board expects to examine the issue of overtime more closely in the next proceeding. The Board expects OPG to demonstrate that it has optimized the mix of potential staffing resources.

Despite this difficulty in comparing proposed staffing levels with past periods, the Board is of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity. This was demonstrated by OPG's own evidence, as explained by OPG's witness and by Mr. Sequeira from ScottMadden, with respect to the Radiation Protection Function.[38]

The ScottMadden Phase 2 report observed that OPG's staffing levels per unit exceed both the industry median and Bruce Power, and that OPG staff levels are generally higher than the comparison panels (while noting that this may be influenced by OPG's

[37] Decision with Reasons, EB-2006-0501, August 16, 2007, p. 33.
[38] Tr. Vol. 3, p. 24.

practice of contracting out relatively few project based outage functions).[39] For this reason, the Board has also directed OPG to conduct a staff level analysis as part of its benchmarking studies for the next proceeding. (This issue is discussed more fully in Section 4.2, Benchmarking.) ScottMadden also conducted a pilot top-down staffing analysis for a single OPG function: the Radiation Protection Function. ScottMadden concluded that there was room for a potential reduction of 48 FTEs (28%) in the Radiation Protection Function, of which 13 FTEs could be eliminated altogether. Despite these findings, OPG failed to act on an opportunity to eliminate 13 FTEs, and instead eliminated only one.[40] This is only a single example concerning relatively few positions, but the Board is concerned that OPG has not acted more aggressively in a case where it has clear information that a particular function is overstaffed. Although collective agreements may make it difficult to eliminate positions quickly, it is not reasonable for ratepayers to bear these additional costs in the face of strong evidence that the positions are in excess of reasonable requirements. With 20 to 25% of staff expected to retire between 2010 and 2014, the Board concludes that OPG has a timely opportunity to review its organizational structure, taking actions to reassign functions and eliminate positions. The Board is not suggesting that a specific percentage of the retiring staff will not need to be replaced, but this may provide an opportunity for reducing the overall staffing complement without disrupting negotiated commitments with the unions.

As to the compensation, the Board finds that the compensation benchmark should generally be set at the 50th percentile. OPG suggests there is no evidence to support this conclusion, but the Board disagrees. This target level is consistent with the recommendations of the Agency Review Panel for executive employees, and indeed for management employees, OPG uses the 50th percentile as the benchmark. In the Board's view, there would need to be strong evidence to conclude that a higher percentile is warranted for non-management staff. OPG provided no such compelling evidence, but merely asserted that positions in the nuclear business required greater skills overall than the comparators. There was no documentation or analysis to support these assertions.

The evidence provided does not substantiate the assertion that the positions selected by OPG are sufficiently different to warrant the use of the 75th percentile. Although OPG stressed that its work requirements (particularly on the nuclear side) are highly

[39] Exh. F5-1-2, p. 26.
[40] Tr. Vol. 3, p. 27.

technical, the Board observes that many of the comparators in the Towers Perrin study would also require highly technical skills, and some of the comparators also operate nuclear facilities. Indeed the job classifications used in the Towers Perrin report are compared against each other on the basis that they are at least broadly speaking comparable. A number of the positions selected by OPG, such as labourer, also do not appear to be specifically related to highly technical nuclear plant work. In addition, most of the comparators were similarly large and unionized, and perform highly technical, though not necessarily nuclear plant, work. The Board recognizes that the analysis conducted by OPG to produce the chart is not comprehensive, and indeed was not likely intended to be comprehensive. Well over half of OPG's employees are not covered by the 30 positions listed in the chart. The data was not specifically prepared for the purpose of conducting a comprehensive comparison, and the data used in preparing the chart references base salary only.[41] Despite these limitations, the analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons.

PWU argued that the comparative analysis, which uses non-nuclear entities, is not evidence of imprudence by OPG, and therefore there is no evidence to rebut the presumption that the expenses arising from the collective agreements are prudent. The Board does not agree.

The ratepayers should only be required to bear reasonable costs – and in determining reasonable costs the Board can be guided by market comparisons. It is the responsibility of the Board to send a clear signal that OPG must take responsibility for improving its performance. In order to achieve this, the Board will reduce the allowance for nuclear compensation costs by $55 million in 2011. This amount is derived by considering a number of factors:

- Reducing the compensation for the 30 positions from the Towers Perrin data would require a reduction of $37.7 million.
- Given the breadth of positions in the analysis and the prevailing pattern that wages are well in excess of the 50th percentile, it is reasonable to conclude that the same pattern exists for the vast majority of all staff positions in the company. There was certainly no evidence to suggest otherwise. Therefore, the total

[41] The Towers Perrin survey was filed confidentially with the Board as undertaking J8.5. The Towers Perrin Survey includes data both for base salary and total cash compensation. However, OPG appears to have used only the base salary information in preparing the chart. See Tr. Vol. 8, pp. 175-176.

adjustment to move all regulated staff to the 50th percentile is substantially in excess of $37.7 million.

- In determining the appropriate adjustment, the Board recognizes that it will be difficult for OPG to make significant savings through compensation levels alone in the short to medium-term given the collective agreements with its unions.
- OPG has already indicated that there will be no increase in management salaries through April 1, 2012, and this reduction was not incorporated into the original filing.
- The ScottMadden benchmarking analysis supports the conclusion that there is excess staff overall and that this is one component of OPG's relatively poor performance (in comparison to its peers). A further reduction in the allowance for compensation is warranted for this factor.
- The ScottMadden benchmarking analysis also demonstrates that OPG's overall performance is poor on certain key benchmarks, for example non-fuel operating costs. Compensation is a significant cost driver for this metric, and OPG's poor ranking supports the Board's decision to make reductions on account of compensation costs

The same reduction will apply in 2012, but there will also be an additional reduction of $35 million to represent further progress toward the 50th percentile, further progress in reducing excess headcount, and further progress toward achieving a reasonable level of cost performance. The total reduction for 2012 is $90 million.

While a more aggressive reduction was argued by some intervenors, the Board recognizes that changes to union contracts, to staffing levels and movement to the 50th percentile benchmark will take time. Indeed, the Board recognizes that OPG may not be able to achieve $145 million in savings in the test period through compensation reductions alone. The Board is making these adjustments so that payment amounts are based on a reasonable level of performance. If costs are in excess of a reasonable level of performance, then those excess costs are appropriately borne by the shareholder.

The Board is allocating this adjustment solely to the nuclear business for the purposes of setting the payment amounts. The Board is not ordering any reductions for the hydroelectric business because the benchmarking evidence for that business supports the conclusion that it is operated reasonably efficiently from an overall perspective, and therefore the Board is less concerned with the specific compensation levels for that part of the company. For the nuclear business the evidence is clear that overall performance is poor in comparison to its peers and the staffing levels and compensation exceed the comparators. On this basis an adjustment is necessary to ensure the payment amounts are just and reasonable.

Lastly, the Board directs OPG to conduct an independent compensation study to be filed with the next application. As noted above, OPG's compensation benchmarking analysis to date has not been comprehensive. The Board remains concerned about compensation costs, in light of the company's overall poor nuclear performance, and would be assisted by a comprehensive benchmarking study comparing OPG's total compensation with broadly comparable organizations. The study should cover a significant proportion of its positions. Compensation costs are a signification proportion of the total revenue requirement; OPG's position that such a study would be too expensive and of little value is therefore not reasonable. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised. The costs of the study are to be absorbed within the overall revenue requirement allowed for in this Decision. This has been already accounted for in the Regulatory Affairs budget, which anticipates studies in support of the company's next application.

6.2 Pension and Other Post Employment Benefits

Costs related to Pension and Other Post Employment Benefits ("OPEB") for the test period were forecast based on discount rates and assumptions in OPG's 2010-2014 business plan. The total amount requested for the test period is approximately $633 million. On September 30, 2010, OPG filed an Impact Statement in which it identified a significant decline in discount rates causing an increase in forecast pension and OPEB costs for the test period. Rather than revising the proposed revenue requirement, OPG requested approval for a variance account, "to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs." The total forecast increase as a result of the update is $264.2 million, as summarized in the following table.

Table 18: Updated Pension and OPEB Costs ($ million)

	Nuclear		Regulated Hydroelectric	
	2011	2012	2011	2012
Pension Cost				
As per Chart 9, Exh.F4-3-1	$114.0	$162.8	$5.8	$8.1
Projection as of August 2010	210.2	245.9	10.6	12.3
Increase	96.2	83.1	4.8	4.2
OPEB Cost[1]				
As per Chart 9, Exh.F4-3-1	159.3	166.7	8.0	8.3
Projection as of August 2010	196.5	201.7	9.9	10.1
Increase	37.2	35.0	1.9	1.8
Total Test Period Increase		**$251.5**		**$12.7**

Note 1: Supplementary pension plans costs are included with OPEB costs
Source: Exh. N-1-1

Board staff submitted that it would be more appropriate for OPG to determine pension and OPEB costs on a cash basis because costs determined on that basis are more stable for ratemaking purposes than those calculated on an accounting basis. In support of its position, Board staff provided a table in its submission that illustrated pension and OPEB payments on an accounting basis as well as a cash basis. On a cash basis, the table identified a total amount of $568 million. This position was supported by CCC, CME, and SEC.

In reply, OPG noted that the Board had approved the accrual method in the previous case and argued that no evidence had been introduced on the cash method in the current proceeding. OPG pointed out that the Board staff tables did not reflect updated pension contributions for 2011 and 2012, as provided by Mercer. OPG maintained that including the updates demonstrates that the cash basis is no more stable than the accounting basis. As noted in OPG's reply submission, there are utilities regulated by the Board using the cash basis and others using the accounting basis.

Board staff further submitted that the variance account request should be denied, and its position was supported by CCC, CME, SEC and VECC. Board staff raised two materiality arguments in its submission. Staff noted that OPG had not informed its shareholder of the increased forecast cost as OPG suggested the increase was not material, and that balances in the Hydro One transmission pension variance account for the last two proceedings have not been material. On the first point, OPG replied that seeking shareholder approval before applying for a variance account is not an established requirement. On the second point, OPG maintained that there is no evidence that OPG's variances will be similar to the immaterial balances recorded by Hydro One.

VECC submitted that the Hydro One pension and OPEB variance accounts for its distribution business and its transmission business were established under specific and unique circumstances and should not be accepted as precedents by the Board. VECC maintained that the accounts are "not the result of decisions wherein the Board actually turns its mind to the appropriateness of allowing HONI to be fully protected from the risk associated with its pension cost forecasts."[42] OPG challenged this view and argued that the Hydro One decision confirmed that balances in the variance account would be subject to a prudence review.

In the previous proceeding the Board denied OPG's request for a pension and OPEB variance account. Board staff submitted that had the account been approved, an estimated $314 million credit to ratepayers would have been recorded for the period 2008 to 2010. This led staff to conclude that the request in the current proceeding should be denied because the pension and OPEB amounts included in the current application are lower than what OPG now believes it will incur in the test period. OPG responded that staff's conclusion amounts to retroactive ratemaking and further, that the staff analysis is not correct. Staff's analysis reflects a full year for 2008, but in OPG's view should reflect only 9 months. OPG also argued that staff has grossly overestimated the 2010 variance.

OPG also disagreed with the Board staff submission on pension and OPEB in three other areas:

- Board staff submitted that if the Board allows OPG to collect the forecast accounting OPEB costs, the variance should be placed in a segregated fund. OPG doubted whether the Board has jurisdiction to implement the proposal. SEC also disagreed with staff, expressing its concern with the precedent;
- Staff submitted that the undisclosed tax impact related to the amount to be tracked in the variance account is approximately $91 million. OPG responded that Board staff is incorrect in submitting that the consequences of taxes

[42] VECC Argument, para. 134.

regarding the update have not been identified, citing updates to the pre-filed evidence; and

- Board staff submitted that OPG should provide evidence that discusses alternatives to AA bond yields to forecast discount rates. In reply, OPG cited sections of the CICA handbook and asserted that the use of AA bond yields was appropriate.

Board Findings

OPG correctly points out that there is currently no consistency amongst utilities in the use of either the cash or accrual method to setting pension and other post employment benefit expenses. Both methodologies have been approved by the Board. The Board in this case sees no compelling reason to change OPG's existing approach of using the accrual method. Consistency in accounting treatment, in order to compare results year to year, is advantageous for purposes of assessing the level of costs for reasonableness. A consistent approach over time also ensures a greater level of fairness for ratepayers and the company.

The request for a variance account is denied. Pension and OPEB costs should be included in the forecast of expenses in the same way as other OM&A expenses, and then managed by the company within its overall operations. The Board finds that the forecast included in the pre-filed evidence was more rigorous because it was based on a set of internally consistent assumptions, while the update is based on the AA bond yields which will change. Accordingly, the Board finds that the allowance for pension and OPEB expenses in the pre-filed evidence is appropriate, as it is the best evidence on this matter.

The Board is reluctant to make selective updates to the evidence. The bond yields have changed, and will continue to change, as noted by the actuary in the updated statement. Further, the Board notes that the financial market conditions are variable and have indeed improved since the impact statement was filed. The Board concludes that an adjustment to the allowance is not warranted.

The Board sees no reason to depart from the use of AA bond yields at this time, with the exception of using more current data. However, OPG is directed to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rates in its next application.

6.3 Centralized Support and Administrative Costs

Centralized Support and Administrative Costs include Corporate Support and Administrative Service Groups ("Corporate Support"), Centrally Held Costs and Hydroelectric Common Services that are related to the operation of OPG's business units. The costs are assigned/allocated to OPG's regulated and non-regulated businesses. The Centralized Support and Administrative Costs budget assigned/allocated to the regulated hydroelectric business totals $57.5 million in 2011 and $60.9 million in 2012. The amount assigned/allocated to the nuclear business totals $448.1 million for 2011 and $486.6 million for 2012. Details are set out in the following table.

Table 19: Allocation - Centralized Support and Administrative Costs

($ million)	2011 Plan	2012 Plan
Hydroelectric		
Corporate Support	$24.7	$26.1
Centrally Held	22.9	25.5
Common Hydroelectric	9.9	9.3
Total	57.5	60.9
Nuclear		
Corporate Support	249.1	252.3
Centrally Held	199.0	234.3
Total	**$448.1**	**$486.6**

Source: Exh. L-1-90, Exh. F3-1-1, Tables 2 and 3, Exh. F4-4-1, Tables 2 and 3

6.3.1 Corporate Support Costs

Corporate Support service group activities include Real Estate, Energy Markets, Business Services, IT, Finance, Corporate and Executive Services (Public Affairs, Regulatory/Strategic Planning, Emergency Preparedness, Law) and Human Resources. For these services OPG seeks approval for $24.8 million in 2011 and $26.3 million in 2012 for the regulated hydroelectric business, and $249.2 million in 2011 and $252.3 million in 2012 for the nuclear business. The budgeted and actual amounts for the years 2007 to 2012 are set out in the following table.

Table 20: Allocated Corporate Support Costs

($ million)	2007 Budget	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Hydroelectric	$23.3	$21.9	$28.3	$26.3	$28.9	$24.9	$25.1	$24.8	$26.3
Nuclear	$250.5	$240.7	$269.1	$237.6	$267.4	$234.5	$247.0	$249.0	$252.3

Source: Exh. F3-1-2, Tables 1 and 2

OPG filed two corporate function benchmark reports, one on Human Resources and the other on Finance. No submissions were filed on these reports.

In response to direction in the previous payment amounts decision, OPG retained Black & Veatch to review the cost allocation methodology with respect to the Board's three prong test (cost incurrence, cost allocation and cost/benefit). Black & Veatch concluded that OPG's cost allocation methodology meets current best practices and meets all aspects of the three prong test. No submissions were filed on corporate cost allocation.

Board staff commented on the Regulatory Affairs component of the Corporate Support costs. Board staff submitted that the Regulatory Affairs budget should be reduced by $2.238 million in 2011 and by $1.908 million in 2012. The Board staff submission was based on comparisons with 2008 actuals as a benchmark rate case year and 2009 actuals as a benchmark non-rate case year. Staff also submitted that there was no basis for the forecast increase in the Board's annual assessment. Board staff's position was supported by SEC and VECC and referenced by CCC in its submission.

OPG responded that the Board should reject Board staff's proposed cuts because they are based on faulty premises. OPG maintained that the 2008 Regulatory Affairs costs do not reflect all the costs related to the last application, as substantial costs were incurred and recorded in 2007. OPG also argued that the previous case is not a proxy for future proceedings because more work from other business units has shifted to Regulatory Affairs and the effort related to applications has increased. OPG noted that the next application will involve substantial issues, for example, IFRS and the Niagara Tunnel, and any studies directed by the Board in this proceeding. OPG also noted that in 2011 substantial resources will be required to assess incentive mechanisms, including stakeholder consultations. OPG also pointed out that the Regulatory Affairs budget includes costs for OPG's participation in the upcoming IPSP, IESO market rules development and OPG's strategic planning process.

CCC made submissions on the overall Corporate Support costs, arguing that they should be reduced because the costs appear discretionary at some level and there is a pattern of actual costs coming in below forecast. CCC submitted that the hydroelectric business costs should be reduced by the average of the variances over the three year period, amounting to a $2.46 million reduction for the hydroelectric allocation and a $24.7 million reduction to the nuclear business allocation.

OPG took issue with CCC's premise that OPG's historical under spending in Corporate Support warrants a cut to the amounts requested for the test period. OPG pointed to the variance explanations found in the evidence, which included the impact of Information Technology Special Initiatives, lower New Horizon System Solutions outsourcing agreement gainshare, deferrals such as the 2010 rate application, decreased advertising, one-time IT credit adjustments, and the management of staff vacancies. OPG noted that as a result of its cost control initiatives, the increase in allocated support costs in the test period is 1.2% annually, much less than the rate of inflation and expected growth.

Board Findings

The Board accepts OPG's evidence on the benchmarking studies and the cost allocation methodology.

OPG has provided credible evidence for the increase in the Regulatory Affairs costs. Accordingly, the Board will not direct any specific reduction to the Regulatory Affairs test period forecast.

The Board agrees with the submissions of CCC that there has been a history of under spending in the Corporate Support function and, in fact, the amount of under spending has been increasing from 2007 to 2009. The Board expects the cost savings impact of the efficiency improvement initiatives undertaken by OPG to be reflected in the company's forecasted budgets. History indicates that this has not been the case. However, for this test case period, the proposed budget is not unreasonable given 2009 actual spend and the 2010 budget. In addition, the Board's decision on compensation may affect total corporate support costs. For these reasons the Board will make no further adjustments to the budget.

6.3.2 Centrally Held Costs

Historic and forecast of test period centrally held costs are summarized in the following table.

Table 21: Centrally Held Costs ($ million)

Corporate Costs	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Pension/OPEB Related Costs (1)	$178.8	$116.7	$(27.7)	$118.5	$145.4	$213.1
OPG-Wide Insurance	19.1	16.3	17.0	16.9	17.4	18.0
Nuclear Insurance	7.6	7.8	7.3	8.6	11.3	13.4
Performance Incentives	40.8	45.3	40.3	45.8	46.2	46.7
IESO Non-Energy Charges	20.5	22.4	75.5	54.7	62.8	69.2
SR&ED Investment Tax Credits	0.0	(30.0)	(22.1)	(10.0)	(10.0)	(10.0)
Other	31.1	25.0	31.4	26.4	28.1	(1.4)
TOTAL	**$297.9**	**$203.5**	**$121.7**	**$260.9**	**$301.2**	**$349.0**

Note 1: Excludes current service costs included in compensation Table 17
Source: Exh. F4-4-1, Table 1

Similar to the corporate support costs, Black & Veatch reviewed the allocation of centrally held costs and came to the same conclusions.

Submissions were filed on pension and OPEB related costs, IESO non-energy charges, and nuclear insurance. Pension and OPEB costs are addressed earlier in this chapter, and IESO non-energy charges are addressed in Chapter 10. Nuclear insurance costs are addressed here.

Board staff submitted that the proposed increase in nuclear insurance costs should not be included in the revenue requirement, because the increase is based on federal government requirements which are in a proposed bill at the second reading stage. Similar bills have been introduced by the federal government numerous times in the past but all have failed to receive Royal Assent. SEC similarly submitted that it is premature to assume that nuclear insurance costs will increase and the appropriate cost level to use is the average for the last four years, $7.8 million per year.

OPG responded that it is appropriate and prudent to include the forecast nuclear insurance costs based on the proposed legislation. OPG establishes an operating budget through the annual business planning process, and it must operate within this budget. OPG stated that the timing related to the increase in nuclear insurance costs is uncertain, but that the forecast represents OPG's best estimate.

Board Findings

The Board agrees it is premature to increase nuclear insurance costs because of a bill that is still being debated by the federal government. The Board will reduce the 2011 proposed amount for nuclear insurance costs by $2.5 million, resulting in $8.8 million for 2011. This was obtained by taking the 2010 budget for nuclear insurance costs and increasing for inflation. The amount to be included for 2012 is $9 million.

6.4 Depreciation

OPG seeks approval for depreciation and amortization expense of $130.6 million for the regulated hydroelectric facilities and $491.8 million for the nuclear facilities for the test period. The nuclear station end of life assumption impacts on depreciation expense are discussed in Chapter 8.

OPG's internal Depreciation Review Committee ("DRC") is accountable for providing engineering, technical and financial review of asset service lives. Board staff observed that the 2009 DRC report showed a trend of increases to the useful lives of many nuclear assets resulting in annual reductions to depreciation expense starting in 2010. Board staff argued that OPG's depreciation expense may be overstated as the DRC has not completed its review of all nuclear assets, and the trend of increasing useful life is likely applicable. Board staff also submitted that the Board should direct OPG to file an independent depreciation study for its regulated facilities and the Bruce stations. Board staff noted that the Board has required this filing for other large utilities. SEC supported the staff submission.

OPG responded that the nuclear assets that have not been reviewed by the DRC are of a different nature and that it is unlikely that their service lives would be increased. OPG also pointed out that the majority of OPG's nuclear asset class lives are capped by assumptions for life limiting components for station life even if the asset could last longer.

OPG argued that an independent depreciation study would increase costs without providing value. While comparative data is likely available for hydroelectric assets, OPG argued that an independent consultant would have to rely on OPG's expertise for nuclear assets. OPG also referred to the Ganett Fleming report on OPG's depreciation review process which was filed in the previous proceeding. OPG stated that the report concluded that OPG's DRC process was adequate and did not burden the ratepayer with the cost of new systems or processes.

Board Findings

As discussed elsewhere in this Decision, the Board has accepted the end of service life estimates for the prescribed facilities as filed by OPG, including the extended service life for Darlington. No other issues were raised with respect to the depreciation expense for the test period.

The Board is satisfied with OPG's approach for the test period and notes that no concerns were raised with respect to the upward revisions related to the assets reviewed by the DRC. The Board further accepts OPG's explanation regarding the assets which were not reviewed and concludes that there is no evidence to indicate that OPG's depreciation levels are unreasonable for the test year. The Board will, however, direct OPG to file an independent depreciation study at the next proceeding. While the Ganett Fleming report commented on the process being followed it is important to also have an independent assessment of the assets. As noted in several submissions, an independent study is a typical requirement of utilities, conducted periodically. Given the level of depreciation expense involved, the Board concludes there is merit in OPG also providing such a study. Such a study provides assurance to the Board and all parties that the depreciation and amortization expenses, which are significant, are reasonable.

6.5 Taxes

OPG uses the taxes payable method for determining regulatory income tax of the prescribed facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of test period income tax expense of $58.0 million and $129.8 million for the regulated hydroelectric and nuclear facilities respectively.

SEC submitted that tax deductions taken by OPG prior to April 1, 2008, amounting to $1,660.4 million, should be available for deduction by ratepayers and that there should be no regulatory tax liability for the test period. This matter is discussed in the tax loss variance account section in Chapter 10.

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 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.

Board staff and SEC submitted that the revenue requirement impact of the HST input tax credits is a reduction of $6.0 million per annum, not the amount of $5.0 million included in the application.

In reply, OPG stated that the $6.0 million estimate is only based on 3 months of data which is unlikely to be representative. OPG also stated that HST is not a discrete entry, but forms part of the expenditure on underlying items. Further, OPG stated that increases in HST savings only occur as a result of increases in underlying costs attracting the tax.

Staff submitted that OPG should report back to the Board in its next application with details of twelve months of HST returns and the input tax credit ("ITC") amounts related to the prescribed facilities. OPG replied that the information may not be meaningful because the ITC amounts do not necessarily correspond to HST savings. OPG also noted that producing such a report was resource intensive, and that the results would be corporate based and need to be allocated to the prescribed facilities.

Board Findings

The Board accepts OPG's evidence with respect to HST. There was little substantial evidence to support the changes proposed by Board staff and the suggested differences are well below the materiality threshold. The Board therefore accepts OPG's evidence as being reasonable. The Board will not direct OPG to provide details regarding its HST returns. The Board will however expect OPG to continue to demonstrate that the impacts of HST have been appropriately incorporated into its forecasts.

7 BRUCE LEASE – REVENUES AND COSTS

OPG leases the Bruce A and Bruce B generating stations and associated lands and facilities to Bruce Power. Sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the Board shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations, and that any revenues it earns from the Bruce Lease in excess of costs will be used to offset the nuclear payment amounts.

The decision of the previous payment amounts proceeding found that the Bruce generating stations should not be treated as if they were regulated facilities. OPG was directed to calculate all Bruce revenues and costs in accordance with GAAP for non-regulated businesses.

Bruce revenues are derived from base and supplemental payments as set out in the Bruce Lease, used fuel storage and long term disposal services, low and intermediate waste management services, and support and maintenance services as set out in the Bruce Site Services Agreement. Costs include depreciation, which includes asset retirement costs, taxes, accretion, earnings/losses on nuclear segregated funds, the cost of used fuel storage and disposal, and the cost of waste management.

Black & Veatch reviewed OPG's methodology for assigning and allocating revenue and cost to the Bruce facilities and under the Bruce Lease. Black & Veatch found the methodology to be appropriate and compliant with the Board's decision in the previous proceeding.

The Bruce Lease net revenues are forecast to be $128.1 million in 2011 and $143.0 million in 2012, as shown in the table below. If approved, these amounts would offset the nuclear revenue requirement.

Table 22: Bruce Lease Forecast Revenues and Costs

($ million)	2011 Plan	2012 Plan
Bruce Lease Revenues	$254.4	$268.7
Bruce Lease Costs		
Depreciation	34.5	34.5
Property Tax	13.6	14.1
Capital Tax	0.0	0.0
Accretion	294.5	307.2
(Earnings) Losses on Segregated Funds	(286.2)	(304.6)
Used Fuel Storage and Disposal	17.0	24.0
Waste Management Variable Expenses	0.8	0.7
Interest	11.9	6.9
Total Costs Before Income Tax	86.1	82.8
Income Tax – Current	0.0	8.6
Income Tax - Future	40.2	34.3
Total Bruce Lease Costs	126.3	125.7
Bruce Lease Net Revenues	**$128.1**	**$143.0**

Source: Exh. G2-2-1, Tables 1 and 5

Forecast amounts will be tracked against actual revenues and costs, and the variances will be recorded in the Bruce Lease Net Revenues Variance Account, which was established in the previous proceeding. Submissions related to the variance account can be found at Chapter 10.

The only issue raised with respect to the Bruce Lease was related to the impact on nuclear liability costs as a result of the Darlington Refurbishment Project and the new end of life date for Darlington. GEC submitted that the changes to the Bruce Lease costs that result from the 2051 end of life date for Darlington are not appropriate at this time. OPG replied that its application is consistent with GAAP accounting information as reflected in its audited financial statements. The Board's findings with respect to the Darlington Refurbishment Project can be found at Chapter 5 and the findings with respect to station end of life can be found at Chapter 8.

Board Findings

The Board approves OPG's test period forecast for the Bruce Lease net revenues. The Board finds that OPG has estimated the revenue and costs associated with the Bruce generating station in accordance with the methodology established by the Board in the previous proceeding, including the impact arising from the change in the end of life date for Darlington.

8 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

OPG incurs liabilities related to decommissioning its nuclear stations (including Bruce), nuclear used fuel, and low and intermediate level waste management (collectively "nuclear liabilities" or "asset retirement obligations"). The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement ("ONFA"). ONFA provides for the establishment of a reference plan for nuclear liabilities which must be updated every 5 years. The current reference plan was updated in November 2006.

8.1 Methodology

The ratemaking treatment for nuclear liabilities is complex and was a matter of considerable discussion in the previous proceeding. In the previous decision, the Board approved a methodology for the recovery of nuclear liabilities that recognized a return on rate base associated with asset retirement costs ("ARC") for Pickering and Darlington. The methodology required that the return on the ARC be limited to the weighted average accretion rate, which was 5.6 % at that time. It is now 5.58%. The portion of the rate base to which the accretion rate applies is equal to the lesser of (a) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (b) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington.

Other costs associated with nuclear liabilities approved for recovery are the annual depreciation and amortization expenses associated with the ARC, and the variable expenses for the nuclear waste generated each year including expenses relating to low and intermediate level waste.

The Board approved a GAAP basis of accounting for determining the net revenue impact of nuclear liabilities associated with the Bruce facilities. Under this approach, the lease revenues and all cost items are recognized in accordance with GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities are included as a reduction of costs and an income tax (PILS) provision is calculated in accordance with GAAP.

OPG proposed to maintain the revenue requirement treatment for nuclear liabilities for Pickering, Darlington and the Bruce facilities which was approved in the previous proceeding.

In the previous decision the Board found that if there were external developments related to the ratemaking aspects of asset retirement obligations, parties could submit evidence and argue for alternative treatment in OPG's next hearing. In this application, OPG indicated that it would continue to investigate the impacts of the approved revenue requirement treatment on its ability to fully recover its nuclear liabilities, and that it may propose modifications to the existing treatment or an alternative treatment in a future application.

OPG stated that it monitors emerging issues with respect to methodologies for the recovery of asset retirement obligations across North America as part of its regular business activities. With the exception of the National Energy Board's ("NEB") review related to pipeline abandonment, OPG was not aware of any policy positions, papers or decisions related to the methodology for recovering asset retirement obligations that have been issued since the last proceeding. The NEB's ongoing review related to pipeline abandonment will examine the methodology for recovering asset retirement obligations. The company's position was that as that review was not yet complete, it would be premature to change OPG's approach at this time. CME agreed with OPG.

Board Findings

The Board agrees with OPG and CME that it would be premature to revise the existing methodology for the regulatory treatment of nuclear liabilities. The only relevant external development brought to the Board's attention is the NEB review and it is not yet complete. If the results of the NEB review, or any other external development, suggest a change in the Board's methodology may be warranted, the Board will revisit the issue in the next application.

The Board accepts the methodology used by OPG to calculate the revenue requirement impacts of OPG's nuclear liabilities.

8.2 Station End of Life Dates and Test Year Nuclear Liabilities

The following table shows the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities and the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. OPG calculated the return on rate base on the lesser of these two amounts using the average accretion rate of OPG's nuclear liabilities, which is 5.58% for the test period.

Table 23: Prescribed Facilities - Lesser of Asset Retirement Costs or Unfunded Nuclear Liability ($ million) Subject to Return Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
	ASSET RETIREMENT OBLIGATION (ARO)					
1	Adjusted Opening Balance	$5,921.0	$6,151.2	$6,888.6	$7,136.8	$7,432.8
2	Closing Balance	6,151.2	6,391.2	7,136.8	7,432.8	7,748.0
3	Average Asset Retirement Obligation ((line 1 + line 2)/2)	6,036.1	6,271.2	7,012.7	7,284.8	7,590.4
	NUCLEAR SEGREGATED FUNDS BALANCE					
4	Adjusted Opening Balance	4,829.9	4,584.2	5,058.7	5,399.6	5,778.5
5	Closing Balance	4,584.2	5,058.7	5,399.6	5,778.5	6,160.7
6	Average Nuclear Segregated Funds Balance ((line 4 + line 5)/2)	4,707.0	4,821.5	5,229.2	5,589.1	5,969.6
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)					
7	Adjusted Opening Balance (line 1 - line 4)	1,091.1	1,567.0	1,829.9	1,737.2	1,654.3
8	Closing Balance (line 2 - line 5)	1,567.0	1,332.5	1,737.2	1,654.3	1,587.3
9	Average Unfunded Nuclear Liability Balance ((line 7 + line 8)/2)	1,329.1	1,449.7	1,783.5	1,695.7	1,620.8
	ASSET RETIREMENT COSTS (ARC)					
10	Adjusted Opening Balance	1,345.7	1,221.7	1,573.1	1,539.9	1,506.7
11	Closing Balance	1,221.7	1,098.0	1,539.9	1,506.7	1,473.5
12	Average Asset Retirement Costs ((line 10 + line 11)/2)	1,283.7	1,159.8	1,556.5	1,523.3	1,490.1
13	**LESSER OF AVERAGE UNL OR ARC**	**$1,283.7**	**$1,159.8**	**$1,556.5**	**$1,523.3**	**$1,490.1**

Note: The 2010 adjusted opening balances for ARO and ARC include increases of $497.4 million and $475.2 million respectively for recognition of the Darlington Refurbishment Project.

Source: Exh. C2-1-2, Table 1

The test period revenue requirement impact of nuclear liabilities is $291.3 million for Pickering and Darlington and $110.3 million for the Bruce facilities. The following table summarizes historic and test period revenue requirement impacts.

Table 24: Revenue Requirement Impact of OPG's Nuclear Liabilities ($ million)

Line No.	Description	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
	PRESCRIBED FACILITIES					
1	Depreciation of Asset Retirement Costs	$124.0	$123.8	$33.2	$33.2	$33.2
2	Used Fuel Storage & Disposal Variable Expenses	19.0	19.2	23.0	26.6	28.5
3	Low & Intermediate Level Waste Management Variable Expenses	1.7	3.5	1.1	0.8	0.8
	Return on Rate Base:					
4	Accretion Rate	53.9	65.0	86.9	85.0	83.1
5	Weighted Average Cost of Capital	17.8	0.0	0.0	0.0	0.0
6	**Total Revenue Requirement Impact**	**$216.4**	**$211.5**	**$144.2**	**$145.7**	**$145.6**
	(line 1 + line 2 + line 3 + line 4 + line 5)					
	BRUCE FACILITIES					
7	Depreciation of Asset Retirement Costs	$48.6	$48.5	$28.5	$28.5	$28.5
8	Used Fuel Storage & Disposal Variable Expenses	14.0	14.4	16.7	17.0	24.0
9	Low & Intermediate Level Waste Management Variable Expenses	11.2	4.4	0.9	0.8	0.7
10	Accretion	200.6	279.3	282.4	294.5	307.2
11	Less: Segregated Fund Earnings (Losses)	(138.0)	386.2	268.8	286.2	304.6
12	Return on Rate Base	15.4	0.0	0.0	0.0	0.0
13	**Total Revenue Requirement Impact**	**$427.6**	**$(39.5)**	**$59.6**	**$54.5**	**$55.8**
	(line 7 + line 8 + line 10 - line 11 + line 12)					

Source: Exh. C2-1-2, Table 5

The revenue requirement impact of the nuclear liabilities for the prescribed facilities decreases significantly in the period 2010-2012 as a result of OPG's decision to move to the definition phase of the DRP. The consequential impacts of the decision to proceed with the definition phase of the DRP are discussed in Chapter 5.

There was considerable examination in the proceeding of the effect of station end of life dates on the revenue requirement impacts of nuclear liabilities.

As noted in Chapter 5, OPG has assumed an end of life of 2051 for Darlington. The impacts of that decision on revenue requirement are discussed there, as is the Board's acceptance of that decision for rate-making purposes.

In addition, several issues were raised in relation to the appropriateness of the end of service life dates for Pickering A and Pickering B nuclear stations. For accounting and depreciation purposes, the end of service life date for Pickering B is September 30, 2014 and for Pickering A (units 1 and 4) it is December 31, 2021. OPG did not change the end of service life of the Pickering B station, even though the company is currently undertaking work designed to extend the life of two units to 2018 and the other two units to 2020. In addition, without the continued operations of Pickering B, the evidence is that it would be quite unlikely that Pickering A would continue operations because the two stations are operationally and economically interdependent. In summary, the station end of life dates are chosen on the basis of the level of certainty which exists regarding the DRP and the Pickering B Continued Operations project. OPG has a high level of confidence regarding the DRP and only a medium level of confidence regarding the Pickering B project.

All station end of life dates were recommended by OPG's Depreciation Review Committee ("DRC") in its 2009 report and approved by OPG senior management to be effective on January 1, 2010.

The station end of life dates affect the valuation of the asset retirement obligations and consequently ARC. Specifically, the decision to proceed with the DRP changes the valuation of the nuclear used fuel and decommissioning liabilities and the ARC for the prescribed facilities and the Bruce facilities. The changes in the asset retirement obligations and the ARC result in revenue requirement changes related to the return on rate base, depreciation expense, used fuel storage and disposal variable expense and income taxes for the prescribed facilities. For the Bruce facilities, the revenue requirement is impacted by changes to depreciation expense, accretion expense, used fuel storage and disposal variable expense and income taxes.

As noted in the DRP section of this Decision, the revenue requirement impact of the DRP is a considerable. The most significant contributor is a reduction in depreciation expense of $229.6 million arising from Darlington's asset retirement costs and the extension of service life impacts. Essentially, the obligations related to decommissioning the stations and dealing with the used fuel are pushed further into the future, thereby reducing the revenue requirement in the current period. These revenue requirement reductions are offset to some extent by the increased amount of used fuel.

OPG asserted that the accounting changes it has implemented to reflect the DRP and an end of life of 2051 are based on its accounting rules which are in accordance with GAAP. Some parties suggested that for regulatory accounting purposes, the end of station life for Darlington could remain at 2019.

As noted in the DRP chapter, there was considerable discussion about the scope of the Board's approval of the DRP. SEC cross-examined OPG on the connection between the scope of the Board's approval of the DRP and OPG's application with respect to depreciation and nuclear liabilities.

> MR. REEVE: There was a discussion around the approval of the Darlington refurbishment project; that's correct.
> MR. SHEPHERD: And you are not asking for approval of that. But I am right, am I not, that the depreciation expense and the asset retirement expense in the current application for Darlington assume that Darlington will be refurbished?
> MR. REEVE: That's correct.
> MR. SHEPHERD: And so if this Board approves the depreciation expense and the asset retirement expense – or, sorry, the decommissioning expense, it is on the assumption that Darlington refurbishment will take place?
> MR. REEVE: From an accounting standpoint, yes.[43]

Parties also queried OPG's decision to delay its determination as to whether to extend the station life of Pickering B under the Continued Operations project until 2012, and the dependence of Pickering A operations on Pickering B operations. OPG stated that it does not plan to operate the two units at Pickering A if Pickering B were to be closed in 2014 as this would result in significant technical and economic challenges to operate Pickering A alone.

OPG argued that its evidence is consistent with GAAP. With respect to Pickering B, OPG explained that it does not revise station end of life dates for depreciation purposes until it has a high degree of confidence in revised service life dates. As noted in the section of this decision on DRP, OPG stated that its Board of Directors has decided to proceed with the DRP by moving into the definition phase, and that the Province has

[43] Tr, Vol. 10, p. 102.

concurred with this decision. The internal DRC has high confidence that the refurbishment will proceed and hence recommended the Darlington end of life date of 2051.

OPG was asked to recalculate the impacts on the revenue requirement using a number of different scenarios for the station end of life. These alternative scenarios were as follows:

- Scenario 1A assumed that Darlington would be refurbished as planned and would operate until 2051, and that both Pickering A and Pickering B would continue to operate until 2020 and 2019, respectively, in accordance with current plans for Pickering B Continued Operations.

- Scenario 2 assumed that the DRP would not proceed and Darlington would therefore close in 2019. Both Pickering A and Pickering B would also close in 2014, assuming the Pickering B Continued Operations project does not proceed, because it would not be practical to operate Pickering A without Pickering B.

- Scenario 3 assumed no change in the status of Pickering A and B from that assumed in the application, but that the DRP would not proceed and that Darlington would therefore close in 2019.

- Scenario 4A assumed that the DRP would not proceed and Darlington would therefore close in 2019. This scenario also assumed that the Pickering B Continued Operations project goes ahead and therefore Pickering A and Pickering B would continue to operate until 2020 and 2019, respectively.

The analysis assumed that all other programs and expenditures were as proposed in the application (including CWIP for the DRP). The revenue requirement impact summarized in the following table is relative to the revenue requirement impact presented in the application (a reduction of $197.1 million).

Table 25: Summary of Test Period Revenue Requirement Impacts For Station End of Life Scenarios ($ million)

Description	Scenario 1A	Scenario 2	Scenario 3	Scenario 4A
PRESCRIBED FACILITIES				
Return on Rate Base:				
Accretion Rate on Lesser of ARC and UNL	3.2	(88.3)	(73.2)	(76.6)
Changes to Nuclear Station Service Life Impacts	4.0	(34.5)	(7.3)	(3.4)
Total Return on Rate Base Impact	7.2	(122.8)	(80.6)	(80.0)
Depreciation Expense:				
Asset Retirement Costs	28.2	190.9	181.1	139.4
Changes to Nuclear Station Service Life Impacts	(26.5)	227.8	48.5	22.4
Total Depreciation Expense Impact	1.7	418.7	229.6	161.8
Other Expenses:				
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(8.2)	0.0
Income Taxes:				
Accretion Rate on Lesser of ARC and UNL	1.1	(30.6)	(25.3)	(26.5)
Changes to Nuclear Station Service Life Impacts	0.6	(5.6)	(1.2)	(0.5)
Depreciation Expense on Asset Retirement Costs	9.8	66.2	62.8	48.4
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(2.8)	0.0
Depreciation Expense - Changes to Station Lives	(9.2)	79.0	16.8	7.8
Total Income Tax Impact	2.4	109.1	50.2	29.0
Total Revenue Requirement Impact - Prescribed	**11.3**	**405.1**	**191.0**	**110.8**
BRUCE FACILITIES				
Rate Base	0.0	0.0	0.0	0.0
Depreciation Expense Impact: Asset Retirement Costs	(1.7)	96.4	40.2	82.6
Other Expenses:				
Accretion	(2.8)	56.0	18.3	48.7
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(4.2)	0.0
Total Other Expenses Impact	(2.8)	56.0	14.1	48.7
Income Taxes:				
Impact on Bruce Facilities' Income Tax Calculation	1.2	(38.8)	(13.9)	(33.4)
Impact on Prescribed Facilities' Income Tax Calculation	(1.2)	39.4	14.0	33.9
Total Income Tax Impact	0.0	0.6	0.1	0.5
Total Revenue Requirement Impact - Bruce	**(4.6)**	**153.0**	**54.4**	**131.7**
Total Revenue Requirement Impact	**6.7**	**558.1**	**245.4**	**242.5**

Source: J10.11 (Attachment 1 - Table 1 and Attachment 3 - Table 1) and J10.11 Addendum 2 (Attachment 1A - Table 1 and Attachment 4A - Table 1)

Board staff noted that the adoption of any of the scenarios 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.

Energy Probe submitted that it does not expect Pickering A to operate until 2021, and recommended a more proximate and more likely end of service life, but was not specific.

GEC argued that the DRP has not reached a stage where it is a firm decision that should trigger the accounting changes. At a minimum, GEC submitted that the revenue requirement should be adjusted upward to reflect scenario 4A. However, GEC did not accept that Pickering B Continued Operations project makes economic sense, and argued that scenario 2 should be applied for regulatory purposes at this time.

SEC argued that scenario 3 should be adopted, with impacts adjusted for income tax.

Board Findings

For the reasons set out Chapter 5 on DRP, the Board accepts 2051 as the Darlington station end of life for regulatory purposes.

Given the current uncertainty as to the success of the Pickering B Continued Operations project, the Board has some concerns about the assumption by OPG for accounting purposes that it can continue to operate Pickering A without Pickering B. However, changing the assumptions to align the end of life dates for these two stations has a relatively small revenue requirement impact which does not warrant the difficulties inherent in having separate accounting and regulatory accounts. There will be more information on the expected end of life for Pickering A and Pickering B in the next proceeding and a new end of life may well be adopted then.

9 CAPITAL STRUCTURE AND COST OF CAPITAL

This is the second cost of service application to set payment amounts for OPG's prescribed assets. Cost of capital was extensively reviewed in the previous proceeding. OPG's circumstances are different, in a number of respects, from those of other entities that the Board rate regulates. These are reflected in the different treatment that the Board approved for OPG in that proceeding.

Since the previous decision, the Board has conducted a consultation that reviewed cost of capital policies for all of the sectors rate-regulated by the Board, including OPG. The outcome of that process was the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 (the "Cost of Capital Report"). OPG and many of the stakeholders participated in that consultation.

OPG has applied for payment amounts based on a deemed capital structure of 53% debt and 47% equity. This was the structure approved in the previous proceeding.

OPG proposed that the ROE for 2011 be set on the basis of the Board's policy (although it used 9.85% as a placeholder) and that the level for 2012 be set using the Board's policy, but that it be determined now based on Global Insight data because Consensus Forecasts only go out 12 months.

For long-term debt, OPG proposed to use the weighted average cost of actual and forecasted debt for actual debt capitalization, and the Board's deemed long-term debt rate for any incremental, unfunded long-term debt capitalization. For short-term debt, OPG used a methodology to forecast the costs of its two main sources of short-term financing, namely its commercial paper program and its accounts receivable securitization program. OPG's proposed cost of capital followed that approved in the previous payments case, EB-2007-0905.

The proposed test period capitalization and cost of capital are summarized in the following tables for each of the years in the test period.

Table 26: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2011

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	3.0%	2.64%	7.6
Existing/Planned Long-Term Debt	2,283.1	36.1%	5.53%	126.2
Other Long-Term Debt Provision	877.7	13.9%	5.87%	51.5
Total Debt	3,350.3	53.0%	5.53%	185.3
Common Equity	2,971.1	47.0%	9.85%	292.7
Rate Base Financed by Capital Structure	6,321.4	80.6%	7.56%	477.9
Adjustment for Lesser of UNL or ARC	1,523.3	19.4%	5.58%	85.0
Rate Base	7,844.7	100%	7.18%	562.9

Source: Exh. C1-1-1, Table 2

Table 27: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2012

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	2.9%	4.13%	10.4
Existing/Planned Long-Term Debt	2,502.8	38.8%	5.50%	137.6
Other Long-Term Debt Provision	725.2	11.2%	5.87%	42.6
Total Debt	3,417.5	53.0%	5.58%	190.6
Common Equity	3,030.6	47.0%	9.85%	298.5
Rate Base Financed by Capital Structure	6,448.1	81.2%	7.59%	489.1
Adjustment for Lesser of UNL or ARC	1,490.1	18.8%	5.58%	83.1
Rate Base	7,938.2	100%	7.21%	572.2

Source: Exh. C1-1-1, Table 1

The following issues were addressed in the proceeding:

- Technology-specific capital structures;
- Return on equity;
- Cost of short-term debt; and
- Cost of long-term debt.

Each issue is addressed in turn.

9.1 Technology-Specific Capital Structures

As noted above, OPG has used a deemed capital structure of 53% debt and 47% equity in its application. The deemed capital structure is applied to the rate base net of the Adjustment for the Lesser of Unfunded Nuclear Liabilities (“UNL”) or Asset Retirement

Costs ("ARC"), which is applicable only to the nuclear business. OPG's proposal is consistent with the Board's decision in the previous proceeding.

In the previous proceeding, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the regulated hydroelectric business and the nuclear business was an approach worthy of further investigation at the next proceeding. This is the only issue related to capital structure examined during the proceeding.

In response to the Board's direction in the prior decision, OPG retained Ms. Kathleen McShane of Foster Associates Inc. to determine whether there was a basis on which to establish separate capital structures. Ms. McShane analysed five different quantitative methodologies and one non-quantitative method in her report. Ms McShane also appeared as a witness in the hearing. Ms. McShane concluded that none of the methodologies provided sufficiently robust information to serve as a basis for separate costs of capital and capital structure. Accordingly, OPG concluded that it was appropriate to continue to use a single capital structure for its prescribed facilities.

Pollution Probe filed a report prepared by Drs. Lawrence Kryzanowski and Gordon Roberts. They also appeared as witnesses. Their analysis is based on a heuristic methodology comparing the relative risk of electricity transmission and distribution-only utilities and an integrated (i.e. generation and transmission/distribution) utility versus solely hydroelectric and nuclear generation businesses. They concluded that the capital structure for the hydroelectric business should consist of 43% equity and the capital structure for the nuclear business should consist of 53% equity, subject to OPG's prescribed facilities retaining an equity thickness of 47% in aggregate, as determined in the previous proceeding.

GEC's witness, Mr. Paul Chernick, did not undertake an updated analysis specifically on the issue of technology-specific capital structures, but he did express the opinion that there was a difference in the business risks of hydroelectric and nuclear generation businesses. He testified that the Board could and should make a judgmental determination of the difference.

All consultants agreed that, as the ROE is to remain constant under the Board's Cost of Capital guidelines, the only way to reflect differences in business risk is by adjusting the equity thickness of one division relative to the other.

Pollution Probe maintained that there is no dispute that the nuclear division has a higher business risk than the hydroelectric division. Pollution Probe noted that the capital structure recommended by Drs. Kryzanowski and Roberts was consistent with credit metrics needed to obtain, on a “stand alone” basis, reasonable bond ratings in the “A” credit range. Pollution Probe commented that the methodologies used by Ms. McShane in her analysis are usually used to determine the rate of return, and not the capital structure.

Energy Probe submitted that the Board should deem a higher equity ratio for the nuclear business than the hydroelectric business, setting the nuclear business equity ratio at 50% and the regulated hydroelectric business equity ratio at 40%.

GEC submitted that setting a higher cost of capital for the nuclear business would be more accurate than applying the current combined value to both businesses. GEC submitted that OPG should develop project specific discount rates for large projects to capture business risk more fully in the analysis.

AMPCO, CME, CCC, PWU, SEC and VECC supported retaining a single capital structure for the regulated business. Among the reasons cited were the unnecessary complexity of maintaining two structures and the fact that OPG borrows as a company not by business unit. CCC also commented that the analysis conducted by Drs. Kryzanowski and Roberts was largely a qualitative approach.

Board staff argued that if the Board was inclined to approve technology-specific capital structures, then the Board should also apply the cost of debt on a technology-specific basis. Board staff noted that the nuclear liabilities are treated as a form of debt financing within the capital structure but are only incorporated, appropriately, into the rate base for OPG’s regulated nuclear assets.

OPG argued that technology-specific capital structures add unnecessary complications to future applications. OPG noted that consumers do not buy power from particular producers, let alone based on generation type, and that the difference in equity ratios and resulting returns is small. OPG also argued that there is no compelling reason to accept the recommendations of Drs. Kryzanowski and Roberts. In OPG’s view, the evidence did not extend the analysis beyond that provided in the previous proceeding and therefore the conclusion of the previous proceeding should be maintained.

If the Board is inclined to approve separate capital structures, OPG submitted that the only reasonable ratios would be 45% for the regulated hydroelectric business and 50% for nuclear. OPG also argued that Board staff is incorrect in concluding that cost of debt is specific to projects, noting that the cost of debt for the projects identified in the staff submission reflect OPG's corporate borrowing costs.

Board Findings

OPG has applied the same capital structure as was approved on a combined basis for its regulated hydroelectric and nuclear generation assets in the previous payments case. The Board finds that there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.

The Board accepts that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business, and this is not contested by parties in this hearing. However, the Board finds that the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures. In short, the Board finds an inadequate body of evidence to support a change from the conclusions reached by the Board in the previous proceeding.

The evidence of Drs. Kryzanowski and Roberts is a heuristic approach and is qualitative as much as quantitative in nature. Their evidence also largely employed the same techniques as contained in their evidence in the previous case. The difficulty for the Board is the dependence on qualitative assumptions and analysis. Their qualitative assessments of various forms of risk give rise to quantitative scorings that they then have translated into different capital structures corresponding to a cost of capital related to the risks of each business division and constrained by two conditions:

1) the weighted aggregate cost of capital for the two divisions should correspond with the 47% equity thickness set by the Board on an aggregate basis; and
2) the cost of capital and hence the deemed capital structure for the hydroelectric division should be commensurate with a business risk no less risky than that for electricity distributors and transmitters, for which the Board has deemed a 40% equity thickness.

As was discussed during oral cross-examination, these conditions restrict the allowable technology-specific capital structures to a very narrow band. The Board is concerned that different qualitative scorings might result in some different results from their analysis, even while adhering to the relative riskiness (in terms of ranking) of transmission and distribution utilities versus generation technologies. In other words, as was found in the previous case, the Board considers that the heuristic approach of Drs. Kryzanowski and Roberts is not robust enough to set technology-specific costs of capital and capital structures.

With respect to Ms. McShane's evidence, the Board acknowledges its more quantitative approach, but also acknowledges some of the concerns raised by parties. For the most part, the analytical approaches used by Ms. McShane are based on the CAPM model, and thus share the strengths and limitations. The CAPM is one of several techniques routinely used by this Board and other regulators in setting the Cost of Capital. However, as was acknowledged by OPG,[44] the CAPM is not used to set the capital structure, which must be derived indirectly. However, the Board considers that the paucity of comparator firms to be more telling in Ms. McShane's analysis not being able to derive a robust estimate of technology-specific capital structures.

There may thus be a lack of major hydroelectric and nuclear generators comparable to OPG's divisions and for which market data is available to apply the methods that Ms. McShane has used. It is not to say that there is not a real difference, but that the approaches put on the record in this proceeding, as in the previous case, are not sufficient to allow for robust estimates with sufficient precision to be derived, at least at this time.

The Board is also concerned that over time a further issue will arise in relation to the interaction between the individual equity ratios and the combined equity ratio. As the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged or whether the technology specific ratios are to remain unchanged. If the overall level of 47% is to remain unchanged, then this could result in ongoing variability in the technology specific levels, which may not be desirable. Likewise, if the technology specific ratios are to remain unchanged, it might result in changes to the overall ratio that are not warranted. The Board concludes that introducing this level of variability and complexity would not be appropriate.

[44] Exh. L-10-23 and Exh. L-6-7

The Board also accepts that implementing separate capital structures may not lead to any significant ratepayer benefits in the long term.

The primary argument put forward by those who support a separate capital structure is related to the assessment of large capital projects. The Board concludes that this difference in risk can and should be adequately accommodated in the direct valuation of the projects. OPG maintained that it already does so; other parties dispute this. This issue can be pursued further by the parties in subsequent proceedings.

Another argument advanced in favour of separate capital structures is greater transparency for consumers. The Board has some sympathy with this view, but has nonetheless concluded that the benefits from this greater transparency are not sufficient to warrant the complications involved with this approach based on the evidence advanced in this or the previous payments case.

9.2 Return on Equity

Two issues were raised in respect of the return on equity: whether the Board should adjust the ROE below the level established through the operation of the Board's policy, and how the ROE should be set for 2012.

9.2.1 Should the ROE be reduced?

OPG proposed that the ROE be determined according to the formula in the Cost of Capital Report, using data from *Consensus Forecasts*, the Bank of Canada and Bloomberg LLP three months in advance of the March 1, 2011 effective date for rates.

CME maintained that unregulated industries would forego full equity return on investment if external circumstances called for price constraint. CME argued that the Board is not required to award ROE at a specific level as this is not an objective or requirement in the Act, and could award a lower rate than applied for by OPG in order to protect consumers from rising electricity prices. CME pointed out that it would be inconsistent for the ROE to be fixed at a specific rate, when the Board, in some cases, can award a higher ROE, as, for example, contemplated by the *Report of the Board on The Regulatory Treatment of Infrastructure Investment in Connection with the Rate Regulated Activities of Distributors and Transmitters in Ontario*. Also, CME suggested that, if the ROE is considered to be an absolute number, any over-earnings in a rate year would have to be returned to ratepayers in a subsequent year.

OPG argued that it is a legal requirement to permit a utility the opportunity to earn a fair return on its invested capital, and that the Cost of Capital Report applies to all utilities regulated by the Board. As noted elsewhere in this Decision, OPG also argued that it has no obligation to have regard for costs over which it has no control.

CME also argued that the Board has always looked to sources and actual costs of funds when considering cost of capital issues, and should therefore take into account that OPG's capital structure is financed by interest free government loans or grants, taxes or money the government borrows in the debt markets. CME's position was that the approved ROE only needs to exceed the government's cost of debt.

OPG argued that there is no basis to use its shareholder's cost of capital as a guide to setting ROE. OPG pointed out that if this principle were applied then it would have to be applied symmetrically and there is no precedent for this approach. Further, OPG argued that it is inconsistent with the "stand-alone" principle which the Board accepted in the previous proceeding. OPG also submitted that CME's proposition violated a basic principle of finance – that the cost of capital should reflect the riskiness of the entity or the project in which the funds are invested, not the source of the funds.

Board Findings

The Board accepts OPG's proposal to use the ROE determined on the basis of the Board's Cost of Capital Report. In the Cost of Capital Report, the Board determined that the Fair Return Standard ("FRS") is the legal basis upon which the cost of capital is determined, stating:

> The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[footnote omitted] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that

> applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[45]

In the Cost of Capital Report, the Board also stated:

> The final "product" of this process, of course, is a Board policy. This was not a hearing process, and it does not - indeed cannot - set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy).[46]

While the Board agrees that there is flexibility to apply a different ROE in appropriate circumstances, there was no evidence of a compelling reason to do so in this case. As discussed in the Cost of Capital Report regarding the legal requirement for the FRS, the Board does not agree with CME's proposal that OPG should be afforded a lower ROE to mitigate impacts on ratepayers. Rate mitigation, if warranted, is not applied specifically to the Cost of Capital; doing so would violate the FRS.

The Cost of Capital Report contemplates that a departure from the policy will only be considered where there is specific evidence in the hearing that it would be inappropriate to apply the policy in the specific circumstances of the utility. The Board finds that there was no such credible evidence in this case.

The Board also agrees with OPG that the source of its financing is not relevant for these purposes and will not adjust the ROE to reflect its shareholder's cost of debt. This issue was also raised in the previous payments decision and similar arguments were raised and addressed at that time. The Board finds that there has been no change in the evidence or circumstances which would warrant a change in approach.

9.2.2 How should the ROE for 2011 and 2012 be set?

OPG used an ROE of 9.85% for purposes of its application, but proposed that the ROE for 2011 be set using data for the month three months prior to the effective date of the

[45] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009, p. 13.
[46] *Ibid*, p. 18.

new payment amounts, as contemplated in the Cost of Capital Report. OPG proposed that the ROE for 2012 be set at the same time as the 2011 ROE but using data from Global Insight instead of the *Consensus Forecasts* used by the Board because the *Consensus Forecasts* data is only projected for 12 months.

Board staff argued that OPG's cost of capital parameters for 2011 should be set at the time this Decision is issued, but that the cost of capital parameters for 2012 should be updated prior to 2012. In support of this position, Board staff referred to recent Toronto Hydro-Electric Systems Limited ("THESL")[47] and Hydro One[48] cases, where updates of cost of capital parameters were implemented in the second year of multi-year applications.

SEC supported fixing the ROE now for the 24-month test period, citing simplicity and price stability, but expressed some reservations about forecasting markets two years out using the Global Insight forecast. SEC expressed concern about the adoption of a new data source without further review and concluded that ROE for 2011 and 2012 should be set at the same level, an approach that is consistent with that used under IRM. In the event this approach was not adopted by the Board, SEC supported Board staff's position. CME supported SEC's position.

OPG argued that the THESL and Hydro One cases should not be used as precedents because these utilities had already proposed to adjust their rates for the second year. OPG also took the position that SEC's comparison with IRM is inappropriate because OPG has no price escalation mechanism for its rates. With respect to SEC's concern about the Global Insight forecast, OPG noted that the Board had not expressed any concerns with the Global Insight forecast in the previous proceeding.

In the event that the Board directs the use of *Consensus Forecasts* data, OPG requested that a variance account be established to record the impacts of any differences arising from ROE approved in rates for 2012 and the 2012 ROE determined using September 2011 *Consensus Forecasts* data. OPG observed that this would be more efficient than updating the forecast and payment amounts for 2012, and would eliminate the need for the IESO to institute another change in the settlement system at the start of 2012.

[47] Decision with Reasons, EB-2009-0069, April 16, 2010.
[48] Decision with Reasons, EB-2009-0096, April 9, 2010.

Board Findings

The Board finds that the ROE for 2011 will be set using the data available for the three months prior to the effective date of the order, in accordance with the Board's Cost of Capital Report. The Board has calculated an ROE of 9.43% based on Bloomberg LLP, *Consensus Forecasts*, and Bank of Canada data for November 2010, which is three months in advance of March 1, 2011, and using the ROE methodology in Appendix B of the Cost of Capital Report. The detailed calculations to derive this ROE are contained in Appendix H of this Decision.

In the prior proceeding, the ROE was fixed at 8.57% for the entire test period spanning nearly two years. In part, this was a matter of timing – the decision in the previous payments case was issued on November 3, 2008, more than one third of the way through the test period. By that time there was knowledge of actual market conditions and returns and more current information for the remainder of the test period which justified approving one ROE for the entire test period.

The current application differs in that it has been filed and considered in advance of the proposed test period. OPG has proposed different treatment in setting different ROEs for each of the 2011 and 2012 test years. The Board considers it appropriate to set separate ROEs for each year of the test period. The issue is what data should be used for establishing the 2012 ROE.

The Board could adopt the same approach used in the THESL and Hydro One decisions which involves updating the ROE for 2012 using the data from *Consensus Forecasts,* Bank of Canada and Bloomberg LLP for the month 3 months prior to January 1, 2012 (i.e. September 2011) and the methodology in the Cost of Capital Report. The approach has the benefit of retaining all aspects of the ROE methodology and policy adopted by the Board, rather than adopting a new forecast method. However, it introduces procedural complications and it does necessitate the setting of new payment amounts for 2012. The Board finds that there is significant value, in terms of overall rate stability, in establishing one set of payment amounts in relation to the combined revenue requirement of the test period. In addition, if there were an update for the ROE for 2012, it would result in payment amount levels for 2012 which were derived from the 2012-specific ROE figure, but the blended test period revenue requirement impacts for all other components. The Board finds that a mechanistic update for one component of the revenue requirement, when the payment amounts in all other respects are the result of a blended revenue requirement covering the entire test period, is not appropriate in the circumstances.

The Board concludes that it is reasonable to use the Global Insight forecast for purposes of setting the ROE for 2012. The Board finds this approach is consistent with the Board's overarching policy and represents the best balance between rate stability, procedural efficiency and accurate forecasting. OPG has indicated in its Reply Argument that the ROE for 2012 is 9.55%, based on the Global Insight forecast and the Board's methodology. OPG shall file the relevant documentation as part of its draft payment amounts order, consistent with the methodology adopted by the Board in its Cost of Capital Report, supporting the derivation of the ROE for 2012.

9.3 Cost of Short-Term Debt

OPG's short-term debt is comprised of a commercial paper program and an accounts payable securitization program. OPG's estimates of the short-term debt rates for each of 2011 and 2012 are derived from Global Insight data from December 2009. OPG's short-term debt approach is consistent with that approved in the previous proceeding.

Board staff submitted that while OPG has its own methodology for forecasting short-term debt rates, it should update the rates to reflect more current data, namely data for the month three months prior to the effective date of the new payment amounts, and again prior to January 1, 2012 for the 2012 test year. In staff's view, this approach would be consistent with the Cost of Capital Report and with ensuring that all cost of capital parameters are based concurrently on the most recent data available and practical for setting rates for the test period. Board staff further argued that the updated rates should be supported with documentation respecting the calculations and source data.

SEC submitted that the short-term debt rates for both 2011 and 2012 should be updated using December 2010 forecasts. CME submitted that the Board should be consistent in how it determines the costs of short-term and long-term debt for government owned utilities.

OPG responded that Board staff had ignored the fact that the Board's Cost of Capital Report approved OPG to use the same approach for short-term debt that it used in the previous case. OPG also argued that Board staff had ignored the fact that the method approved in the previous case for setting short-term debt for OPG differs from the method used for electricity distributors. OPG prepared an Impact Statement prior to the oral hearing identifying items that exceed the $10 million materiality threshold and debt costs were not identified in the impact statement. OPG submitted that the short-term debt rate in the application is the same rate used for the business plan that underpins the application, and that it would be unfair for the Board to require it to selectively update the short-term debt costs for 2011.

Board Findings

The Board agrees with OPG that its approach to short-term debt rates is consistent with the previous decision, that it was accepted in the Cost of Capital Report, and that its forecast for the two test years is reasonable. The Board will not require OPG to update the short-term debt rates for either 2011 or 2012.

9.4 Cost of Long-Term Debt

OPG documented its actual and forecasted long-term debt for 2011 and 2012. OPG proposed that any unfunded portion of its long-term debt (the difference between the deemed long-term debt capitalization and actual or embedded debt) would attract the Board's deemed long-term debt rate based on data three months in advance of the effective date for the new prescribed payments. No parties opposed OPG's evidence with respect to its actual and forecasted long-term debt, but most parties opposed OPG's proposal for the cost of unfunded long-term debt.

Board staff argued that it is inappropriate for OPG to use the Board's deemed long-term debt rate as the cost for the unfunded portion of long-term debt. Board staff submitted that OPG's interpretation of the Board's Cost of Capital Report was inconsistent with the Board's policy and practice and that OPG's forecasted weighted average cost of existing and forecasted long-term debt should apply to the unfunded portion of long-term debt as well as to actual or embedded long-term debt.

SEC and VECC agreed with the Board staff submission, and argued that the Board should not adopt OPG's proposal because the deemed long-term debt rate is intended to be available only where there is no evidence of a utility's cost of long term debt.

OPG observed that Board staff relied on cases decided prior to the issuance of the Board's Cost of Capital Report, but noted that staff did not refer to the previous OPG case where the Board decided that it was appropriate to use the "hedged cost of planned debt" to calculate the cost of OPG's notional long-term debt. Further, OPG observed that as new debt is issued, it will be issued at future debt rates. OPG submitted that it has an active long-term borrowing program and it is not necessary to rely on the cost of historical debt as a proxy for future debt.

Board Findings

The Board agrees with Board staff's submission that the Board's deemed long-term debt rate is only intended to apply where a utility has no actual long term debt (or where the debt is held by an affiliate). This is not the case for OPG, and therefore OPG's weighted average cost of existing and forecasted long-term debt will apply to the unfunded portion of long-term debt as well as to actual or forecasted long-term debt in each test year.

OPG has suggested that this approach is not appropriate because the weighted average cost does not represent an appropriate proxy for future debt. The notional long-term debt, however, is not intended as a proxy for future debt. Forecast future debt is already incorporated into the calculations, and there was little evidence to suggest that notional debt would be replaced with actual debt during the test period. The notional debt remains a balancing item and therefore the Board concludes that the appropriate cost rate is determined using the weighted average cost of debt.

10 DEFERRAL AND VARIANCE ACCOUNTS

10.1 Introduction

OPG has three deferral and variance accounts for its hydroelectric business and nine accounts for its nuclear business. There are three additional accounts common to both businesses. Certain of these accounts were authorized under O. Reg. 53/05. All of these existing accounts were established pursuant to decisions in the first payments proceeding (EB-2007-0905), the motion proceeding (EB-2009-0038) or the accounting order proceeding (EB-2009-0174). OPG's evidence is that entries to these accounts during 2008, 2009 and 2010 have been made in accordance with the methodologies established in the relevant decisions. Interest on the accounts has been applied in accordance with the rates prescribed by the Board from time to time.

OPG proposed to clear the actual audited December 31, 2010 balances through payment amount riders. In its reply submission, OPG agreed to file audited 2010 deferral and variance account balances at the earliest possible time for possible inclusion in this Decision. No party objected to this approach. The audited balances were filed on February 7, 2011 and are presented in the table below.

Table 28: Summary of Deferral & Variance Accounts Balances from 2007 to 2009 and 2010 Audited Balances Proposed for Recovery ($million)

Account	Year End Balance 2007 (1)	Year End Balance 2008 (1)	Year End Balance 2009 (1)	Year End Balance 2010 (2)
Regulated Hydroelectric:				
Hydroelectric Water Conditions Variance	$6.3	$(21.6)	$(55.3)	$(70)
Ancillary Services Net Revenue Variance – Hydroelectric	7.2	(2.4)	(16.0)	(9)
Income & Other Taxes Variance	0.0	(0.2)	(0.3)	(8)
Tax Loss Variance	0.0	20.2	47.1	78
Interim Period Shortfall (Rider D)	0.0	(0.3)	(2.2)	(2)
Over/Under Recovery Variance – (2010)	0.0	0.0	0.0	(8)
Total	**13.5**	**(4.2)**	**(26.6)**	**(19)**
Nuclear:				
Pickering A Return To Service Deferral	183.8	129.5	81.8	33
Nuclear Liability Deferral	130.5	132.3	86.2	39
Nuclear Development Variance	11.7	(21.7)	(55.6)	(111)
Transmission Outages and Restrictions Variance	1.8	1.4	0.7	0
Ancillary Services Net Revenue Variance – Nuclear	(1.8)	(1.9)	(0.6)	0
Capacity Refurbishment Variance	0.0	(5.7)	(0.3)	(8)
Nuclear Fuel Cost Variance	0.0	(1.4)	(15.7)	6
Bruce Lease Net Revenue Variance	0.0	256.6	324.5	250
Income and Other Tax Variance	0.0	(7.8)	(12.1)	(32)
Tax Loss Variance	0.0	105.9	247.2	414
Interim Period Shortfall (Rider B)	0.0	0.3	6.6	7
Over/Under Recovery Variance – Nuclear (Rider A&C)	0.0	0.6	10.7	21
Total	**326**	**588.1**	**673.4**	**619**
Grand Total	**$339.5**	**$583.9**	**$646.8**	**$600**

(1) Source: Exh. H1-1-1, Table 1 (updated October 8, 2010)
(2) Source: Audited account balances (per Schedule of Regulatory Balances as at December 31, 2010 and Independent Auditors' Report), as filed on February 7, 2011

OPG proposed to clear the balances of all accounts (except the Tax Loss Variance Account) with payment riders effective from March 1, 2011 to December 31, 2012. OPG proposed to amortize the balance in the Tax Loss Variance Account over a 46 month period from March 1, 2011 to December 31, 2014. Based on forecast account balances, filed on October 8, 2010, of $17.4 million credit for hydroelectric and $690.1 million debit for nuclear, the forecast test period riders would be a credit of $1.66/MWh for hydroelectric and a charge of $5.06/MWh for nuclear. These riders will change to reflect the audited 2010 balances as filed on February 7, 2011. The 2010 year end balances summarized in Table 28 above, are proposed for recovery in the test period, except the tax loss variance account balances, which are proposed for recovery over a 46 month period.

OPG requested the continuation of the following accounts:

- Ancillary Service Net Revenue Variance Account – Hydroelectric and Nuclear
- Income and Other Taxes Variance Account
- Tax Loss Variance Account
- Hydroelectric Water Conditions Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Capacity Refurbishment Variance Account
- Nuclear Fuel Cost Variance Account
- Bruce Lease Net Revenues Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

OPG requested that the following accounts continue only for entries for amortization and interest and that the accounts be closed once the balances are recovered:

- Interim Period Shortfall (Rider D) Variance Account
- Pickering A Return to Service Deferral Account
- Transmission Outages and Restrictions Variance Account
- Interim Period Shortfall (Rider B) Variance Account

10.2 Existing Hydroelectric Accounts

No submissions were filed on the hydroelectric specific accounts.

Board Findings

The audited December 31, 2010 balances in the hydroelectric accounts are approved for disposition as proposed by OPG. The Board also approves the continuation of the hydroelectric accounts as proposed by OPG.

10.3 Existing Common and Nuclear Accounts

Intervenors made submissions on the following accounts: Tax Loss Variance Account (which is common to hydroelectric and nuclear); Nuclear Liability Deferral Account;

Capacity Refurbishment Variance Account; Nuclear Fuel Cost Variance Account; and the Bruce Lease Net Revenues Variance Account.

10.3.1 Tax Loss Variance Account

The Tax Loss Variance Account was established by the Board in the motion proceeding EB-2009-0038. That proceeding was held to review the Board's previous payments decision, and in particular the Board's decision in the area of tax losses for the period that preceded regulation by the Board and rate increase mitigation. The motion decision stated "the clearance of this account will be reviewed in OPG's next payment application hearing when a future panel of the Board reviews the tax analysis ordered in the Payments Decision [EB-2007-0905]." In the current proceeding, OPG seeks recovery of the December 31, 2010 balance in the account over a 46 month period. The audited balance is $492 million: $78 million is allocated to the hydroelectric business and $414 million is allocated to the nuclear business.

The Tax Loss Variance Account and the history of the tax losses is a matter of considerable complexity. It is useful to review the history of this issue through the various proceedings.

In the previous payments proceeding, OPG recognized that the revenue requirement increase it was requesting was significant and would result in a 19% increase in payment amounts. OPG identified that the regulatory taxable income calculation for the years 2005-2007, the period during which the Province established the payment amounts and before the period in which the Board set the amounts, resulted in tax losses for those years. OPG calculated the regulatory tax losses at the end of 2007 to be $990.2 million in total. OPG proposed to accelerate the application of the available tax losses to reduce the test period revenue requirement in order to mitigate the increase in the payment amounts to 14.8%. Specifically, OPG proposed to exclude the 2008-2009 test period tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million.

In the payments decision, the Board stated that it was not convinced that there were any regulatory tax losses to be carried forward to 2008 and later years. The Board directed OPG to file better information on its forecast of test period income tax provision and a re-analysis of the prior period tax returns in its next application. The Board also required OPG to provide mitigation in an amount that was proportional to the originally proposed mitigation amount (i.e. 22% of the revenue deficiency). The resulting mitigation was $168.7 million.

OPG filed a motion for a review and variance of the original decision related to these matters. The Board granted the motion and made the following decision:

> The Board varies the Payments Decision [EB-2007-0905] in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses.[49]

In the current proceeding, OPG's evidence is that the Board's EB-2007-0905 decision reduced OPG's revenue requirement by $342 million, consisting of $168.7 million for the mitigation amount and $172.5 million for the elimination of the tax provision for 2008 and 2009. This amount was also identified during the motion proceeding. OPG described the determination of this amount as follows:

- The amount of mitigation included in the EB-2007-0905 decision (excluding tax) was $168.7 million.
- The benchmark tax expense for the previous test period was $66 million.
- The provision for taxes and gross up is $106.5 million.
- The total is $341.2 million

In accordance with the Board's decision in EB-2007-0905, OPG recalculated its regulatory tax losses for the period April 1, 2005 to March 31, 2008 to be $188.5 million. OPG described the adjustments it made to the original estimate of $990.2 million to arrive at $188.5 million as follows:

- The Board's decision on the Pickering A Return to Service Deferral Account ("PARTS") required OPG to provide tax benefits to coincide with the timing of the recovery of the costs. OPG determined that this would reduce the tax loss by $147 million.
- The previous decision stated that any calculation of tax loss "in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce

[49] Decision and Order, EB-2009-0038, May 11, 2009, p. 15.

lease." OPG determined that the tax loss should be reduced by $390 million as a result.

- The Board noted in the previous decision that the operating loss in 2007 was borne completely by OPG's shareholder, which reduced the tax loss by $234.2 million.
- OPG determined that a further $37 million reduction was required due to an update of information for 2007 and that a $6.5 million addition was required due to allocation of adjustments to the period prior to regulation.

OPG engaged Ernst & Young to apply specified procedures guided by section 9100 of the CICA Handbook to reconcile information in OPG's corporate tax returns to the determination of prior period tax losses for the prescribed facilities for 2005, 2006 and 2007. Ernst & Young was able to tie the numbers on the schedules back to the source documents with no exceptions.

From this amount of $188.5 million OPG deducted the $77.6 million in taxable income for the period January 1, 2008 through March 31, 2008. This left $110.9 million in remaining net cumulative losses, or a revenue requirement amount of $50.3 million.

The difference between the revenue requirement reduction ($342 million) and the remaining tax loss ($50.3 million), being $290.9 million, was booked to the account for the period April 1, 2008 through December 31, 2009. OPG forecast the amount for 2010 to be $195 million, being an annualized grossed-up amount of the $342 million revenue requirement reduction during the original 21 month test period. To these amounts OPG also applied interest at the Board prescribed levels.

SEC provided in its argument a detailed alternative estimate of the appropriate amounts to be considered in respect of this issue. SEC submitted that there should be no regulatory tax liability for the period 2008 to 2012 because of timing differences which SEC has determined are in the order of $1,660.4 million. In SEC's view, these amounts, which are tax deductions taken by OPG prior to April 1, 2008, should be available to ratepayers. SEC estimated that an amount between $450 million and $500 million would remain available for deduction in 2013 and beyond.

The principle that SEC relied on in its submission is "benefits follow costs" which SEC describes as meaning "if the ratepayers bear a cost in their rates, then any tax impacts that flow from that cost accrue to the ratepayers as well."[50] In particular, SEC is concerned with the application of this principle with respect to tax related timing differences. "Timing difference" refers to government tax policy which in SEC's words "allows taxpayers to front load their tax deductions, and thus save tax dollars, as a way of providing economic stimulus and incenting long term spending."[51] SEC asserted that the general pattern is one of tax savings in the early years and tax costs in later years and in general the regulatory system matches this by using a taxes payable approach to setting rates.

In OPG's case, however, SEC argued that the balance is disrupted because OPG became regulated part way through the tax benefit period, meaning that the shareholder will have gained from the tax benefits in the pre-regulation period and ratepayers will bear the balancing tax costs in the regulation period. In SEC's view, the appropriate approach is to re-examine the relevant periods to ensure ratepayers receive the benefits of these timing differences.

SEC reviewed the evidence and determined that OPG had $1,660.4 million of timing differences (including amounts related to Bruce) in the three years prior to April 1, 2008 which should be available to ratepayers. The largest component (over $1.2 billion) is related to nuclear waste and decommissioning costs. These amounts include impacts related to Bruce, because in SEC's view, when the Board decided that GAAP should be used to calculate the net Bruce lease revenue, the Board was "not intending to say that Bruce should be an exception to the "benefits follow costs" principle related to tax calculations."[52]

SEC further argued that the tax losses prior to April 1, 2005 should also be considered for potential availability to ratepayers and recommended that the Board direct OPG to prepare a detailed review of the losses at the next proceeding.

OPG opposed SEC's analysis on three principal grounds. First, OPG argued that SEC's analysis consists of untested evidence. In OPG's view, SEC's approach is a form of opinion/expert evidence and no authority has been provided for the positions taken in relation to the accounting and regulatory principles related to tax/accounting timing differences.

50 SEC Argument, para. 10.2.9.
51 SEC Argument, para. 10.2.16.
52 SEC Argument, para. 10.2.63.

Second, OPG argued that SEC's analysis violates Board approved regulatory principles and does not comply with accepted tax and accounting practices. In OPG's view, tax loss carry forward is a concept which is recognized in the *Income Tax Act* and OEB regulated tax calculations but timing differences carried forward have no basis in accounting. OPG further argued that SEC's generalization regarding the pattern associated with timing differences is incorrect and pointed, for example, to testimony that deductions for nuclear liabilities are only available when actual cash expenditures are made. OPG also submitted that whereas it applies the deductions against earnings before tax and carries forward any resulting loss, SEC ignores earnings before tax and does not apply the deduction in the period for which it applies.

Third, OPG maintained that SEC's analysis is based on misinterpreted facts and faulty assumptions. OPG provided an analysis of why, in its view, SEC's analysis is flawed. For example, OPG explained that its treatment of the PARTS amounts, unlike SEC's proposal, is based on the Board's direction in the first payments decision which required that the timing of PARTS recovery match the timing of providing the associated tax cost or benefit to ratepayers. OPG also pointed to the incomplete nature of SEC's analysis and the lack of identification of adjustments to earnings that were additions. OPG further argued that SEC had incorrectly applied the "benefits follow cost" principle, and OPG has appropriately excluded Bruce lease revenues and costs from its tax loss determination. OPG also argued that SEC has ignored the provisions of O. Reg. 53/05 sections 6(2)5 and 6(2)6 which require the Board to accept the revenue requirement impact of accounting and tax policy prior to the effective date of the Board's first order.

OPG further argued that there is no basis to review the period before April 1, 2005 and therefore SEC's proposal that related evidence be provided at the next proceeding should be rejected.

CME supported SEC's submissions but also presented another approach related to the mitigation amount in relation to the original proceeding. CME pointed out that OPG's evidence in the original proceeding was that a 19% increase was excessive and needed to be reduced in order to bring the increase to about 14.8% to be reasonable. CME estimated this amount to be $360 million. OPG responded that the motion decision varied the original decision in a way that links the mitigation with the regulatory tax losses. OPG argued that CME has mischaracterized the nature of OPG's original proposal as being focused on mitigation.

VECC and CME argued that no amount associated with 2010 should be recoverable. In VECC's view, "The decision establishing the test period Tax Loss Variance Account never contemplates, either explicitly or implicitly, the operation of a similar account beyond 2009."[53] VECC asserted that it is clear in the decision that the variance to be tracked was limited to the test period. VECC went on to submit that if the Board rejects this argument, then at a minimum the $195 million for 2010 should be reduced by $26.2 million to reflect the reduced tax amounts related to nuclear liabilities in 2010. VECC also submitted that had OPG proposed the tracking of $195 million in the accounting order proceeding, EB-2009-0174, intervenors may have made submissions and the Board may have considered different relief. This position was supported by CME and SEC.

OPG replied that the accounting order proceeding was about the mechanics of booking entries in accounts in 2010 and that there was no need to make a request for this matter for the tax loss variance account. Further, OPG stated that it was not necessary to seek extended terms for any of the deferral and variance accounts:

> …payment amounts are established based on a test period, but they remain in place until changed by the OEB. Similarly, unless the OEB explicitly states otherwise, variance and deferral accounts established in relation to those payment amounts also continue until changed by the OEB.[54]

OPG also rejected VECC's proposal that the 2010 balance be reduced by $26.2 million related to the tax impacts of changes in nuclear liabilities. OPG maintained that the account does not cover changes in 2010 actual amounts resulting from the Darlington Refurbishment project:

> The revenue requirement impact pertaining to income taxes should be treated the same as the revenue requirement impact associated with non-tax factors. They are simply not relevant to the determination of the test period revenue requirement.[55]

CCC supported SEC's submission, but argued that the Board should defer consideration of the tax loss variance account to a separate proceeding, and that an independent expert should report on the issue. OPG objected to this suggestion

[53] VECC Argument, para. 119.
[54] Reply Argument, p. 196.
[55] Reply Argument, p. 156.

referring to direction in the EB-2007-0905 and EB-2009-0038 decisions which stated that the matter would be addressed in this payment amounts application.

Board Findings

The Board approves recovery of the balance in the Tax Loss Variance Account in accordance with OPG's proposal to recover the balances over a 46 month period. However, the riders that will be given effect by this Decision and subsequent payment order will be effective until December 31, 2012.

CCC argued that the matter should be deferred to another proceeding. The Board does not agree. It was made clear in the motion proceeding and the prior payments decision that the issues were to be resolved in this proceeding. It would only be appropriate to defer consideration of the issue if there were insufficient evidence on the record. That is not the case here.

SEC argued that the appropriate application of the "benefits follow costs" principle, which was articulated by the Board in the original payments decision, would see the inclusion of the impact of timing differences in the calculation of the tax amounts. The result of SEC's approach would be a proposed credit for ratepayers resulting from net timing differences of $1,660.4 million. Of this $1,660.4 million, SEC identified $1,052.4 million for the prescribed facilities and $608.0 million for Bruce.

OPG has pointed to significant deficiencies in SEC's analysis, and the Board finds that OPG's criticisms have merit. For example, the Board agrees that OPG's treatment of the amounts related to the PARTS account is consistent with the Board's prior decision which required that the timing of the tax effect be aligned with the recovery of the cost. The Board also accepts OPG's evidence that the effect of timing differences is not always as SEC has posited, and in particular not in the case of asset retirement costs. The Board also concurs with OPG's position that it is clear the Board intended for Bruce revenues and costs to be excluded from the analysis. For these reasons, the Board finds SEC's calculations and estimations to be unpersuasive.

With respect to amounts in the account for 2010, the Board finds that there is no basis in the motion decision for the proposition that this account was only effective during the prior test period. The section of the decision that has been quoted by the parties is as follows:

> The Board varies the Payments Decision [EB-2007-0905] in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses.[56]

The parties opposed to any recovery for 2010 point to the phrase "the tax loss mitigation amount which underpins the rate order for the test period" as the basis for their position that the account was only established for the duration of the test period. The Board does not agree that the decision is appropriately interpreted in that way for two reasons. First, the plain reading of the phrase indicates that the words "for the test period" are meant to describe the relevant rate order. Second, the Board indicated that the account was to be cleared, and the relevant issues addressed, in the next proceeding. While parties might have expected that the next proceeding would follow directly from the prior test period, having found that the original decision was in error and that the payment amounts included amounts which would need to be adjusted at a future time, it does not follow that the Board would have intended for the account to have a fixed duration for only the test period. In essence, the account was put in place to correct an error in the original decision and as long as those original payments were in place the error continued to exist.

The Board also rejects CME's argument that the account should be adjusted to reflect a quantification of the appropriate level of mitigation. The scope of the account was clearly set out in the motion decision and there is no suggestion that any amounts in addition to the description of the appropriate variance are to be contemplated for purposes of mitigation.

VECC argued that at a minimum the Board should reduce the 2010 balance by $26.2 million to reflect the reduced tax amounts related to nuclear liabilities in 2010 (as compared to the original test period). The Board does not agree. VECC is proposing an adjustment to the original mitigation amount ($341.2 million) to reflect one component of actual results, but the motion decision defined and fixed the original mitigation amount as "the tax loss mitigation amount which underpins the rate order for the test period." This wording effectively fixes the amount at the level which underpinned the original payment order and contemplates no adjustment for actual

[56] Decision and Order, EB-2009-0038, p. 15.

results in relation to regulatory taxes paid during the period. No adjustments have been made to reflect actual regulatory taxes for the original 2008 and 2009 test period; it would likewise be inappropriate to adjust the 2010 amount.

10.3.2 Nuclear Liability Deferral Account

OPG incurs costs associated with decommissioning its nuclear facilities and managing used fuel and low and intermediate level waste. These costs are recognized as expenses over the life of the nuclear stations and are included in payment amounts because they are part of the cost of operating the nuclear stations.

The Nuclear Liability Deferral Account (Transition) was established in 2007 in accordance with section 5.1(1) of O. Reg. 53/05 to capture the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"). Section 5.1(2) of the O. Reg. 53/05 provides that simple interest be applied on the monthly opening balance at an annual rate of 6%. That account was in effect until the Board's first order.

The previous proceeding established the current Nuclear Liability Deferral Account effective April 1, 2008 pursuant to section 5.2(1) of O. Reg. 53/05. The Board directed OPG to record the return on rate base using the average accretion rate on OPG's nuclear liabilities of 5.6% for the test period.

SEC observed that the balance in the account, as noted in the previous decision, was $130.5 million and that no changes to the reference plan under ONFA have taken place. SEC stated that the opening balance of the account on April 1, 2008, as noted in the current application, was $163.9 million with an amount of $31.3 million recorded in the first quarter of 2008.

OPG replied that the difference between nuclear liability costs embedded in payment amounts approved by the province for the period up to March 31, 2008 and those costs arising from the reference plan under ONFA are captured by the Nuclear Liability Deferral Account. OPG referred to the 2008 OPG Audited Financial Statement and the first quarter 2008 Financial Statements. Both noted an increase to the nuclear liability deferral account of $37 million of which $6 million is interest.

Board Findings

The Board is satisfied with OPG's explanation for the entries in the Nuclear Liability Deferral Account (Transition) for the first quarter of 2008 in relation to section 5.1(1) of O. Reg. 53/05.

10.3.3 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was established to capture the difference between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington and (ii) OPG's actual revenues and costs in respect of Bruce based on Generally Accepted Accounting Principles. The cost impact of any changes in nuclear liabilities related to Bruce would also be recorded in this account. The balance in this account as of December 31, 2010 was $250 million.

Board staff noted that OPG proposed to recover the large balances in other accounts over an extended period to mitigate the impact on rates. In particular, OPG proposed to recover the balance in the Tax Loss Variance Account over 46 months, and in the previous proceeding the Board approved a 45 month recovery period for the Pickering A Return to Service Deferral Account (although OPG had proposed a 12 year recovery period). Accordingly, Board staff submitted that a 46 month recovery period was appropriate for the Bruce Lease Net Revenues Variance Account. CCC supported this proposal.

OPG replied that Board staff did not provide a target level for rate increases and that staff did not acknowledge the impact of deferring recovery on OPG. OPG also noted that extending the recovery period would push rate pressure into the next test period. OPG further argued that the Pickering A Return to Service account was not an appropriate example to follow because OPG's original proposal was for recovery over 12 years, with carrying costs based on the weighted average cost of capital, to match the underlying asset life. OPG rejected the view that accounts with large balances should be recovered over a longer term and argued that the extended recovery for the tax loss variance account provides sufficient rate mitigation.

SEC observed that the balance in the account is largely due to the loss on the segregated funds in 2008 and submitted that this was a one-time event that is not likely to recur. In SEC's view, the proposed recovery of almost $300 million during the test period for a one-time event is not appropriate and not in accordance with the original intent of the account. Like Board staff, SEC proposed that a 46 month period was appropriate. OPG replied that the Board's decision in the previous proceeding was clear on the need for the account and the account entries. OPG submitted that it is unnecessary to consider whether the balance is due to unusual one-time events or the original intention of the account.

Board Findings

The Board acknowledges that the balance in the account is significant and that an extended recovery period could provide additional rate mitigation. However, the Board concludes that further mitigation is not required in the context of this application. The proposed disposition period is approved.

10.3.4 Capacity Refurbishment Variance Account

The operation of this account in respect of the Pickering B Continued Operations project has already been addressed in Chapter 4.

The only other issue raised by the parties in respect of this account relates to the cost of Pickering B refurbishment studies. AMPCO submitted that the Board should disallow $4.9 million related to Pickering B refurbishment studies because in AMPCO's view it is clear that it was never worthwhile to study the refurbishment of Pickering B. OPG replied that the evaluation of Pickering B refurbishment was undertaken pursuant to a shareholder directive and that OPG's proposed spending was reviewed and approved in the previous proceeding and concluded that the Board should reject AMPCO's submission.

Board Findings

The Board will not remove the costs associated with the Pickering B refurbishment studies. These activities were prudently undertaken and the costs are therefore eligible for recovery under O. Reg. 53/05 and the account.

10.3.5 All Other Existing Common and Nuclear Accounts

The audited December 31, 2010 balances in the other common and nuclear accounts are approved for disposition as proposed by OPG. The Board also approves the continuation of the existing common and nuclear accounts as proposed by OPG.

10.4 New Accounts Proposed by OPG

10.4.1 IESO Non-energy Charges Variance Account

As a load customer, OPG pays IESO non-energy charges. OPG maintained that these charges are difficult to forecast, principally because of the Global Adjustment Mechanism. OPG noted that variances in the IESO non-energy charges have been material and have occurred in both directions in recent years. OPG also noted that effective January 1, 2011, O. Reg. 398/10 will change the method used to collect the Global Adjustment Mechanism, potentially compounding forecasting difficulties due to the uncertain impact on the behaviour of large volume consumers.

Board staff submitted that it would be reasonable for the Board to approve the account as the charges are largely pass-through and there are considerable challenges in forecasting them. If the account was approved, however, staff questioned whether OPG would have an incentive to implement energy efficiency measures and suggested that OPG should be required to demonstrate efforts to reduce consumption from the IESO grid. CCC was not opposed to OPG’s account request and supported Board staff’s suggestion that OPG be required to demonstrate efforts to reduce energy consumption prior to clearing the account. OPG responded that it was prepared to provide evidence that it is making efforts to reduce consumption which are economic and practical.

As an alternative, Board staff observed that the variance for years in which there were no vacuum building outages hovered around $10 million. Accordingly, Board staff submitted that it would not be unreasonable to deny the account on the basis that the amounts were not material. OPG responded that a variance of $10 million was material and highlighted its view that the level and volatility of the Global Adjustment Mechanism was expected to increase over time and that therefore the variance would increase substantially.

SEC agreed that IESO non-energy charges are material and can cause dramatic changes in the delivered cost of electricity. However, in SEC’s view, the fact that the electricity bill may be unpredictable is a normal business risk, and part of the risks for which a cost of capital is allowed. SEC cautioned that approval of the account could encourage other utilities to seek broader protection against normal business risks. SEC observed that, if anything, OPG has less right than other ratepayers to have this variance account as 25% of the Global Adjustment Mechanism for the 12 month period ending August 2010 was paid to OPG.

OPG disagreed that these charges are a normal business risk arguing:

> While these charges may have been part of normal business risks several years ago, and may again return to some level of predictability in the future, in more recent years and for the test period, owing to volatile components of these charges, most notably the Global Adjustment, these charges are well outside normal business risks.[57]

Board Findings

Board staff and CCC have characterized these charges as a "pass-through". However, these charges are only a pass-through if the Board accords that treatment to them. The concept of pass-through is appropriate, for example, in the case of the treatment of natural gas supply costs. Natural gas distribution utilities purchase natural gas and transportation services which are then sold to their customers without a mark-up. In these circumstances it is appropriate that the utility be kept whole, in other words that the supply costs are "passed through" to customers, through the use of a variance account. That is not the circumstance here. Electricity charges are a business expense for OPG, and while it may be difficult to forecast these charges and there are varying expectations for the rate of growth of these charges, they are certainly a business risk faced by all participants in the electricity sector in Ontario. Since this is a risk faced by all market participants, the Board concludes that it is a normal business risk. The request for the account is denied.

10.4.2 Pension and Other Post Employment Benefits Cost Variance Account

The Board has not approved the establishment of this account. Details are contained in Chapter 6.

10.5 New Accounts Proposed by Other Parties

A number of accounts were proposed by OPG or intervenors through argument. Each proposal for an account was made in the context of a specific issue in the hearing (for example, production forecast, other revenue, cost of capital, etc.). For purposes of this

[57] Reply Argument, p. 206.

Decision, the Board has addressed each proposal for an account in the context of the broader issue. The only new accounts to be established are for Surplus Baseload Generation (Hydroelectric) and the Hydroelectric Incentive Mechanism.

11 DESIGN AND DETERMINATION OF PAYMENT AMOUNTS

11.1 Design of Payment Amounts

OPG proposed no changes to the previously approved payment amounts design. Currently, the hydroelectric and nuclear payment amounts are each 100% variable amounts based on forecast production. OPG proposed that the payment amount for the regulated hydroelectric facilities be determined by dividing the hydroelectric revenue requirement by the forecast hydroelectric production. Based on OPG's filing, the payment amount would be $37.38/MWh. Similarly, OPG proposed that the payment amount for the prescribed nuclear facilities be determined by dividing the nuclear revenue requirement by the forecast nuclear production. Based on OPG's filing, the payment amount would be $55.34/MWh. No issues were raised with respect to this methodology and the Board finds that the previously approved methodology should continue. The precise levels of the payment amounts will be determined on the basis of the Board approved revenue requirements and production forecasts.

OPG proposed the use of separate payment riders for hydroelectric and nuclear for purposes of clearing the respective deferral and variance account balances. The precise levels of the payment riders will be determined on the basis of the Board approved deferral and variance account balances and production forecasts. The recovery of the deferral and variance account balances is dealt with in Chapter 10.

OPG also proposed to maintain the same Hydroelectric Incentive Mechanism. A number of parties opposed OPG's proposal. This issue is addressed below.

11.2 Hydroelectric Incentive Mechanism

In the previous proceeding, OPG proposed and the Board approved a hydroelectric incentive mechanism ("HIM"). Under the HIM, OPG receives the regulated payment amount for the actual average hourly net energy production over the month. For production above the monthly average hourly volume in a given hour, OPG receives market prices. For production below the monthly average hourly volume in a given hour, the amount payable to OPG at the regulated payment amount is reduced by the production shortfall multiplied by the market price. The purpose of the HIM is to incent OPG to move production from periods of low value to periods of higher value, based on market signals. The incremental revenues (above the regulated payment amounts) are retained by the company and not returned to ratepayers.

While there is some peaking capability at all the regulated hydroelectric facilities, the majority of peaking activity occurs at the Sir Adam Beck complex, and specifically the pump generating station (“PGS”). OPG can move substantial quantities of energy from off-peak to on-peak periods. The cost of pumping in the off-peak period is compared with the forecast value of the additional generation in the next on-peak period, and vice versa.

OPG estimated that between December 2008 and December 2009, the HIM reduced average market prices by $1.14/MWh, and in OPG’s view this demonstrates the value of moving energy from off-peak to on-peak. The forecast HIM revenue for 2009 was $12.0 million, but the actual was $23.2 million. The forecast HIM revenue for 2010 was $8.0 million, but the year-to-date actual at the end of August 2010 was $11.0 million. For the test period, OPG forecasted HIM revenues of $13.3 million for 2011 and $16.3 million for 2012. OPG expects market price spreads to decline relative to 2009.

Board staff, AMPCO, CME, CCC, Energy Probe and VECC made submissions on the HIM. In general, parties submitted that the incentive was excessive and that a sharing mechanism was appropriate. Board staff proposed a graduated sharing mechanism combined with a thorough review of the HIM forecast methodology. CCC proposed that ratepayers receive 75% of the HIM revenues, with 25% for OPG. CME took the same position.

Board staff also submitted that the sharing mechanism would reduce the relative value of the HIM for OPG in comparison to pumping water in response to SBG conditions, thereby increasing the likelihood that OPG will pump water during SBG rather than spill it.

VECC submitted that the HIM should be discontinued in its entirety because, in VECC’s view, OPG confirmed during the oral hearing that it could operate exactly as it does now in the absence of the HIM. In VECC’s view there is no basis for providing an additional financial incentive related to the operation of these regulated assets; all proceeds should flow to the ratepayers. In the alternative, VECC supported a 75%/25% sharing between ratepayers and the shareholder (or 50%/50% sharing if 90% of the forecast level is built into the forecast revenue).

OPG responded that any sharing mechanism will tend to reduce the frequency and use of the PGS resulting in less time shifting of generation because the benefits to OPG will be reduced without reducing the risks. Further, OPG stated that while parties may view a sharing mechanism as beneficial, in OPG's view it comes at a cost of reduced market benefit for consumers.

Board staff submitted that due to the large proportion of energy supplied through contract pricing, the market price is largely irrelevant in establishing electricity costs for consumers. CCC also took the view that the claimed reduction in market prices was not supported by the evidence. OPG replied that it has no control over the Global Adjustment Mechanism and bases its decisions on market price spreads and maintained that "any decrease in HOEP does not necessarily result in a one-for-one increase in Global Adjustment payments."[58] OPG further asserted "any drop in HOEP will still result in savings to consumers."[59]

Energy Probe did not support a sharing mechanism. Energy Probe argued that the HIM formula is flawed, and noted that it had identified this situation in the previous proceeding and that the evidence in this proceeding confirmed that the flaw was significant. In Energy Probe's submission, the current formula subtracts 100% of energy used to pump from the calculation of hourly volume, thus reducing the hourly volume threshold which determines the base amount in the HIM formula, but when OPG generates from the PGS it recovers some of the energy used for pumping. Energy Probe submitted that this recovered energy is 44% of the energy consumed to pump. Therefore, the adjustment to hourly volume from PGS consumption should be 56% in Energy Probe's view, not 100%. Essentially, OPG is actually consuming 56% of the energy used to pump water while storing and recovering the remaining 44% when it releases the water from the PGS. Energy Probe concluded that the Board should eliminate the circularity or "second payment" in the present HIM formula, by adding a correction to the calculation of MWavg.

AMPCO also proposed that the formula be modified by adjusting the hourly average rate (for the month) to remove the effect of PGS's turn-around energy losses.

OPG acknowledged that pumping lowers the hourly volume, but went on to submit:

[58] Reply Argument, p. 29.
[59] Reply Argument, p. 29.

> However, to artificially increase the net energy used to determine the hourly volume by ignoring the energy used for pumping creates a fictional situation where the energy threshold is set higher than what is achieved in any given month.[60]

OPG maintained that if the threshold was set artificially high, the benefits to consumers and OPG would be reduced.

Board Findings

The purpose of the HIM is to provide OPG with incentives to operate the PGS in a way which benefits consumers. OPG maintained that it was appropriate to demonstrate the success of the HIM on the basis of market price spreads. However, market prices are only one component of the price paid by consumers for electricity generation, and even though OPG may have no control over the Global Adjustment Mechanism, the ultimate value for consumers from the HIM must be assessed in light of the actual generation costs borne by consumers, not just one component of those costs.

The evidence does not support a conclusion that the current structure of the HIM is providing significant benefits for consumers. It is clear that a substantial portion of the market is now under contract and that fluctuations in the market price are largely offset by variations in the Global Adjustment Mechanism. In relation to this issue, OPG argued that this effect is not one-for-one, but in relation to the issue of a variance account for IESO non-energy charges, OPG argued that lower market prices do result in corresponding increases in the Global Adjustment Mechanism. The Board finds that the net benefits to consumers are likely substantially less than estimated by OPG on the basis of market price differentials alone.

The Board also sees an important relationship between the HIM and SBG. In this Decision, the Board has decided that OPG will be compensated for SBG. Under these circumstances, the Board concludes that while there may be consumer benefits from OPG shifting production between low market value and high market value periods, this shifting is of greatest benefit to ratepayers if in the first instance it mitigates the level of SBG – when ratepayers will otherwise pay the regulated payment amount for generation lost through spill related to SBG.

The Board will not make the adjustment proposed by Energy Probe. While the Board agrees with Energy Probe's concern regarding the circularity of the formula and the

[60] Reply Argument, p. 30.

resulting addition to the incentive payment, the Board's conclusion is that it is more appropriate to re-visit the structure of the HIM in its entirety in the next proceeding rather than attempt to modify it in incremental ways in this proceeding. Instead, the Board will adjust the rate of incentive both directly and through the operation of the SBG variance account.

The Board finds that it is appropriate to reduce the level of incentive for OPG. The incentive is paid for directly by consumers; it is not the result of incremental business from other customers. This incentive is a premium paid by ratepayers to OPG so OPG will operate in a way which is of greater benefit to ratepayers. The Board has already found that OPG has not adequately substantiated its claim of consumer benefits, and therefore, until a more robust structure is established, the Board will require that 50% of the proceeds of the HIM be returned to customers and will incorporate HIM revenues into the revenue requirement as a revenue offset.

The Board will also adjust the HIM through its review of the SBG deferral account. OPG has indicated that it will use the PGS to mitigate SBG if the price spreads warrant it. However, for production that is lost due to SBG, ratepayers will compensate OPG directly for the full volume at the regulated payment level. The Board therefore expects OPG to use the PGS to the maximum extent possible to mitigate this additional direct cost on ratepayers. When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly. The Board expects that this approach will have the effect of moderating the total level of incentive available to OPG, but concludes that it is a better structure to ensure direct benefits to ratepayers.

In recognition of the potential interaction between SBG and HIM, the Board will only incorporate a portion of the HIM revenue forecast into the revenue requirement: $5 million for 2011 and $7 million for 2012. The Board also directs OPG to establish a variance account to track all additional HIM net revenues above this forecast provision. Additional net revenues up to $5 million in 2011 and $7 million in 2012 will all be retained by OPG, and any additional net revenues beyond those levels will be shared equally between OPG and ratepayers.

The Board also directs OPG to re-address the HIM structure in its next application. Specifically, the Board expects OPG to provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market. If OPG is unable to perform this analysis through lack of information, then the company should seek to have the analysis performed by an agency with access to the necessary information. It may well be appropriate for OPG to request that the IESO examine the issue and provide suitable evidence or for OPG to work with the IESO to prepare the evidence.

12 REPORTING AND RECORD KEEPING REQUIREMENTS

OPG currently has no obligation to file financial and operating reports with the Board on a regular basis. The Board established Electricity Reporting and Record Keeping Requirements ("RRR") in 2002. Distribution utilities file financial and operating information on a quarterly and annual basis in accordance with the RRR and as a condition of their licence.

At issue in this proceeding is what reporting requirements should be established for OPG and whether a RRR should be established for the company. Board staff proposed a list of potential RRR documents during the proceeding. OPG confirmed that it could provide many of the documents.

Board staff and SEC submitted that OPG should begin filing RRR in 2011. OPG did not object to the establishment of RRR, but submitted that a separate process would be appropriate in order to establish requirements which recognize cost considerations and are minimally intrusive. In OPG's view, its RRR should be tailored to its regulatory environment and the potential IRM regime. OPG referred to the Board's approach to RRR for natural gas utilities as an example of the process to follow.

In terms of financial information, OPG confirmed that it can provide information that is publicly available in its Management's Discussion & Analysis ("MD&A") and unaudited interim (quarterly) consolidated financial statements as well as its annual MD&A and audited consolidated financial statements, and when available its annual report. These documents reflect the financial performance of OPG as a whole.

OPG objected to providing audited financial statements for the prescribed facilities on an annual basis. The decision in the previous proceeding directed OPG to file audited financial statements for the prescribed facilities, and OPG provided those financial statements for 2008 and 2009 with the current application. OPG claimed that the statements are time consuming and cost $400,000 to produce. Further, OPG maintained that any comparison with Hydro One's capability to file separate financial statements for the distribution and transmission businesses is inappropriate as OPG's financial and monitoring systems were designed before identification of the prescribed facilities. OPG has one system for all accounts and one general ledger. OPG also observed that the statements were not referred to during the current proceeding.

Board staff submitted that OPG should prepare a report for the Board detailing the costs to develop the capability to produce audited annual financial statements for the prescribed facilities.

SEC argued that OPG should be required to establish appropriate systems that would lead to the efficient preparation of audited financial statements for the prescribed facilities. SEC noted that the prescribed facilities are the biggest part of OPG's business and that OPG receives substantial benefit from being regulated and that being regulated entails providing reliable, independent information. SEC suggested that OPG should take the opportunity to revise its systems in parallel with system changes for IFRS. SEC also argued that the reason evidence is not the subject of cross-examination is because its meaning is clear, and that the audited financial statements for the prescribed facilities assisted parties in understanding OPG's business.

OPG proposed the filing of an annual regulatory return as an alternative to audited financial statements for the prescribed facilities, although OPG noted specific requirements have not been defined. OPG was not persuaded by SEC's position that lack of reference to the audited financial statements is not an indication of limited value, and noted that documents that are important to the outcome of a hearing are typically discussed. OPG argued that there was no discernable value to be gained from Board staff's suggestion to prepare a report detailing the costs to develop the capability to produce the financial statements.

Board Findings

Regular reporting of financial and operating data is an important component of the overall regulatory structure. The data allows the Board to monitor the performance of utilities in years when they are not before the Board and provides consistent data over time for purposes of various analyses. Ongoing reporting will be particularly important as OPG migrates to an IRM regime.

The Board does not believe a separate consultation is required in order to establish initial reporting requirements for OPG. There is sufficient information before the Board at this time to determine appropriate reporting requirements for 2011 and 2012. The issue of reporting requirements can also be addressed again in the next proceeding. The Board concludes that determining the reporting requirements in the context of a payment amounts proceeding will be more efficient and less costly than undertaking a separate consultation process. The Board therefore finds that the following reports shall be filed, beginning in 2011:

- 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 within 120 days for December year-end statements as long as the OSC requires these documents to be filed;
- Nuclear unit capability factors 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;
- FTE 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; and
- 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 similar to what is set out in Exhibit C1, tab 1, schedule 1, table 7 for the historical period.

The Board may consider additional or modified reporting requirements for OPG when the company brings forward its incentive regulation mechanism proposal. As part of that application, OPG should propose the suite of RRR that might be applicable for its incentive plan period.

The Board finds that it is appropriate to continue to require OPG to provide annual audited financial statements for the prescribed facilities. OPG has stated that the current segment disclosure in its general purpose audited financial statements is in accordance with Canadian Generally Accepted Accounting Principles, and cannot be changed, since the segmented disclosure is consistent with OPG's management reporting structure. Given that more than 50% of OPG's business is regulated, the Board concludes that the financial statements should reflect this reality. There is no evidence that the regulatory framework for OPG, whereby a significant portion of its business is regulated by the Board, will be changed such that the Board is no longer the regulator. It may be that some investment will be required to provide audited financial statements for the regulated business, but given the size of OPG's regulated business and its significance in the overall Ontario electricity sector, and the expectation of ongoing regulation by the Board, the Board concludes that it is appropriate to continue to require that audited statements for the regulated business be prepared. The Board notes that audited statements for the regulated business were ordered in the prior decision, for reasons related to improved assessment of the revenue requirement, and there was no indication at that time that it would be a one-time requirement. There has been no change in circumstances and no new evidence that would lead the Board to conclude that a change in approach is appropriate. It will be up to OPG to determine how to most efficiently meet this ongoing requirement.

13 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board prepared a report in 2006 establishing the methodology to be used for setting payment amounts for OPG. The report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, issued on November 30, 2006, stated that, “The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula.”

The previous payment amounts proceeding (EB-2007-0905) was the first proceeding for OPG, and was considered under traditional cost of service regulation. While the current application is only the second cost of service application for OPG’s prescribed facilities, both this application and the first one cover an approximately five-year period from 2008 to 2012.

Incentive regulation is an alternative to regular annual cost of service regulation and is generally comprised of a more formulaic or mechanistic approach to adjust revenues or rates for inflation while incentivizing productivity improvements. The process is also intended to avoid lengthy and costly annual hearings under cost of service approaches. The typical approach – and the one that the Board employs for both electricity and natural gas distribution – is that rates are initially set through a cost of service application, after which rates are adjusted annually through the incentive regulation mechanism. After a number of years, the rates, underlying costs and the incentive regulation plan are reviewed and, as necessary, reset. The Board first adopted incentive regulation (also known as performance-based regulation or PBR) for the electricity distribution sector with the 2000 Distribution Rate Handbook. Incentive regulation has been adopted for both electricity and natural gas distribution utilities.

OPG did not address the issue of incentive regulation in its original evidence. However, the Board decided that it would be appropriate to consider the issue in the proceeding. There were two components to this issue:

- When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

- 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?

There was no pre-filed evidence on this matter. The record was completed through responses to interrogatories. There was also discussion of this issue in the technical conference and during the oral hearing.

OPG proposed, in response to an interrogatory, that following the conclusion of the current proceeding, the company would file an application setting out its proposal for incentive regulation. The proposal would be tested in a hearing and OPG would incorporate the results of that decision into its next cost of service application, which would then set base rates for incentive regulation. PWU supported OPG's proposal for development and consideration of incentive regulation, but expressed some reservations about whether incentive regulation is appropriate for OPG for the foreseeable future in light of the development of the long-term energy plan.

CCC was also not convinced that incentive regulation is necessarily appropriate for OPG, but concluded that there may be merit in having some elements of OPG's revenue requirement subject to incentives. CCC suggested that the Board hold a workshop to carefully consider whether incentive regulation could work for OPG.

SEC noted the complexity of OPG's operations and the recent changes in corporate culture and concluded that OPG is not ready for incentive regulation. SEC further submitted that the earliest incentive regulation should be considered is 2014 or 2015.

Board staff submitted that the development of incentive regulation is time and resource intensive and that it would be unrealistic to expect full development of a plan in 2011. Board staff held that the process to develop incentive regulation for OPG's prescribed assets would benefit from stakeholder input early in the process. Board staff observed that a total factor productivity study has not yet been commissioned; external experts have not been retained, and there appear to be no known incentive regulation regimes for utilities which would be analogous to OPG's regulated hydroelectric and nuclear generation businesses. Board staff also suggested that there could be separate incentive regulation plans for the regulated hydroelectric business and the regulated nuclear business because of the different operating characteristics of each.

Board staff provided some options for implementation of incentive regulation. One option would be to have OPG file an application for both IRM and implementation of rates for 2013. OPG argued that the option is impractical because it would not align with OPG's business planning cycle and that the costs would increase due to the resource requirement to respond to directions from the decision and undertake new studies. Another Board staff option would be to file a cost of service application for 2013 and in parallel file an incentive regulation application. In reply, OPG stated that the resource requirement for two applications would be extensive and it did not see how a one-year test period would be in ratepayers' interests.

OPG submitted that a third cost of service application is required to provide a robust starting point for incentive regulation. In its reply argument OPG proposed to file its IRM proposal as part of the cost of service application for 2013-2014; if the IRM proposal was adopted it could take effect in 2015. Alternatively, OPG stated that it could file an IRM proposal in 2013 after the conclusion of the next cost of service application.

Board Findings

The Board notes that its findings on this issue do not impact on the payment amounts arising from this Decision. However, the Board considers it important to give direction to OPG and other stakeholders regarding the future of incentive regulation as a means for setting payments for OPG's prescribed assets.

The Board remains convinced that an incentive regulation mechanism for setting payment amounts will be beneficial in the long-term. As noted in the Natural Gas Forum Report:

> The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.[61]

[61] Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum, (RP-2004-0213), March 30, 2005, p. 22.

The Board is of the view that the benefits of incentive regulation identified in the Natural Gas Forum Report would also apply to OPG, given a suitable design.

The Board concurs with Board staff's submission that adequate time and effort is necessary to develop a suitable plan. OPG itself has acknowledged that the timeline that it first proposed is "aggressive". OPG has acknowledged that the company has not undertaken or commissioned any significant work on incentive regulation at this time.

The Board is not aware of IR plans applicable to generation-only utilities that might help in the development of a plan for OPG. While the Board and the industry have extensive experience with incentive regulation generally, it is not a matter of simply transferring a plan from natural gas or electricity distribution. Aspects of OPG's generation businesses must be suitably studied and accommodated in a plan. For example, development of a suitable X-factor will, in all likelihood, require a productivity study unique to OPG. Such efforts will require considerable time and resources.

The Board finds that, given the current situation, it is not practical to implement incentive regulation in time for implementation for payments for 2013. The Board therefore expects OPG to file another cost of service application for the 2013 and 2014 years.

However, the Board concludes that incentive regulation beginning in 2015 should be considered. To facilitate this, the Board will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG. This review may include options and preferences on the general type(s) of incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. This preliminary process to consider incentive regulation mechanisms in the context of OPG's unique circumstances will allow for input from OPG and all other interested stakeholders.

The outcome of this review will serve as a starting point for OPG's subsequent application for an IRM regime which would commence in 2015. It is expected that the outcome of this review will be available no later than the first quarter of 2012.

Based on this preliminary review, and as a further step in the development of an incentive regulation mechanism, the Board expects OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application, which would be expected in early 2012. OPG's plan would be examined during the proceeding.

Finally, the Board expects OPG to file an application for incentive regulation to be in effect starting in 2015. It is expected that such an application should be filed no later than the fourth quarter of 2013, and would be subject to a hearing in 2014. This would provide time for implementation on January 1, 2015.

The Board believes that this framework and timeline will allow for proper development of an incentive regulation plan while respecting the time and resource commitments necessary for OPG, the Board and stakeholders, and other regulatory activities.

In addition to the preliminary review work that the Board intends to undertake in 2011, the Board also expects OPG to engage stakeholders in meaningful discussions about the proposed incentive regulation mechanism in advance of the actual IRM regime filing.

14 IMPLEMENTATION AND COST AWARDS

14.1 Implementation

OPG proposed that its new payment amounts be made effective March 1, 2011.

On February 17, 2011, the Board issued an interim order making the current payment amounts interim effective March 1, 2011.

The new payment amounts will be made effective March 1, 2011. The Board understands that the IESO can implement this effective date through its billing processes without the necessity for a shortfall payment amounts rider to cover the period between March 1 and the date of the final payment amounts order.

The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

OPG is directed to file the draft payment amounts order by March 21, 2011. Board staff and intervenors shall respond to OPG's draft payment order by March 28, 2011. OPG shall respond to any comments by Board staff and intervenors by April 4, 2011.

14.2 Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Green Energy Coalition, Pollution Probe, School Energy Coalition and Vulnerable Energy Consumers Coalition.

A cost awards decision will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims by April 8, 2011.
2. OPG shall file with the Board and forward to the relevant intervenors any objections to the costs claimed, including any objections to cost claims filed prior to the issuance of this Decision, by April 15, 2011.
3. Intervenors whose costs have been objected to, may file with the Board and forward to OPG any response to the objection by April 21, 2011.

OPG shall pay the Board's costs of and incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, March 10, 2011

ONTARIO ENERGY BOARD

Original signed by

____

Cynthia Chaplin
Presiding Member

Original signed by

____

Marika Hare
Member

Original signed by

____

Cathy Spoel
Member

APPENDIX A

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

OPG filed its application for new payment amounts on May 26, 2010. On June 4, 2010, the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The Board issued Procedural Order No.1 on June 29, 2010, which provided a draft issues list and made provision for an issues conference and submissions on issues. The procedural order made provision for submissions on OPG's request for confidential treatment of certain tax information, and sections of business plans and business case summaries. The procedural order also set out a schedule for the proceeding.

The key milestones in the proceeding are listed below:

- The final issues list was issued along with Procedural Order No. 3 on July 21, 2010.
- Interrogatories were filed by Board staff on July 22, 2010 and by intervenors on July 29, 2010. The majority of responses were filed on August 12, 2010.
- A technical conference was held on August 26, 2010.
- Parties filed evidence on August 31, 2010.
- Interrogatories on evidence were filed on September 7, 2010 and responses were filed on September 14, 2010.
- A settlement conference was held on September 14, 2010, however no settlement was achieved.
- Motions from the Consumers Council of Canada and Canadian Manufacturers & Exports were heard on September 30, 2010.
- The oral hearing took place on 16 days during the period October 4, 2010 to November 26, 2010.
- OPG filed its argument in chief on November 19, 2010.
- Board staff filed its submission on November 30, 2010 and intervenors filed their submissions on December 6 and 7, 2010.
- OPG's reply argument was filed on December 21, 2010.
- An interim order declaring payment amounts interim effective March 1, 2011 was issued on February 17, 2011.

Thirteen procedural orders were issued during the course of the proceeding, some dealing with the schedule of the proceeding, but many dealing with matters of confidentiality, including submissions and decisions on requests for confidential treatment of documents, and submissions and decisions on breaches of confidentiality.

PARTICIPANTS

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding.

Ontario Power Generation Inc.	Charles Keizer Crawford Smith Carlton Mathias Andrew Barrett Barbara Reuber
Board Counsel and Staff	Michael Millar Violet Binette Ben Baksh Richard Battista Russell Chute Chris Cincar Keith Ritchie Duncan Skinner
Association of Major Power Consumers in Ontario	David Crocker Andrew Lord Tom Adams Shelley Grice
Canadian Manufacturers & Exporters	Peter Thompson Vince DeRose Jack Hughes
Consumers Council of Canada	Robert Warren Julie Girvan
Energy Probe Research Foundation	Peter Faye David MacIntosh Norman Rubin Lawrence Schwartz
Green Energy Coalition	David Poch

Pollution Probe Foundation	Basil Alexander Jack Gibbons
Power Workers' Union	Richard Stephenson Alfredo Bertolotti Judy Kwik
School Energy Coalition	Jay Shepherd Mark Garner
The Society of Energy Professionals	Jo-Anne Pickel Mike Belmore Stanley Pui
Vulnerable Energy Consumers Coalition	Michael Buonaguro James Wightman

In addition to the above, the Association of Power Producers of Ontario, Hydro One Networks Inc. and the Ontario Power Authority were registered intervenors in this proceeding. The Independent Electricity System Operator and the Ministry of Energy were registered observers in this proceeding.

WITNESSES

The following OPG employees appeared as witnesses.

Joan Frain	Manager, Water Policy and Planning, Business Services and Water Resources Division
Mario Mazza	Director, Business Support and Regulatory Affairs, Hydro Business Unit
David Peterson	Manager of Market Monitoring
Mark Shea	Asset and Technical Services Manager, Ottawa/St. Lawrence Plant Group
Randy Leavitt	Vice President, Nuclear Finance
Pierre Tremblay	Senior Vice President, Nuclear Programs and Training
Mark Elliott	Senior Vice President of Inspection and Maintenance Services

John Mauti	Director, Nuclear Reporting
Paul Pasquet	Senior Vice President, Pickering B
Michael Allen	Director, Nuclear Programs
Carla Carmichael	Director, Business Planning and Performance Reporting, Nuclear Finance
James Woodcroft	Manager, Outage Programs
Mark Arnone	Vice President, Refurbishment Execution
Fred Dermarkar	Director, Engineering Services
Jamie Lawrie	Director, Investment Management
Nathan Reeve	Vice President, Financial Services
Dietmar Reiner	Senior Vice President, Nuclear Refurbishment
Gary Rose	Director of Planning and Control
Laurie Swami	Vice President, Nuclear Regulatory Programs and Director of Licensing and Environment, Darlington New Nuclear Project
Lorraine Irvine	Vice President, Human Resources Projects
Jong Kim	Chief Technology Officer, Business Services and Information Technology
Tom Staines	Director of Finance – Corporate Functions, Finance
John Lee	Assistant Treasurer
Randy Pugh	Director, Ontario Regulatory Affairs, Regulatory Accounting and Finance
David Bell	Manager, Corporate Accounting
David Halperin	Director, Financial and Business Planning, Corporate Finance
Robin Heard	Vice President, Finance and Chief Controller

Andrew Barrett	Vice President, Regulatory Affairs and Corporate Strategy
Alex Kogan	Manager, Regulatory Finance

OPG also called the following expert witness: John Sequeira of ScottMadden Inc., Kathleen McShane of Foster Associates Inc. and Ralph Luciani of Charles River Associates.

The intervenors called the following expert witnesses:

- Lawrence Kryzanowski of Concordia University and Gordon Roberts of York University appearing for Pollution Probe
- Paul Chernick of Resource Insight Inc. appearing for GEC
- Bruce Sharp of Agent Energy Advisors Inc., whose evidence was entered by written affidavit, for CME

APPENDIX B

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

APPROVALS SOUGHT BY OPG IN EB-2010-0008

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- The 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 period of January 1, 2011 through December 31, 2012 (the "test period") as set out in Ex. I1-T1-S1.

- The approval of a rate base of $3,803.4M and $3,787.4M for the regulated hydroelectric facilities for the years 2011 and 2012, respectively and $4,041.3M and $4,150.8M for the nuclear facilities for the years 2011 and 2012, respectively, as summarized in Ex. B1-T1-S1.

- The inclusion of construction work in progress ("CWIP") amounts for the Darlington Refurbishment Project of $125.5M in 2011 and $306.0M in 2012 in the rate base for the nuclear facilities and recovery of the associated cost of capital as presented in Ex. D2-T2-S2.

- Approval of a production forecast of 38.4 TWh for the test period for the regulated hydroelectric facilities and 98.9 TWh for the test period for the nuclear facilities. The production forecast is presented in Exhibit E.

- Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base of 7.18 per cent and 7.21 per cent for 2011 and 2012, respectively, including a rate of return on equity ("ROE") forecast of 9.85 per cent, as presented in Ex. C1-T1-S1.

- Approval of a payment amount for the regulated hydroelectric facilities, effective March 1, 2011 of $37.38/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the "hourly volume") for each hour of that month.

Amended: 2010-10-08
EB-2010-0008
Exhibit A1
Tab 2
Schedule 2
Page 2 of 3

Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market. The payment amount for the regulated hydroelectric facilities is set out in Ex. I1-T2-S1.

- Approval of a payment amount for the nuclear facilities, effective March 1, 2011 of $55.34/MWh.

- Approval for recovery of the audited December 31, 2010 variance and deferral account balances for the regulated hydroelectric and nuclear facilities as described in Ex. H1-T1-S2 and disposition, beginning March 1, 2011, at a rate derived as described in Ex. H1-T2-S1.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
  - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
  - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
  - A variance account to record the deviation from forecast capital and non-capital costs and firm financial commitments associated with work to increase the output of, refurbish or add operating capacity to a regulated facility.
  - A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities.
  - A variance account to record the deviation between actual and forecast nuclear fuel costs.
  - A deferral account to record non-capital costs associated with the planned return-to-service of units at the Pickering A Generating Station.

- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities.
- A variance account to record the difference between forecast and actual IESO non-energy charges incurred by the regulated hydroelectric and nuclear facilities.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-T3-S1.

- An order from the OEB declaring OPG's current payment amounts interim as of March 1, 2011, if the order or orders approving the payment amounts are not implemented by March 1, 2011.

–

APPENDIX C

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

DECISION ON MOTIONS, OCTOBER 4, 2010

DECISION ON CCC AND CME MOTIONS

Transcript: Oral Hearing, Volume 1, October 4, 2010, page 113

The Board sat on Thursday, September 30th, to hear motions by CCC and CME. Both motions sought the production of materials presented to the OPG board of directors in the period between April 1, 2010 and May 26, 2010.

The Board has decided not to order production of the materials sought in the CME and CCC motions. In the Board's view, these materials are not relevant to the determination of the issues before the Board in this proceeding. The Board will make its decision on the application and supporting materials filed by the applicant and the evidence of intervenors, all of which is subject to cross-examination.

This evidence goes to the financial and operational impacts of the application and of the alternatives which have been considered.

The material which has been sought through the motions includes the communication between OPG's management and its board of directors, seeking approval to file the application, delegated authority to deal with the proceeding, and the analysis of "likely prospects for success." This material does not form part of the application and does not enhance nor detract from the merits of the application.

The evidence is that no changes to the business plans and budgets which underpin the application were sought or made as a result of the board of directors' meeting. These plans and budgets have been filed.

Intervenors can explore, through the witness, whether alternatives to the application should have been considered, and the impacts of OPG's choices. None of this relies on what management presented to the board of directors.

Having found that the materials are not relevant and need not be produced, the question of privilege will not be addressed.

That concludes the Board's decision, and subject to any questions, we can continue with the cross-examination.

APPENDIX D

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

SECTION 78.1 OF THE *ONTARIO ENERGY BOARD ACT, 1998*, S.O.1998, C.5 (SCHEDULE B)

Excerpt: Section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O.1998, c.15 (Schedule B).

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

APPENDIX E

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

ONTARIO REGULATION 53/05

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

   (i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.
2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
   i. the costs were prudently incurred, and
   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
   i. capital cost allowances,
   ii. the revenue requirement impact of accounting and tax policy decisions, and
   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.
7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,
   i. return on rate base,
   ii. depreciation expense,
   iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

APPENDIX F

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

FINAL ISSUES LIST

Ontario Power Generation Inc.
2011-2012 Payment Amounts for
Prescribed Generating Facilities
EB-2010-0008

FINAL ISSUES LIST

1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

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

1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

2. RATE BASE

2.1 What is the appropriate amount for rate base?

2.2 Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 What is the appropriate capital structure and rate of return on equity?

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

3.3 Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 Do the costs associated with the regulated hydroelectric projects, that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section? Are any additional costs prudent?

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

4.3 Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Nuclear

4.4 Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section? Are any additional costs prudent?

4.5 Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

4.6 Are the proposed in-service additions for nuclear projects appropriate?

4.7 Is the proposed treatment for the Pickering Units 2 and 3 isolation project costs appropriate?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Is the proposed regulated hydroelectric production forecast appropriate?

Nuclear

5.2 Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG’s hydroelectric facilities reasonable?

Nuclear

6.3 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG’s nuclear facilities reasonable?

6.5 Has OPG responded appropriately to the observations and recommendations in the benchmarking report?
6.6 Is the forecast of nuclear fuel costs appropriate?
6.7 Are the proposed expenditures related to continued operations at Pickering B appropriate?

Corporate Costs

6.8 Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?
6.9 Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?
6.10 Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

Other Costs

6.11 Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?
6.12 Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

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

Nuclear

7.2 Are the proposed test period nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

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

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

9. DESIGN OF PAYMENT AMOUNTS

9.1 Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

9.2 Is the hydroelectric incentive mechanism appropriate?

10. DEFERRAL AND VARIANCE ACCOUNTS

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

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

10.3 Is the disposition methodology appropriate?

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

10.5 Should the proposed variance account related to IESO non-energy charges be established?

10.6 What other deferral and variance accounts, if any, should be established for the test period?

11. REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 What reporting and record keeping requirements should be established for OPG?

12. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, November 30, 2006, stated that, “The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

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?

APPENDIX G

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

MEMORANDUM OF AGREEMENT BETWEEN OPG AND THE PROVINCE OF ONTARIO

Filed: 2010-05-26
EB-2010-0008
Exhibit A1-4-1
Attachment 2

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU 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.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of

Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

Filed: 2010-05-26
EB-2010-0008
Exhibit A1-4-1
Attachment 2

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

4

APPENDIX H

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

CALCULATION OF RETURN ON EQUITY BASED ON NOVEMBER 2010 DATA

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: November 2010

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Nov-10	2.84	3.47	4.97	0.64	1.50
2	2-Nov-10	2.87	3.48	4.92	0.61	1.43
3	3-Nov-10	2.87	3.50	4.94	0.63	1.44
4	4-Nov-10	2.81	3.48	4.92	0.66	1.44
5	5-Nov-10	2.85	3.49	4.95	0.64	1.47
6	6-Nov-10					
7	7-Nov-10					
8	8-Nov-10	2.89	3.51	4.94	0.62	1.43
9	9-Nov-10	2.98	3.57	4.97	0.60	1.40
10	10-Nov-10	2.97	3.59	4.94	0.62	1.35
11	11-Nov-10	2.97	3.59	4.94	0.62	1.35
12	12-Nov-10	3.02	3.63	4.97	0.61	1.34
13	13-Nov-10					
14	14-Nov-10					
15	15-Nov-10	3.15	3.73	5.08	0.58	1.36
16	16-Nov-10	3.08	3.68	5.02	0.60	1.34
17	17-Nov-10	3.10	3.67	5.02	0.58	1.35
18	18-Nov-10	3.12	3.67	5.04	0.54	1.38
19	19-Nov-10	3.14	3.62	5.03	0.47	1.42
20	20-Nov-10					
21	21-Nov-10					
22	22-Nov-10	3.09	3.59	5.00	0.50	1.42
23	23-Nov-10	3.11	3.60	5.04	0.49	1.45
24	24-Nov-10	3.19	3.65	5.05	0.46	1.40
25	25-Nov-10	3.17	3.64	5.04	0.47	1.40
26	26-Nov-10	3.11	3.57	5.02	0.46	1.45
27	27-Nov-10					
28	28-Nov-10					
29	29-Nov-10	3.09	3.52	4.98	0.44	1.46
30	30-Nov-10	3.06	3.48	4.95	0.42	1.47
31						
		3.02	3.58	4.99	**0.556**	**1.410**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Publication Date:	November 8, 2010		
	3-month	12-month	Average	
November 2010	2.800	3.300 ❸	**3.050**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	❸	3.050	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	❶	0.556	%
Long Canada Bond Forecast (LCBF)	❹	**3.606**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75	%
Change in Long Canada Bond Yield Forecast from September 2009				
LCBF (November 2010) (from Step 3	❹	3.606 %		
Base LCBF		4.250 %		
Difference		-0.644 %		
0.5 X Difference			-0.322	%
Change in A-rated Utility Bond Yield Spread from September 2009				
A-rated Utility Bond Yield Spread (November 2010) (from Step 1)	❷	1.410 %		
Base A-rated Utility Bond Yield Spread		1.415 %		
Difference		-0.005 %		
0.5 X Difference			-0.002	%
Return on Equity based on November 2010 data			**9.43**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for November 2010 (from Step 3)	❹	3.606	%
A-rated Utility Bond Yield Spread November 2010 (from Step 1)	❷	1.410	%
Deemed Long-term Debt Rate based on November 2010 data		**5.02**	%

References on Calculation Methods:

- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.