ONTARIO POWER GENERATION

EB-2010-0008

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Argument-in-Chief

Ontario Power Generation Inc.

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TABLE OF CONTENTS

1.0 OVERVIEW 1

2.0 BUSINESS PLANNING AND AND CONSUMER IMPACTS 2
2.1 Introduction 2
2.2 Business Planning – Process Overview 2
2.3 2010 - 2014 Business Planning Objectives 3
2.4 Response to Customer Concerns 4

3.0 HYDROELECTRIC 5
3.1 Hydroelectric Operating Costs 5
3.2 Hydroelectric Capital Projects 8
3.3 Hydroelectric Production Forecast 10
3.4 Hydroelectric Other Revenues 12
3.5 Hydroelectric Incentive Mechanism 15

4.0 NUCLEAR 16
4.1 Nuclear Benchmarking and Business Planning 16
4.2 Nuclear OM&A, Fuel, Pickering B Continued Operations and Nuclear Non-Energy Revenues 21
4.3 Nuclear Capital Projects 32
4.4 Nuclear Production Forecast 37
4.5 Darlington Refurbishment and New Nuclear at Darlington 39

5.0 COMPENSATION AND BENEFITS 46
5.1 OPG's Employees 46
5.2 Compensation for OPG's Unionized Employees 47
5.3 Management Group Compensation 49
5.4 Benefits 50
5.5 Pension and Other Post Employment Benefits 51

6.0 CORPORATE FUNCTION COSTS AND COST ALLOCATION 52
6.1 Introduction 52
6.2 OPG's Corporate Function Costs 53
6.3 Corporate Cost Allocation 54
6.4 Asset Service Fee 56

7.0 CENTRALLY HELD COSTS, OTHER OPERATING COSTS AND BRUCE LEASE COSTS AND REVENUES 57
7.1 Centrally Held Costs 57
7.2 IESO Non-Energy Charges 58
7.3 Other Operating Costs 59

8.0 COST OF CAPITAL 63
8.1 Introduction 63
8.2 Fair Return Standard 64
8.3 The Stand-Alone Principle 65
8.4 Return On Equity 65
8.5 Cost of Debt 65
8.6 Technology Specific Capital Structures 68

9.0 NUCLEAR LIABILITIES 70
9.1 Background 70
9.2 Application of the Approved Methodology to the Prescribed and Bruce Facilities 71
9.3 Impacts of the Darlington Refurbishment Project ON Nuclear Liabilities 72

10.0 RATE BASE 72
10.1 Prescribed Facility Rate Base 72
10.2 CWIP in Rate Base 74

11.0 DEFERRAL AND VARIANCE ACCOUNTS 78
11.1 Introduction 79
11.2 Existing Deferral and Variance Accounts 80
11.3 OPG's Proposal for Clearning the Deferral and Variance Account Balances 89
11.4 Continuation and Establishment of New Accounts 90

12.0 DESIGN OF PAYMENT AMOUNTS 97
12.1 Implementation 98

13.0 REPORTING AND RECORD-KEEPING REQUIREMENTS 98

14.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS 99

1.0 OVERVIEW

This is OPG's second application for payment amounts for the generating facilities prescribed under Section 78.1 of the Ontario Energy Board Act, 1998. In the three years since OPG's last application, the company has focused on cost control and on performance improvement while maintaining its commitment to safety and reliability.

OPG has a single shareholder – the Province of Ontario. OPG is incorporated under the *Ontario Business Corporations Act* and OPG's Board of Directors is appointed by the Province with a mandate to operate the company as a commercial enterprise. To do that, OPG must receive just and reasonable payment amounts for its prescribed facilities that cover the costs of operating and maintaining these assets and making new investments in them, and allow the company to earn a fair return on invested capital.

OPG's prescribed facilities are forecast to produce approximately 69 TWh per year over the test period. This represents almost 48 per cent of Ontario's total energy demand (Ex. A1-T3-S1, page 1). The prescribed facilities are among the lowest cost generation sources available to Ontario consumers. The payment amounts requested in this Application are necessary to ensure the continued safe, reliable and efficient operation of these major, low-cost contributors to Ontario's electricity supply.

Cost control is a prominent feature of OPG's business planning and of this application. Through the use of benchmarking, OPG has initiated activities to continue controlling costs and improve the performance of its nuclear facilities as discussed in Ex. F2-T1-S1. OPG's hydroelectric facilities already benchmark well on both cost and performance as discussed in Ex. F1-T1-S1. OPG proposes to continue the reinvestment and OM&A expenditures necessary to maximize the efficient production from its prescribed facilities.

OPG also presents new initiatives in this application to ensure that the prescribed facilities continue to supply reliable and affordable power into the future. The decision to proceed with the Darlington Refurbishment project and to commence the project's definition phase will allow Darlington to operate for an additional 30 years as discussed in Ex. D2-T2-S1. Continuing to operate Pickering B for an additional four years beyond its nominal end of life will provide additional baseload generation during a period of intensive nuclear refurbishment at a cost lower than other generation sources (Ex. F2-T2-S3).

OPG's is seeking an overall increase of 3.9 per cent on its payment amounts (Ex. L-12-001). The current payment amounts will have been in effect for almost three years by the time new payment amounts come into effect on March 1, 2011 (Tr. Vol. 15, page 10). Even when considering the impact of variance and deferral accounts, which largely address under-recoveries embedded in the previous payment amounts, the increase that OPG is seeking is approximately 6.2 per cent (Ex. A1-T3-S1, page 3; Tr. Vol. 1, page 5). This is equivalent to about two per cent a year over the past three years. In terms of consumer impact, this increase would result in an estimated increase of $1.86 per month or about 1.7 per cent on the bill of a typical residential consumer (Ex. I1-T1-S2, page 1).

2.0 BUSINESS PLANNING AND AND CONSUMER IMPACTS

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

Issue 1.3 - Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

2.1 INTRODUCTION

This Application is based on the forecasts contained in OPG's 2010 - 2014 Business Plan. This plan was developed following a robust planning and budgeting process, designed to contain costs while ensuring the safe and reliable production of electricity. The result is an application that gives rise to a modest increase over the payment amounts approved for 2008. OPG submits that its request is reasonable and should be approved.

2.2 BUSINESS PLANNING – PROCESS OVERVIEW

OPG's business planning process is a decentralized annual process undertaken within a consistent corporate framework of strategic objectives, resource guidelines, and costing assumptions. The key elements of this corporate framework are identified to the business units through Business Planning Instructions provided by OPG's finance function. Within this framework, the individual business units develop their specific strategic and performance objectives, key risks and mitigation initiatives, and then identify and plan the work required to achieve these objectives (Ex. A2-T2-S1, page 1).

To aid in the development of consistent business plans and provide an overall plan for the corporation certain additional activities are under taken on a centralized basis. These include:

- The development of the consolidated revenue, sales and production forecast by OPG's Energy Markets business unit, along with associated scenarios and sensitivities. This forecast incorporates key production and reliability parameters from the Nuclear and Hydroelectric business units.
- The preparation of a consolidated financial outlook by the Finance business unit, based on inputs received from across the organization.
- Consideration of alternative planning scenarios once the base case forecast has been established, which relate to the particular operational and/or financial issues facing OPG.

Individual business unit plans are reviewed with the President and Chief Executive Officer ("CEO") through a series of presentations, usually during September and early October. Business units incorporate feedback and redirection from these sessions into their updated submissions, typically in early November.

The draft consolidated business plan, based on updated November submissions, is reviewed by OPG senior management. The plan is also reviewed with shareholder representatives. The 2010 - 2014 Business Plan was submitted to the Board in November 2009 for approval. Once approved by OPG's Board of Directors, the Corporate Business Plan was submitted to the shareholder for concurrence, which was received (J9.10). As discussed below, in May 2010, OPG made certain changes to its OEB application to reduce the impact on customers. They were reviewed and approved by OPG's Board of Directors and received shareholder concurrence.

2.3 2010 - 2014 BUSINESS PLANNING OBJECTIVES

The 2010 - 2014 Business Planning Instructions set the context for the planning process (Ex. A2-T2-S1, Attachment 1). The instructions recognized the significant internal challenges facing OPG as it enters a transition phase for much of its generation, and the external challenge as its customers face significant economic turmoil. The 2010 - 2014 Business Plan (J10.1) covers a critical period for OPG, during which it will reshape its generation portfolio to meet future needs. Major initiatives that impact OPG's regulated operations include: the Darlington

Refurbishment project, the Pickering B Continued Operations initiative and incorporating a "gap-based" approach to business planning in Nuclear.

In response to the financial environment, business units were directed to be particularly aggressive in managing their costs while maintaining their critical performance objectives. Specifically, the business planning guidelines for 2010 required an $85M reduction in OM&A, compared to previously planned levels for that year. Management's commitment to this reduction helped offset the loss in revenue resulting from the deferral of the rate application.

Guidelines for subsequent years in the plan recognized the need to maintain strict expenditure control, and included:

- The continuation, into future years, of the 2010 cost reductions implemented by Nuclear;
- A direction to all corporate support groups that they freeze their future years' expenditure at 2010 levels.

OPG's business units responded by submitting plans that have met the financial targets. Cost reductions are forecast to be achieved, and in the aggregate, estimated savings across all business units are $278M in 2011 - 2012, compared to the previous business plan. At the same time, OPG faced a number of unavoidable cost increases for new initiatives, such as increased expenditures on Pickering B Continued Operations. These increases total $150M during 2011 - 2012, with the result that in 2011 - 2012 the net total business unit expenditures are forecast to be $128M lower than in OPG's previous business plan.

2.4 RESPONSE TO CUSTOMER CONCERNS

In late March of this year, OPG initiated a stakeholder session to review its then contemplated application. It also issued a press release outlining the anticipated content of its application.

In response to public concern, OPG senior management decided to delay the filing of the application and to consider whether there were aspects of that application that could reasonably be adjusted (Tr. Vol. 15, page 15).

Ultimately, OPG elected to (i) delay the implementation of rates to March 1, 2011; and (ii) extend the period of recovery for the Tax Loss Variance Account from 24 to 46 months. These changes were approved by the OPG Board of Directors at its May 20 meeting, and the Application was filed shortly thereafter (Tr. Vol. 15, pages 16-17).

OPG did not revise its work programs or budgets in its 2010 - 2014 Business Plan (Ex. L-4-001). This was not necessary or appropriate owing to the careful attention already paid to cost containment throughout the business planning process and the significant cost reductions achieved through that process (Tr. Vol. 15, pages 16-17).

OPG believes that its application reflects a realized commitment to limit those costs under its control, and is reasonable. The current payment amounts will have been in effect for almost three years by the time the payment amounts resulting from this proceeding are in place. Yet, the combined effect of the new payment amounts and riders is, as referred to above, an average increase of 6.2 per cent, which represents an increase of just 1.7 per cent on the typical residential customer's bill. 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 effects.

On October 27, the OEB announced three policy initiatives directed at how to manage the pace of rate or bill increases for consumers. It is through the OEB's integrated policy framework for the electricity sector that issues of total bill impact should be considered and not through individual rate applications.

3.0 HYDROELECTRIC

3.1 HYDROELECTRIC OPERATING COSTS

> **Issue 6.1** - Is the test period operations, maintenance and administration budget for the regulated hydroelectric facilities appropriate?

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

3.1.1 Introduction

The regulated hydroelectric operating costs include base and project OM&A, Gross Revenue Charges ("GRC"), the share of corporate support and centrally held costs attributable to the regulated hydroelectric facilities and the asset service fee. This section addresses regulated hydroelectric OM&A and the GRC. The corporate and centrally held cost categories are more fully discussed at Sections 6 and 7.1 below.

OPG submits that the total hydroelectric OM&A budget, which is forecast to decrease over the test period, is reasonable and should be approved by the OEB.

OPG's forecast hydroelectric OM&A and GRC costs in millions are as follows:

	2011	**2012**
Base OM&A	$ 68.7	$ 62.2
Project OM&A	$ 9.7	$ 10.0
GRC	$257.1	$252.2
TOTAL	**$335.5**	**$324.4**

3.1.2 Base OM&A

The regulated hydroelectric OM&A budget is established through the annual business planning process (see Ex. A2-T2-S1 and Ex. F1-T1-S1). The 2010 - 2014 process included a focus on prudent management of costs while properly maintaining the hydroelectric assets. (Tr. Vol. 2, page 31).

Base OM&A expenditures for OPG's regulated hydroelectric facilities are attributed on a work program basis, consistent with how costs are incurred. Base OM&A budgets are attributed to each of the plant groups based on the following work programs: operations, maintenance, and administration support (Ex. F1-T2-S1). Overall, base OM&A is forecast to remain relatively stable over the test period at 2009 levels, with cost increases in 2011 associated with OPG's bridge divestiture program offset by comparable reductions in 2012 (Ex. F1-T2-S1, Table 1).

In addition to the costs incurred within the plant groups, certain other costs incurred to support the regulated hydroelectric facilities are provided on a centralized basis. The support costs included in regulated hydroelectric OM&A include directly assigned and allocated costs from OPG's corporate functions, centrally held costs, hydroelectric central support group costs and, for the Saunders facility only, which is part of the Ottawa-St. Lawrence Plant Group, an allocated portion of that plant group's common support costs (Ex. F1-T2-S1, pages 9-10).

As part of OPG's overall benchmarking effort, Hydroelectric benchmarks reliability, cost and safety performance with comparable businesses (Ex. F1-T1-S1, page 11). Benchmarking data provides a starting point to compare the costs and reliability of OPG's regulated hydroelectric facilities with those of other hydroelectric facilities. Because of the differing geographic locations and distribution of the plants, as well as differences in regulatory regimes, absolute comparisons cannot be made between the regulated hydroelectric station costs and other stations. Overall, however, OPG's hydroelectric facilities demonstrate strong benchmarking results. The availability and reliability of the regulated facilities is generally better than the EUCG and CEA benchmarks (Ex. F1-T1-S1, page 16), while remaining cost competitive (Ex. F1-T1-S1, page 18; J1.9).

OPG's Hydroelectric business reviews the benchmarking results and best practices annually as part of the business planning process and applies new practices and associated cost reductions as appropriate. Examples of best practices that have been implemented over the past ten years are shown at Ex. F1-T1-S1, page 11.

Another significant cost for the regulated hydroelectric facilities is the GRC. All aspects of GRC payments made by OPG to the Province are governed by legislation or regulation. As such, OPG does not control the GRC charges associated with its regulated hydroelectric facilities (Ex. F1-T4-S1, page 1). The GRC is charged to the owners of hydroelectric generating stations under Section 92.1 of the *Electricity Act* and is comprised of a property tax component payable to the Ministry of Finance or the Ontario Electricity Financial Corporation, as well as a water rental component payable to the Ministry of Finance for holders of water power leases (Ex. F1-T4-S1, pages 1-2). O. Reg. 124/02 establishes the water rental component at 9.5 per cent, while the property tax component is tiered and dependent on annual production levels. (Ex. F1-T4-S1, page 3, Chart 1). In addition, OPG pays the St. Lawrence Seaway Management Company for conveying water through the Welland Canal (Ex. F1-T4-S1, page 4).

3.1.3 Project OM&A

OPG's OM&A projects differ from base OM&A work because they have a non-recurring scope of work, a generally longer timeline and a higher materiality threshold. OM&A projects are distinct from capital projects because they do not meet the criteria for capitalization under OPG's capitalization policy (see Ex. A2-T2-S1). However, the management of OM&A projects is identical to that of capital projects (Ex. D1-T1-S1). Hydroelectric plant groups manage both capital and OM&A projects in a project listing that forms the basis for budgeting during the annual business planning process. Projects are identified through routine inspections, engineering reviews and detailed plant condition assessments. The process for identifying and prioritizing hydroelectric projects is described in Ex. F1-T1-S1.

OM&A projects are mainly sustaining expenditures above a materiality threshold (typically $50k) for repairs and maintenance, such as major unit overhauls. In addition to maintenance projects for production equipment, there are many projects related to aging civil structures. Project OM&A expenditures on production equipment include the unit rehabilitation program at Sir Adam Beck Pump Generating Station, which is expected to start in 2011 (Ex. F1-T3-S1, page 1).

OPG's forecast of project OM&A spending represents a reasonable level of necessary expenditures and should be approved.

3.2 HYDROELECTRIC CAPITAL PROJECTS

Issue 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?

Issue 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?

Issue 4.3 - Are the proposed in-service additions for regulated hydroelectric projects appropriate?

3.2.1 Hydroelectric Capital Spending

Capital expenditures for the regulated hydroelectric facilities are forecast to be $328.0M and $235.8M in 2011 and 2012, respectively (Ex. D1-T1-S1, Table 1). There are no Section 6(2)4, O. Reg. 53/05 projects coming into service in the test period, but the Niagara Tunnel project, which is forecast to enter rate base in 2013, is subject to Section 6(2)4 of O. Reg. 53/05.

OPG's capitalization policy (Ex. A2-T2-S1) is used to determine which regulated hydroelectric projects are capital projects and which fall within project OM&A. Under this policy, capital projects satisfy the following criteria: (a) provide future benefits beyond one year, (b) involve the purchase of a new asset or the increase in the life or output of an existing asset, and (c) meet or exceed the materiality threshold (i.e., $200k per generating unit).

Hydroelectric uses a structured portfolio approach to identify and prioritize projects (Ex. F1-T1-S1). Ultimately, the project portfolio is approved through OPG's business planning process (discussed in Section 2 above), which includes approval of the capital project budget (as well as the project OM&A budget) by OPG's Board of Directors. Prior to beginning work on a project, funds are released through the approval of a business case summary ("BCS").

OPG's planned capital expenditures for the regulated hydroelectric facilities during the test period are dominated by the Niagara Tunnel project. The prudence of the expenditures relating to this project is not an issue in this proceeding. As directed by the OEB, OPG provided a status report in respect of the project (Ex. D1-T1-S2, Attachment 1; JX2.4).

Capital spending over the test period, aside from the Niagara Tunnel, is largely associated with other Niagara Plant Group facilities (Ex. D1-T1-S1, Table 1). Of this spending, the majority relates to necessary rehabilitation work on units G3 and G10 at the Sir Adam Beck I Generating Station and the penstock replacement project at DeCew Falls I.

Comprehensive descriptions and listings of regulated hydroelectric capital projects over the test period can be found at Ex. D1-T1-S2. This exhibit also presents in-service additions for the bridge year and test period, and explains changes from OPG's EB-2007-0905 application.

3.2.2 Hydroelectric In-Service Additions

Through its requested approval of rate base, OPG is seeking approval of regulated hydroelectric in-service additions of $60.9M, $42.9M and $51.5M for 2010, 2011 and 2012, respectively (Ex. D1-T1-S2, Tables 1-5). OPG submits that its capital spending has been prudent and the in-service additions to rate base should be approved.

The largest test period in-service additions are the unit upgrades at Sir Adam Beck I, and the replacement of generator protection and controls at R.H. Saunders (Ex. D1-T1-S2, Section 3.1). Other significant in-service additions are as follows:

- **SAB I Unit G9 Rehabilitation** - The total cost of this project is $32.1M. The project is expected to increase the capacity of Unit G9 by approximately 10MW. The project commenced in 2008 and is projected to come into service by December 2010. The project is on schedule and on budget.

- **St. Lawrence Power Development Visitor Centre -** This project came into service in August of this year, on schedule and on budget at $12.6M. The project involved the construction of a new Visitor Centre adjacent to R.H. Saunders Generating Station. The Centre replaces the original visitor centre that was closed in 1992 and could not be reopened due to post-9/11 security concerns. The Centre provides 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 (Ex. L-1-018; Tr. Vol. 1, pages 47-52, 148-156).

3.3 HYDROELECTRIC PRODUCTION FORECAST

Issue 5.1 - Is the proposed regulated hydroelectric production forecast appropriate?

3.3.1 Introduction

OPG is seeking approval of a test period regulated hydroelectric forecast of 38.4 TWh (19.4 TWh in 2011 and 19.0 TWh in 2012) for the regulated hydroelectric facilities (Ex. E1-T1-S1, Table 1). OPG's production forecast for the regulated hydroelectric facilities is based on a robust methodology which has been appropriately applied to the test period.

3.3.2 Forecast Methodology

The regulated hydroelectric production forecast is impacted by water availability. OPG seeks to optimize the use of available water while meeting safety, legal, environmental, and operational requirements. The availability of water is affected by meteorological conditions, particularly precipitation and evaporation. The forecast methodology accounts for operational strategies designed to maximize use of available water and minimize spill (unutilized water flow) (Ex. E1-T1-S1, page. 1).

Computer models are used to derive flow and production forecasts for the regulated hydroelectric facilities. These models have proven to be 90 per cent accurate and statistical analysis shows no bias in the flow forecasts. (Ex. L-4-023; Tr. Vol. 1, pages 60-61). Forecast monthly water flows, generating unit efficiency ratings, and planned outage information are used to convert forecast water availability into forecast energy production (Ex. E1-T1-S1, pages 2-5). Within these constraints, the forecast assumes all available water is used for production (Tr. Vol. 2, page 100). The Hydroelectric Water Conditions Variance Account captures the revenue and cost impacts of differences between forecast and actual water conditions.

With the exception of the adjustment to reflect the impact of forecast surplus baseload generation discussed below, the regulated hydroelectric production forecast methodology is essentially the same as the methodology that was approved by the OEB in EB-2007-0905.

3.3.3 Surplus Baseload Generation

Surplus baseload generation ("SBG") is a condition that occurs when electricity production from baseload facilities is greater than Ontario demand. During 2009, SBG was more prevalent in Ontario than it had been for many years (even then, the overall impact of the generation surplus was mitigated by a vacuum building outage at OPG's nuclear facilities) (Tr. Vol. 2, page 45). Increased SBG was due to reduced electricity demand and an increase in available electricity supply, both of which are outside of OPG's control. The forecast production values in EB-2007-0905 did not take into consideration the decreased production attributable to SBG experienced in 2009 (Ex. E1-T1-S1, page. 5).

While SBG is an Ontario-wide phenomenon to be managed by the IESO, practically, OPG does have to take certain actions to mitigate SBG, where possible (Ex. L-1-036). OPG decides which of its facilities are best equipped to assist in the mitigation of SBG primarily from a safety and operational perspective, not on an economic basis (Tr. Vol. 1, page 73, line 5 to page 74, line 9).

From a safety and operational perspective, for OPG, SBG is best managed at the Sir Adam Beck facilities. Hydroelectric facilities are designed to be manoeuvred while nuclear reactors are not. In addition, at Beck, water can safely be spilled over the Niagara Falls. For other hydroelectric facilities spilling can raise safety concerns because spillways are often in locations where people tend to congregate for recreational and other uses. Safety concerns must be addressed through procedures such as inspection of spillways prior to spill (Tr. Vol. 2, pages 116-117).

OPG forecasts that significant SBG will continue through the test period based on anticipated levels of Ontario electricity demand and generation supply. Consequently, a forecast SBG adjustment has been integrated into the regulated hydroelectric production forecast totals for the test period, and itemized separately in line 21 of Ex. E1-T1-S2, Table 1. The specific SBG adjustments included in the forecast are: 0.5 TWh in 2011, and 0.8 TWh in 2012. The main driver of this adjustment is the planned expansion of renewable wind generation in Ontario. This new generation accounts for 0.8 of the 1.3 TWh adjustment outlined above (J2.3).

OPG's SBG forecast is based on the best information available at the time it was produced and no alternative forecast has been offered. While reasonable people can disagree over the specific forecast level of SBG anticipated in the test period, OPG submits that it would be unreasonable for the OEB to ignore the reality that SBG is now a significant feature of the Ontario marketplace that is unlikely to abate in the future, particularly in light of the continued growth in wind power (J2.2). If, however, the OEB has concerns about the forecast level of SBG, then it should establish a variance account to recover any difference between actual and forecast SBG. In this way, both OPG and ratepayers will be protected against the risk of over/under recovery associated with SBG; a fair result given that SBG is beyond OPG's control.

3.4 HYDROELECTRIC OTHER REVENUES

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

3.4.1 Introduction

Consistent with the treatment approved by the OEB in EB-2007-0905, OPG proposes that revenues (less costs) from the following hydroelectric ancillary services be applied as an offset to the hydroelectric revenue requirement:

- Black start capability,
- Operating reserve,
- Reactive support/voltage control service, and
- Automatic generator control ("AGC").

Provision of the above services is integral to the operation of OPG's prescribed assets. A forecast of these other revenues for the test period is included in the calculation of the revenue requirement for the regulated hydroelectric facilities. Differences between this forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric Sub Account, as approved by the OEB in the last payments amounts case (Ex. G1-T1-S1, pages 1-2).

In addition, OPG earns other revenues from Segregated Mode of Operation ("SMO") and Water Transactions ("WT") which are similarly included as an offset to the revenue requirement.

Overall, the forecast of other revenues associated with the regulated hydroelectric facilities for the test period is $44.9M and $46.2M in 2011 and 2012, respectively (Ex. G1-T1-S1, Table 1). The forecast reflects a decrease compared to the previous test period owing primarily to changes proposed in the forecast revenues for SMO and WT.

3.4.2 Segregated Mode of Operation

Segregated mode of operation transactions occur at R.H. Saunders Generating Station and are accommodated by segregating units from R.H. Saunders to Hydro-Québec's control area. Prior to entering into a SMO configuration, OPG must seek approval from the IESO, which can be refused or revoked at any time.

SMO is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods.

The OEB's Decision with Reasons in EB-2007-0905 specified that the average of the previous three historical years of actual net revenue values for SMO (i.e., 2005, 2006, and 2007) be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period.

A new high voltage direct current transmission interconnection ("DC intertie") between Ontario and Québec partially came into commercial service in July 2009. The full transfer capacity of this line entered service in November, 2009. The impact of the DC intertie on SMO revenues to date has been significant. Actual SMO revenues in 2009 were $10.1M lower than in 2008 (Ex. G1-T1-S1, page 6).

The reduction in SMO revenues experienced in the last six months of 2009 is expected to be permanent – revenues will not return to pre-DC intertie levels. Actual experience over the last year in 2010 confirms this view (Tr. Vol. 1, page 41). Therefore, the use of the three year historical average would significantly overstate the revenues anticipated in the test period. To more accurately forecast these revenues, OPG is proposing to use the actual SMO results during the second half of 2009 to forecast the revenues over the test period (Ex. G1-T1-S1, page 6).

3.4.3 Water Transactions

Water transactions between the New York Power Authority ("NYPA") and OPG provide an opportunity to maximize use of the available water by allowing either OPG or NYPA to use a portion of the other's share of the water available for power generation (Ex. G1-T1-S1, page 6). In return, the entity that uses the water provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity. Since the opening of electricity markets in Ontario and New York, water transactions are settled financially. The majority of water transactions are for the purposes of salvaging the water that otherwise would be spilled over Niagara Falls or to facilitate ice control procedures.

As with SMO revenues, the OEB's Decision in EB-2007-0905 specified that the average of the previous three historical years (i.e., 2005, 2006, and 2007) of actual net water transactions revenues be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period. However, forecasts based on averages of past three years' results do not incorporate recent market trends, such as continued low spot market prices. These trends are expected to influence future revenues. Throughout 2009 low market prices reduced water transactions revenues and these low market prices are expected to continue during the test period (Ex. G1-T1-S1, pages 7-8; Ex. G1-T1-S2, Table 1).

Accordingly, OPG proposes that test period water transactions annual net revenues be forecast based on the actual net revenues realized in 2009. This period is more reflective of test period market prices than the three year average and, as such, OPG's proposal should be approved.

3.5 HYDROELECTRIC INCENTIVE MECHANISM

Issue 9.2 - Is the hydroelectric incentive mechanism appropriate?

The OEB approved a hydroelectric incentive mechanism for OPG in EB-2007-0905. This mechanism continues to be reasonable because it improves OPG's operational drivers by tying operational decisions to market prices and is advantageous to ratepayers (Ex. E1-T2-S1, page 1).

Under the incentive mechanism, OPG is financially obligated to supply a given quantity of energy ("hourly volume") in all hours and receives the regulated rate for the hourly volume in all hours. If OPG produces more actual energy than the hourly volume in a given hour, it receives regulated payment amounts up to the hourly volume, and market prices for the incremental amount of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated rate is reduced by the production shortfall multiplied by the market price (Ex. E1-T2-S1, page 1).

OPG's decisions to move energy production from off-peak to on-peak periods are, within the constraints imposed by market, asset and hydrological conditions, based on economics. Specifically, these decisions are based on expectations of short run market conditions and the expected price spread between the off-peak and on-peak periods. The deployment of the Pump Generating Station ("PGS"), in conjunction with the SAB Generating Stations, can move substantial quantities of energy from off-peak to on-peak periods. The extent to which the PGS is used to move energy between these periods is largely dependent on the anticipated difference between on-peak and off-peak prices. While there is some peaking capability at R.H. Saunders and the DeCew Falls Generating Stations, the great majority of peaking activity occurs at the Sir Adam Beck complex.

In real time, the cost of pumping in the off-peak periods, including expected market prices for electricity, incremental/decremental gross revenue charges and non-energy load charges, is compared with the forecast value of the additional generation in the next on-peak period(s).

Similarly, during on-peak periods, the value of generation is compared with the net cost of re-filling the PGS reservoir during the next off-peak period(s). In both instances, if the expected value of generation exceeds the expected cost of pumping, then the PGS is bid/offered into the market to operate. This economic assessment does not incorporate any consideration of either the regulated price or the hourly volume.

The use of market signals is important to all market participants (and ultimately ratepayers) as this facilitates the movement of energy from low value periods (typically off-peak) to high value periods (typically on-peak) thus reducing overall demand-weighted market prices and hence customer costs. Absent an incentive mechanism, OPG would rely on the regulated rate for operational decisions. This would result in a flatter production profile and situations where energy that could have been transferred to higher value hours is not (Ex. L-14-037; Tr. Vol. 1, pages 36-37).

OPG estimates that between December 2008 and December 2009, usage of the PGS lowered demand-weighted market prices by approximately $1.14/MWh (Ex. E1-T2-S1, page 2; Tr. Vol. 1, pages 82-83). This value incorporates both the decrease in on-peak prices due to added generation from the PGS and the associated increase in SAB 1 and 2 output, partially offset by an increase in off-peak prices due to additional PGS load and reduced SAB 1 and 2 output.

For the test period, OPG anticipates that the incentive mechanism will result in incremental revenues of $13.3M in 2011 and $16.3M in 2012. These amounts are lower than the revenues earned in 2009, as market price spreads are expected to fall relative to 2009. However, OPG does not forecast a return the circumstances that existed in 2009 - unusually high market spreads and pumping (Ex. E1-T2-S1, page 3; Tr. Vol. 2, page 111).

4.0 NUCLEAR

4.1 NUCLEAR BENCHMARKING AND BUSINESS PLANNING

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

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

4.1.1 Introduction

This section discusses OPG's nuclear benchmarking and gap-based nuclear business planning that is built upon the Phase I and Phase II 2009 Benchmarking reports (individually, the "Phase I Report" and "Phase II Report" and collectively the "Benchmarking Reports") prepared by ScottMadden Management Consultants ("ScottMadden"), which are Exhibits F5-T1-S1 and S2, respectively.

OPG submits that the benchmarking methodology employed by ScottMadden is reasonable and should be accepted by the OEB. Furthermore, the benchmarking results and the targets chosen by OPG (and forming part of its nuclear business plan) are appropriate. By adopting the recommendations of ScottMadden in the Phase II Report, including top-down gap-based business planning, OPG has responded fully to the Benchmarking Reports and the OEB's direction in EB-2007-0905.

4.1.2 Response To The OEB's Benchmarking Direction

In response to the OEB directive in EB-2007-0905 Decision with Reasons (page 37), OPG, in 2009, retained ScottMadden and undertook a rigorous and comprehensive nuclear benchmarking initiative in conjunction with the development of its 2010 - 2014 Nuclear Business Plan.

Benchmarking is an exercise undertaken to evaluate relative performance. The targets reflect the commitment of the organization to meet a given result (Tr. Vol. 3, page 66). OPG undertook this initiative in two phases - evaluation of relative performance against peers and the establishment of appropriate targets - which together forms the basis of the top-down business planning process (Tr. Vol. 3, page 65). Top-down business planning is a new and significant commitment by OPG that establishes limits on cost and expectations for production that directly impact the nuclear payment amounts (Ex. F5-T1-S2, page 1). More specifically, the phases are:

- Phase 1: Benchmark Performance – The goal of this phase was to benchmark Nuclear's operational and financial performance to external peers to determine its relative standing on key operational and financial performance indicators. ScottMadden selected 19 industry performance metrics for this purpose.

- Phase 2: Set Strategic Direction – The goal of this phase was two-fold. First, use the benchmarking results to establish performance improvement targets that will achieve, or significantly drive Nuclear closer to, top quartile industry performance. Second, identify the improvement initiatives best able to close the identified performance gaps to ensure that the desired performance targets are achieved (Ex. F2-T1-S1, page 4).

The Nuclear business unit established strategic direction using the following gap-based business planning process:

- Target Setting: Implementing a “top-down” approach to set operational/financial performance targets and generation targets that will drive OPG closer to top quartile industry performance over the five-year business plan.
- Closing the Gap: By reference to Nuclear’s four cornerstone values of Safety, Reliability, Human Performance and Value for Money, OPG developed various initiatives to close the performance gaps between it and its industry peers over the five-year business plan.
- Resource Planning: Preparing the Nuclear business plan (i.e., the development of cost, staff and investment plans for each site and support group) that is based on the “top-down” targets and incorporates initiatives necessary to achieve targeted results (Ex. F2-T1-S1, page 4).

4.1.3 Benchmarking Phase

The benchmarking exercise undertaken by ScottMadden with the assistance of OPG reflects a rigorous and comprehensive approach. The scope of the study exceeded that filed in EB-2007-0905. All North American nuclear plants were selected as peers, including those using PWR and BWR technology (Ex. F2-T1-S1, page 6).

As ScottMadden noted in the Phase I Report, the benchmarking results present a fair and balanced view of OPG’s operating and financial performance compared to other operators in the nuclear generation industry and that “the results indicate that OPGN performs well across a broad range of industry operational measures, that the Darlington station is within first or second quartile on a majority of measures, but OPG is clearly challenged with respect to reliability and cost at the two Pickering stations” (Ex. F5-T1-S2, page 9). However, programs that have been successful in improving Darlington’s performance are now being implemented at Pickering and positive results are occurring (Tr. Vol. 3, pages 99-100).

In response to the benchmarking results, OPG has taken a prudent and reasonable approach. It has acknowledged that performance gaps exist (Tr. Vol. 3, page 151) and has proactively and deliberately moved forward to put in place measures and processes to close those performance gaps at a pace consistent with continuing safe operation (Tr. Vol. 3, page 176).

4.1.4 Target Setting and Gap-based Planning

The Chief Nuclear Officer ("CNO"), on the recommendation of the OPG's Nuclear Executive Committee ("NEC"), set challenging "top-down" operational and financial performance targets for Nuclear. The top-down targets were set by reference to the Phase 1 benchmarking results. These targets establish performance levels of performance improvement that will achieve or significantly drive OPG Nuclear closer to top quartile industry performance by 2014. (Ex. F2-T1-S1, page 10; Tr. Vol. 3, page 48).

The operational and financial targets established were incorporated into the Nuclear site and support group business planning. As part of that process, the site and support groups along with 16 functional/peer teams were asked to develop improvement initiatives for the 2010 - 2014 Business Plan. The functional/peer teams prepared templates that identified and documented various critical fleet-wide initiatives, whereas the site and support groups focused on site-specific initiatives. The functional/peer teams identified over 150 potential fleet-wide initiatives that were reviewed, revised, tested and prioritized by senior OPG Nuclear managers assisted by ScottMadden. Prioritization was based on the difficulty of the initiative relative to its contribution to achieving the targets. Ultimately 33 fleet-wide initiatives were included in the 2010 - 2014 Business Plan (Ex. F2-T1-S1, page 15).

The combination of the site and support unit initiatives, along with the fleet-wide initiatives, as revised and refined, ensured that the 2010 - 2014 Business Plan operational and financial targets established during the ScottMadden Phase 2 target setting were maintained and/or exceeded. Safe operation, Nuclear's overriding goal, is tracked through a number of metrics including All Injury Rate and Collective Radiation Exposure. Nuclear's primary cost target is total generating cost per MWh (TGC/MWh), which measures the "all-in" costs of production (Ex. F5-T1-S1, pages 13-14). Operational performance metrics include Unit Capability Factor and Forced Loss Rate.

The financial target reductions (compared to the 2009 Business Plan and inclusive of Pickering B Continued Operations) established during Phase 2 target setting totaled $165.1M (Ex. F2-T1-S1, page 16). The financial target reductions from the previous business plan that were ultimately built into the 2010 - 2014 Business Plan totaled $293.0M (inclusive of Pickering B Continued Operations), with the net result that the business plan financial reductions were $128M greater than the Phase 2 financial targets (Ex. F2-T1-S1, page 16).

4.1.5 OPG Has Appropriately Responded to the Recommendations in the Benchmarking Reports

The following is a summary of ScottMadden's key Phase 2 recommendations and OPG's response:

- Benchmarking: ScottMadden recommended that OPG prepare a Nuclear Benchmarking Report in 2010 using the process and procedures developed by the joint ScottMadden/OPG team in Phase 1. OPG accepted this recommendation (Ex. L-14-014). The 2010 Benchmarking Report was filed as J3.5.
- Target Setting: ScottMadden recommended that OPG Nuclear engage in a top-down target setting process similar to that undertaken in 2009 when it revisits its operational and financial performance targets as part of business planning. OPG Nuclear accepted this recommendation and is committed to using top-down target setting in its business plans (Ex. F2-T1-S1, page 12; L-14-015).
- Fleet-wide Improvement Initiatives: ScottMadden encouraged OPG Nuclear to refine and improve on the peer team initiatives and to make improvements to peer teams to improve their ability to identify and drive changes. ScottMadden also recommended re-examination of the current peer team's structure and governance. OPG Nuclear accepted this recommendation and, has taken steps to improve peer team effectiveness (Tr. Vol. 3, pages 163-164).
- Site and Support Unit Business Plans: ScottMadden recommended that OPG Nuclear adopt its gap-based business planning model. OPG Nuclear accepted this recommendation, and has implemented a gap-based business planning process in its preparation for the 2011 - 2015 Business Plan (Ex. L-14-017).
- Plan Execution and Monitoring: ScottMadden recommended that OPG Nuclear establish a dedicated organization structure to oversee and coordinate the high impact/high hurdle

improvement initiatives identified during the planning process, such organization to be headed by its own senior executive. ScottMadden has also recommended the use of external third parties to assist OPG Nuclear in implementation. OPG Nuclear accepted this recommendation and has assembled a project management team to drive the implementation of a number of the key initiatives and to provide general oversight over all of the projects designed to deliver significant improvements in all cornerstone areas. The project management team has been up and running since January 2010. (Ex. F2-T1-S1, page 12) OPG has revised its governance structure to ensure all levels of leadership are engaged in the improvement process. A director, accountable to the Nuclear Executive Committee and the CNO, has been appointed to ensure peer team performance (Ex. L-14-016, page 1). OPG also retained ScottMadden to assist in implementation (Ex. L-1-062).

As the forgoing material demonstrates, OPG has responded appropriately to the recommendations in the Benchmarking Reports and the OEB's benchmarking direction set out in EB-2007-0905. In fact, OPG has exceeded the scope of benchmarking discussed in that proceeding and has established an ongoing top-down process of benchmarking and target setting that will allow OPG Nuclear to close performance gaps through continuous improvement and re-evaluation while at the same time staying true to its four cornerstones of safety, reliability, value for money and human performance. As such, the benchmarking undertaken and the business planning targets established in this proceeding are reasonable and should be accepted by the OEB.

4.2 NUCLEAR OM&A, FUEL, PICKERING B CONTINUED OPERATIONS AND NUCLEAR NON-ENERGY REVENUES

Issue 6.3 - Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Issue 6.6 - Is the forecast of nuclear fuel costs appropriate?

Issue 6.7 - Are the proposed expenditures related to continued operations at Pickering B appropriate?

Issue 7.2 - Are the proposed test period Nuclear business non-energy revenues appropriate?

4.2.1 Introduction

This section presents OPG's forecast Nuclear OM&A and fuels forecasts, which constitute the Nuclear expenses necessarily to safely, reliably and efficiently operate and maintain OPG's nuclear stations in the test period. It also addresses Pickering B Continued Operations and nuclear non-energy revenues. The specific subjects covered are:

- Base OM&A
- Project OM&A
- Outage OM&A
- Fuels
- Pickering B Continued Operations
- Nuclear non-energy revenues

OPG's forecast Nuclear OM&A and fuel spending in millions is as follows (Ex. F2-T2-S1, page 1; Ex. F2-T3-S1, page 1; Ex. F2-T4-S1, page 1; Ex. F2-T5-S1, page 1):

	2011	**2012**
Base OM&A	$1,192.3	$1,219.8
Project OM&A	$135.9	$132.2
Outage OM&A	$214.8	$201.1
Fuel	$235.6	$261.7
Total	**$1,778.60**	**$1,814.80**

The forecast Nuclear expenses and declining spending trends discussed in this section are the product of the target setting and cost control initiatives discussed in the Benchmarking and Business Planning section. The total generating cost/MWh benchmarking measure includes all of these costs as well as capital costs and corporate allocations and centrally-held costs.

4.2.2 Base OM&A

Base OM&A provides the main source of funding for operating and maintaining the nuclear facilities to ensure they operate safely, meet all applicable regulatory standards, achieve targeted levels of production, and maintain and improve their reliability. Base OM&A also funds regular labour for planned outages, the cost of all forced outages and de-rates and the indirect costs of commercial activities such as the provision of inspection and maintenance services to OPG facilities and external customers.

Base OM&A funds the staff that operate OPG's nuclear facilities on a 24-hour basis including starting up and shutting down systems and the plant itself. Base OM&A funding is necessary to ensure the safety of stations operations and respond to any emergencies that arise. The CNSC approves the structure of OPG's operations organization, including mandating minimum shift complement to address foreseeable emergency response requirements.

Base OM&A is forecast at $1,192.3M and $1,219.8M in 2011 and 2012, respectively. In the period since the last payment amounts application, OPG has made significant strides in controlling the costs and improving operation of its nuclear facilities and developed its forecasts on the expectation of continuing improvement during the test period (Ex. F2-T2-S1, page 1). A comparison between actual 2008 base OM&A and forecast 2012 base OM&A shows a decline of more than $32M (Ex. F2-T2-S1,Table 1). Since 2008, OPG has used base OM&A spending to reduce its elective and corrective maintenance backlogs and forecasts additional significant improvements over the test period.

The results OPG has achieved to date and its commitment to further savings out to 2014 demonstrate that the company has embraced the culture of cost control. OPG's test period Base OM&A forecast reflects this fact and should be approved.

4.2.3 Project OM&A

Project OM&A funds are expended on activities that meet the criteria for categorization as a project, but do not meet the criteria for capitalization (Ex. F2-T3-S1, page 1). OPG seeks approval of forecast project OM&A expenses of $135.9M and $132.2M in 2011 and 2012 respectively. These amounts include the project OM&A component of Pickering B Continued Operations and the Fuel Channel Life Cycle Management Project discussed in Section 4.2.6.

OPG's process for managing OM&A projects is identical to that described in Section 4.3 below for capital projects.

No contingency amounts are included in the project OM&A budget or the test period revenue requirement request (Tr. Vol. 5, pages 158, 160). While contingency amounts are indentified in the Business Case Summaries for individual projects to support the selection of the best alternative, they are not included in the budgets available to project managers. Should use of a contingency become necessary, appropriate approval is requested and if granted, the necessary contingency is sourced from elsewhere in overall project OM&A budget (Tr. Vol. 5, pages 157-159). In this way, OPG can address issues requiring the use of contingency funds without exceeding its targeted level of project OM&A spending.

OPG's test period forecast reflects a reduction in spending on portfolio project OM&A (i.e., not including non-portfolio projects like Pickering B Continued Operations or Fuel Channel Life Cycle Management) from about $120M a year in the previous test period to about $110M per year in this application (Ex. F2-T3-S1, Table 1). In addition, as explained in Ex. D2-T1-S1, page 4, the test period project OM&A forecast now includes the costs of "SAVH" (sickness, accident, vacation and holidays), about $6M to $7M per year, which had been included in base OM&A in the previous application. As a result, the actual reduction in project portfolio OM&A from the last test period is more than $16M per year. This reduced level of portfolio OM&A has been achieved through increased focus on cost control, but has also required some reprioritization of project work (Ex. D2-T1-S1, page 3).

More detail on OPG's project prioritization and approval process and the improvements it has made in managing its project portfolio are provided in Section 4.3 below. The evidence in this proceeding clearly demonstrates that OPG has a robust and well managed process for selecting and executing projects, and has implemented significant cost control measures to limit the size of its overall project OM&A expenditures. Based on this evidence, OPG's project OM&A budget is reasonable and should be approved.

4.2.4 Outage OM&A

Outage OM&A includes the expenditures on the incremental labour (e.g., overtime, temporary staff and external contractors), services and materials necessary to complete OPG's planned outages (Ex. F2-T4-S1, pages 1-3). OPG forecasts outage OM&A spending of $214.8M and $201.1M in 2011 and 2012, respectively.

Forecast outage OM&A expenditures depend on the number of outages undertaken each year and the particular tasks to be accomplished in each outage (a combination of "routine" inspection and maintenance and “non-routine” work specific to a particular outage) (Ex. E2-T1-S1, page 6). Thus a year-over-year comparison of outage OM&A expenditures to develop a trend is not a meaningful exercise because the yearly expenditures vary with the number and specifics of each year’s outages (Tr. Vol. 6, pages 46-47). The approved outage OM&A budget for each of the test years is directly tied to the five-year Integrated Plan, which establishes OPG’s generation plan and outage schedule. The costs of each outage are based on the specific plan for each outage, which details the tasks to be completed and the expected duration (see example in Ex. E2-T1-S1, Attachment 3).

The level of forecast outage OM&A spending over 2011 - 2012 is significantly less than the 2009 - 2010 spending level primarily because of the completion of the vacuum building outages at Darlington and Pickering in 2009 and 2010, respectively and the fact that Darlington had two outages in 2010, compared to one outage in each of 2011 and 2012. Also, as described above, OPG has undertaken an Outage Improvement Strategy initiative intended to further improve the company’s ability to plan and execute outages, which will lower their costs and shorten their duration.

The forecast level of test period outage OM&A spending reflects the impacts of Pickering B Continued Operations, which will increase the scope and duration of Pickering B test period outages and thus outage OM&A costs.

OPG’s forecast Outage OM&A spending is necessary to properly inspect and maintain the prescribed nuclear facilities and should be approved.

4.2.5 Nuclear Fuel

OPG’s forecast test period fuel costs are $235.6M and $261.7M for 2011 and 2012, respectively. OPG requires a secure supply of high quality fuel to ensure the continued operation of its reactors. OPG’s goal is to obtain the necessary fuel at the lowest cost consistent with obtaining a secure supply of high quality fuel (Ex. F2-T5-S1, page 1). OPG has entered into supply contracts with a five traditional, long-term suppliers with proven track records of performance thereby reducing supply risk by transacting with a diverse group of high quality suppliers (J4.11, Attachment 2, page 7).

OPG's nuclear fuel supply chain has three components: 1) the purchase of uranium concentrate, 2) fuel conversion services that convert uranium concentrate into uranium dioxide, and 3) fuel bundle manufacturing services that take the uranium dioxide and use it to manufacture the specific fuel bundle configuration required by each of OPG's stations. The conversion and fuel bundle manufacturing processes are tightly controlled to ensure high quality products. The failure of a nuclear fuel bundle can have significant implications on nuclear production including the potential for reactor shutdown and increased radiological risk (Ex. F2-T5-S1, page 4).

In order to determine the company's needs at each stage of the nuclear fuel supply chain, OPG begins with a forecast of the fuel bundles required to meet the company's forecasted production (Ex. F2-T5-S1, page 3). OPG maintains an inventory of fuel bundles equal to 12 months of anticipated consumption to account for potential supply disruptions. To support the continued production of fuel bundles, OPG maintains inventories of both uranium dioxide and uranium concentrate.

OPG purchases fuel bundle manufacturing services under a contract with a qualified domestic manufacturer. OPG performs surveillance on the manufacturing processes to ensure compliance with Canadian quality control standards. Owing to its ongoing commitment to sourcing high quality fuel bundles, OPG has not had a manufacturing-related fuel bundle defect in over 16 years (Ex. F2-T5-S1, page 4). OPG purchases uranium conversion services from a qualified domestic supplier under a contract that requires the supplier to maintain an inventory of certified uranium dioxide for OPG's use in the event of a supply disruption. Pricing for both fuel conversion and fuel bundle manufacturing is volume dependent and indexed.

Uranium concentrate is obtained via long-term contracts and the spot market. The price of uranium is determined on a worldwide market and is subject to substantial fluctuations that are beyond OPG's control (Tr. Vol. 5, page 111). OPG uses a variety of approaches to address price volatility (TR Vol. 4, pages 111-113). OPG enters into long-term indexed contracts, which include a base price set at the time of contract signing, and a formula or inflation related index, which escalates the price to the time of delivery. OPG also enters into long-term market-related pricing contracts, where the price is based on the market price at the time of delivery.

Currently, OPG's contract mix is about 25 per cent indexed and 75 per cent market-related (Tr. Vol. 4, page 111).

Spot market purchases are undertaken when market fundamentals suggest an opportunity, but are limited by the size of the market and the availability of suitable counterparties (Tr. Vol. 5, page 78). OPG continually reassess its fuel needs against its current inventory and market conditions to determine the appropriate procurement activities (J4.11 and attachments).

OPG employs the same fuel procurement strategy that the OEB found reasonable in EB-2007-0905. No new circumstance has arisen that would cause OPG to deviate from that strategy. Benchmarking results based on EUCG data indicate that the three-year fuel cost per MWh for OPG's plants are lower than any other plant in the comparator group, which includes Bruce Power (Ex. F5-T1-S1, pages 133 and 156).

OPG's fuel procurement strategy is undertaken by experienced professionals and reviewed by its senior management as part of the business planning process (Tr. Vol. 14, page 60). The strategy is reviewed internally on a yearly basis (J4.11). In addition, the company has had its fuel procurement strategy reviewed by external experts, Ux Consulting Company, prior to its first payment amounts application. This review validated OPG's approach to fuel contracting and made certain specific recommendations, which OPG has responded to appropriately (J4.11). OPG has also evaluated various approaches to contract renegotiation should an existing contract become unfavorable relative to market conditions (J4.11).

OPG's nuclear fuel procurement strategy recognizes the critical need to ensure that the company has adequate supplies of nuclear fuel at all times. Failure to secure sufficient fuel supplies would put OPG at risk of having to attempt to purchase fuel in a volatile and illiquid spot market or idle its reactors. Neither of these risks is acceptable to the company and, OPG submits, to the people of Ontario who depend on a reliable supply of baseload generation. Furthermore, the fuel OPG that procures must meet the highest quality standards to ensure that it does not compromise safety and ongoing operations. In these circumstances, the balance that OPG has struck in its fuel procurement strategy, which includes an appropriate mix of indexed and market-related contracts, should be respected and its forecast of nuclear fuel expense approved.

4.2.6 Pickering B Continued Operations

Continued Operations is a program to increase the output of the four Pickering B units by extending their operating lives by four calendar years (Ex. F2-T2-S3, page 4). This extension would move the planned shutdown of the Pickering B units from the currently anticipated dates of 2014 - 2016 to 2018 - 2020. This additional operating life would be achieved by incremental maintenance, inspections and analyses. This project is covered by O. Reg.53/05 section 6(2)4 because it will increase Pickering's output by allowing it to operate for a longer period (Tr. Vol. 15, page 50).

To support continued operations, OPG proposes to undertake the following activities in the bridge year and test period:

- additional maintenance to improve the plant's material condition and ensure the continued fitness-for-service of the plant's major components over the additional operating period,
- increased inspections,
- increased Spacer Location and Relocation work,
- selective feeder replacement, and
- Fuel Channel Life Cycle Management project, an OPG-initiated project undertaken as a CANDU Owners Group joint-funded program, to increase the certainty about the remaining service lives of CANDU units (Ex. F2-T2-S3, page 6).

The test period costs for continued operations are $92.9M, which includes $8.8M related to the Fuel Channel Life Cycle Management project (Tr. Vol. 5, pages 92-93). These costs are all OM&A (Ex. F2-T2-S3, page 1). In addition, the incremental outage days associated with Pickering B Continued Operations reduce test period nuclear production by 1.9 TWh. This reduction is included in OPG's production forecast (Ex. E2-T1-S1, page 12).

Achieving continued operations will produce a number of benefits. It will increase the forecasted net output of Pickering B by 61.9 TWh as a result of the station operating for four more years (Ex. F2-T2-S3, Attachment 1, page 17). This output figure is "net" because it includes both the additional production from extending the station's operating life and the decrease in production from the additional outage days necessary to achieve continued operations. In addition, continuing to operate Pickering B will allow Pickering A to operate to

2020 and produce an additional 43.1 TWh (*Id*). This incremental production at Pickering A is properly assigned as a benefit of Pickering B Continued Operations because OPG has concluded that the significant technical and economic challenges associated with operating Pickering A without at least two operating units at Pickering B would likely require Pickering A to shutdown when the third unit at Pickering B shuts down (Ex. F2-T2-S3, pages 5-6; Tr. Vol. 4, page 44).

OPG estimates that Pickering B Continued Operations has a net present value of $1.1B (2010 dollars). This figure is based on the difference between the estimated cost of Pickering B's output and the estimated cost of replacement generation. It also includes the value of the additional production from Pickering A that is made possible by continuing to operate Pickering B, which represents some $420M of the total projected net present value (Ex. F2-T2-S3, Attachment 1, page 1). Additional benefits include the deferral of transmission upgrades that will be necessitated by the closure of Pickering A and B and the increased availability of nuclear base load generation from Pickering during the first part of the Darlington refurbishment (Tr. Vol. 4, pages 45-46). OPG has conducted sensitivity analyses, which demonstrate that the anticipated benefits of continued operations are relatively insensitive to the costs of the project (Ex. F2-T2-S3, Attachment 1, page 9).

The decision to embark on Pickering B Continued Operations was undertaken in the context of evaluating the potential for refurbishing Pickering B. Ultimately, OPG determined to pursue continued operations rather than refurbishment because of:

- the economics of the Pickering B refurbishment,
- the required lead time to procure steam generators and the resulting overlap with other refurbishments,
- the availability of resources to manage multiple refurbishments in the province,
- the potential economic benefit of the continued operations of Pickering B, and
- the need to manage the overall availability of OPG's nuclear fleet (Ex. F2-T2-S3, page 4).

While OPG expects that its ongoing efforts ultimately will confirm the feasibility of continued operations, given the current stage of its investigation, the company has assigned a medium level of confidence to achieving the expected additional life at Pickering B (Tr. Vol. 4, page

117). Given this level of confidence, OPG is not in a position to capitalize those project expenditures that might otherwise meet its capitalization rules.[1] OPG's Depreciation Review Committee ("DRC") determined that the medium level of confidence was not an adequate basis for adjusting the Pickering B's end of life for depreciation purposes (Ex. L-2-025). That said, OPG also believes that there is a good probability that it will achieve 240,000 full-power hours (equivalent to four years of additional operation) or it would not embark on the project (Tr. Vol. 4, page 205).

As set out in the DRC Report (Ex. F4-T1-S1, Attachment 1, page 5), for financial accounting purposes, making changes to existing station end-of-life dates and asset class service lives requires a high degree of confidence about a new estimate (Tr. Vol. 10, pages 72-73, 75; Ex. L-2-025). In the case of Pickering B Continued Operations, successful completion of a work program including physical work in the plant, laboratory tests, analytical work and discussions with the nuclear safety regulator is the key to achieving high confidence in the successful implementation of continued operations.

By way of comparison, OPG has, for financial accounting purposes, achieved high confidence for the Darlington Refurbishment project. The high confidence is based in large part upon OPG's detailed assessment of the project's cost and scope during the initiation phase.

Based on its analyses to date, OPG believes that its expenditures on Pickering B Continued Operations are prudent and should continue. The Minister of Energy and the OPA have both concurred with OPG's decision to undertake continued operations (Ex. D2-T2-S1, Attachment 3 and Ex. F2-T2-S3, Attachment 2). For these reasons, the OEB should approve OPG's proposed expenditures on Pickering B Continued Operations.

4.2.7 Non-energy Revenues

OPG proposes that revenues (less costs) from the following non-energy related businesses be applied as an offset to the Nuclear revenue requirement:

- Heavy water services
- Isotope sales (cobalt 60; tritium)

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[1] The majority of OPG's Pickering B Continued Operations expenditures are for maintenance activities that would not be eligible for capitalization in any event (Tr. Vol. 5, page 98).

- Inspection and maintenance services

The forecast of Nuclear non-energy revenues (less costs) for the test period is $29.0M and $20.9M in 2011 and 2012, respectively (Ex. G2-T1-S1, Table 1). OPG also earns a relatively small amount of revenues from the nuclear units' provision of ancillary services. These services are discussed with hydroelectric ancillary services.

OPG forecasts a declining trend in non-energy revenues compared to the previous test period (Ex. G2-T1-S2, Table 1). This decline is primarily attributable to the company's decision to end the external provision of IMS services (Ex. G2-T1-S1, page 7) and the proposal to retain the revenues from surplus heavy water sales, both of which are both discussed below. OPG's forecast of Nuclear non-energy revenues is appropriate and should be adopted.

Plans to End the Provision of IMS Services to External Parties

IMS supports OPG's internal work program needs for fuel channel, steam generator, and balance of plant inspections and specialized maintenance at Pickering A, Pickering B, and Darlington. Costs associated with the provision of IMS work activities for all OPG facilities fall under Base and Outage OM&A.

IMS's primary external customer is Bruce Power. In conjunction with the Bruce Lease, IMS entered into agreements with Bruce Power for the provision of inspection and maintenance services on a commercial basis. These agreements are subject to unilateral termination with notice and OPG and Bruce Power have agreed to terminate them effective June 2011. OPG and Bruce Power are continuing to work together to ensure an orderly transition. OPG anticipates providing inspection and maintenance services and termination assistance to Bruce Power through the first half of 2011 (Ex. G2-T1-S1, pages 7-8).

OPG Proposes to Retain Revenues from the Sale of Surplus Heavy Water

OPG seeks opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG's current and future needs. As of December 2010, the amount of heavy water held in inventory that is surplus to OPG's current and future needs is forecast to be 537 tonnes. (Ex. G2-T1-S1, page 3, Chart 2).

The sale of these surplus heavy water assets will not impact the provision of OPG's regulated services to ratepayers as OPG has conservatively set aside sufficient quantities of heavy water to serve the future needs of OPG, including its contractual obligations to Bruce Power (Ex. G2-T1-S1, page 4). The administration and sale of the surplus heavy water assets requires minimal business support. OPG has identified the direct and other support costs associated with the sale of the surplus heavy water and these have been removed from the Nuclear revenue requirement (Ex. L-14-027).

OPG proposes to exclude any revenues (and costs) associated with the future disposition of surplus heavy water assets from nuclear non-energy revenues, effective March 1, 2011. Surplus heavy water assets are the property of OPG and its shareholder. These assets are not, and never have been, included in the prescribed facility rate base, are not required for the provision of regulated services and do not rely on the prescribed facilities for their production or management (Ex. G2-T1-S1, page 4; J10.6; Ex. L-1-125). OPG earns no regulated rate of return on these assets. Moreover, there is no requirement under O. Reg. 53/05 to use the revenues from these non-regulated surplus heavy water assets as an offset to the Nuclear revenue requirement. Based on these facts, OPG submits that it should be permitted to retain the revenues from surplus heavy water sales.

4.3 NUCLEAR CAPITAL PROJECTS

Issue 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?

Issue 4.5 - Are the capital budgets and/or financial commitments for 2011 and 2012 for the Nuclear business appropriate and supported by business cases?

Issue 4.6 - Are the proposed in-service additions for nuclear projects appropriate?

Issue 4.7 - Is the proposed treatment for the Pickering Units 2 and 3 isolation project costs appropriate?

4.3.1 Introduction

This section presents the Nuclear operations capital budget for the test period. It also provides an overview of the nuclear project management processes that covers both the capital projects discussed in this section and the OM&A projects discussed previously. In-service additions and the treatment of Pickering Units 2/3 isolation costs also are discussed.

4.3.2 Nuclear Capital Spending

OPG's Nuclear operations capital expenditures are $191.7M and $191.5M in 2011 and 2012, respectively. This amount consists of project portfolio capital expenditures ($172M in each of 2011 and 2012) and minor fixed assets ($19.7M and $19.5M in 2011 and 2012 respectively) (Ex. D2-T1-S1, page 5, Chart 2). Planned capital expenditures for Darlington Refurbishment are not included in these figures. Discussion of Darlington Refurbishment and the status of New Nuclear at Darlington are presented in Section 4.5 below.

The annual totals for project capital and OM&A project expenditures in the nuclear project portfolio are consistent with OPG's target annual re-investment levels of $25M to $30M per nuclear unit (for multi-unit stations) (Ex. D2-T1-S1, page 3). These target portfolio budget levels were developed in consideration of: historical investment patterns; project execution capabilities; the potential beneficial impact of the improved project portfolio management processes; and high level comparative data from other nuclear utilities. The validity of this approach is supported by the stable cost performance over the period 2008 - 2012 (Ex. D2-T1-S1, page 4, Chart 1). OPG's cost control and prioritization efforts have allowed OPG to hold nuclear project portfolio capital spending at 2010 levels for both test years despite labour and material cost escalation.

In addition to the expenditures covered by the nuclear project portfolio, there are other test period nuclear operations project expenditures that are managed and approved outside of the portfolio: the purchase of minor fixed assets (capitalized in accordance with OPG's capitalization policy), as well as non-portfolio OM&A project expenditures (i.e., test period project costs associated with Pickering B Continued Operations, and Fuel Channel Life Cycle Management projects).

OPG's Approach to Developing and Managing the Project Portfolio Ensures Appropriate Project Prioritization and Oversight

Nuclear employs a portfolio approach to assess all nuclear operations projects (OM&A and capital) in the same manner (Ex. D2-T1-S1, page 2). Consistent with OPG's corporate policy, a project is defined as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program.[2] The final decision on whether work will be classified as a project is made by the Nuclear Asset Investment Screening Committee ("AISC") having regard to the complexity and materiality of the work, and the following criteria:

- Whether the incremental cost is greater than $200k per generating unit.
- Whether the execution duration is limited, with defined start and finish dates.
- Whether the work is clearly incremental to regular ongoing work, non-repetitive in nature, recurring at a frequency of less than once every six years.
- Whether sponsorship and management accountabilities can be clearly defined.

OPG nuclear projects are developed to meet regulatory commitments (e.g., from the CNSC), decrease future base or outage OM&A expenditures, increase system or unit reliability, address system obsolescence or increase the output of the station (Ex. D2-T1-S1, page 2). Among other things, the nuclear project portfolio facilitates comparative value assessments for project prioritization, and also forms the basis for project budgeting during the business planning process.

For business planning purposes, it is useful to characterize forecast project portfolio costs so as to identify the degree of budget commitment in future years. There is a high level of budget commitment for work that has been released by a BCS approval; a lesser degree for the balance of the project budget that is yet to be released and that's associated with developmental or partial project releases (due to the fact that such projects may not proceed to execution phase, or the project estimate may change); and, and a still lesser degree of commitment to the large number of projects that are under consideration for potential inclusion in the project portfolio as "listed work to be released". Projects in this third category are undertaken based on the priority assigned to them after thorough review by the AISC. Overall, OPG is committed to completing necessary work up to the total level of the project portfolio.

The nuclear project portfolio is approved via the OPG business planning process with the OPG Board of Directors approving the OM&A and capital projects portfolio budget which is then administered via the portfolio management process described below.

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[2] OM&A projects are those activities that meet the definition of a project, but do not meet OPG's capitalization criteria.

The five project life cycle phases and the associated “release” normally accompanying each phase are outlined in OPG’s evidence (Ex. D2-T1-S1, pages 5-6). A project’s progression between the five phases is governed by a management process, which ensures that a periodic, systematic review is conducted and that approvals are obtained before proceeding with further investment. The AISC plays a key role in assessing value at these decision points. As a result, all projects that are allowed to proceed to implementation have demonstrated value in terms of improving OPG’s operations and/or lowering its costs.

OPG has undertaken a significant number of initiatives to continue to improve the performance of the project management function, to continually improve cost performance versus budget, and to increase value received for money spent. Based on industry best practices, rigorous planning and project evaluation processes have been implemented. These processes, at the front end of the project life cycle, focus on value engineering, project scoping and scheduling, and a disciplined approach to cost estimating and management of project risk (Ex D2-T1-S1, page 12; Tr. Vol. 5, page 168).

In addition, project staff are encouraged to identify value improvement opportunities. As a result, cost savings, cost avoidance, and process and technology efficiency improvements have increased significantly since 2009 (Ex. D2-T1-S1, page 13). The cumulative benefits of the above initiatives are more realistic and achievable project plans and improved cost and schedule performance, as demonstrated in the assessments of completed projects as shown in Ex. D2-T1-S2, Section 3.2 and Ex. F2-T3-S3, Section 3.2.

OPG submits that the level of proposed capital expenditure is appropriate, and that the company properly scopes, prioritizes and executes projects. On this basis, the OEB should find that the proposed nuclear capital budgets are appropriate.

4.3.3 Nuclear In-Service Additions

OPG’s forecast test period nuclear in-service additions of $175.5M and $187.6M for 2011 and 2012 respectively should be approved by the OEB. In accordance with the OEB filing guidelines, OPG filed detailed business case summaries for all in-service projects for the test years for projects with total project costs greater than $10M (except for security classified projects) (Ex. D2-T1-S2, Table 1b) ($83.4 and $107.6M for 2011 and 2012 respectively). Also in accordance with the filing guidelines, projects with total project costs between $5-$10M and contributing to in-service additions in the test years were summarized at Ex. D2-T1-S2, Table 2a and 2b ($9.1 and $0.6M for 2011 and 2012 respectively), while projects with total costs less $5M were aggregated at Ex. D2-T1-S2, Table 3 ($12.8 and 10.8M for 2011 and 2012 respectively). The remaining amount for in-service additions in the test years is composed of minor fixed assets and supplemental in-service amounts (Ex. D2-T1-S2, page 4 and Table 4c).

Pickering Units 2/3 Isolation Costs

In the EB-2007-0905 Decision, page 35, the OEB directed OPG to provide a more detailed analysis of the treatment of Pickering 2/3 Isolation project costs, including an explanation of why certain costs are capitalized. The following discussion summarizes why OPG's treatment of these costs is appropriate (Ex. D2-T1-S1, pages 18-20).

In order for work to be eligible for funding as decommissioning, OPG must demonstrate to the Province that this work is driven exclusively by decommissioning needs and receive provincial approval. This requirement is set out in the Ontario Nuclear Funds Agreement ("ONFA"). In the case of the P2/P3 Isolation project, OPG was unable to pass the ONFA eligibility test because the project's primary purpose is to allow Pickering A Units 1 and 4 to continue operating, not the decommissioning of Units 2 and 3. As a result, the cost of the P2/P3 Isolation project had to be funded by OPG and OPG used its standard accounting policies for categorizing spending as capital or OM&A to determine the appropriate treatment for these costs. In contrast, OPG did satisfy ONFA's eligibility test with respect to costs associated with the safe storage of Pickering A Units 2 and 3 and was thus eligible to recover these costs from the decommissioning fund.

OPG undertook a detailed breakdown of the work required under the Pickering 2/3 Isolation project. A detailed accounting review of all project activities was then undertaken by OPG in October 2005, to identify the specific driver and the consequent accounting classification of each work activity. The accounting analysis applied OPG's capitalization policy to determine which project costs should be capitalized and which would default to project OM&A. This accounting analysis and OPG's resulting conclusions in terms of capitalization have been reviewed and approved by OPG's external auditors in every year since 2005.

4.4 NUCLEAR PRODUCTION FORECAST

Issue 5.2 - Is the proposed nuclear production forecast appropriate?

OPG is seeking approval of nuclear production forecast of 48.9 TWh and 50 TWh for 2011 and 2012, respectively (Ex. E2-T1-S1, Table 1). This section discusses the derivation of OPG's forecast and recent trends in production. Outage OM&A is discussed above as part of the discussion of Nuclear OM&A.

4.4.1 OPG Produces Detailed Forecasts of Nuclear Production

OPG's Nuclear production planning process establishes annual production forecasts for its individual nuclear units, an aggregated forecast for each station and an overall corporate forecast. Nuclear facilities are designed to operate continuously at full power as base load generators. Therefore, the annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages, forced production losses (i.e., unplanned outages and derates). As such, the production planning process is focused on establishing annual planned outage schedules and on estimating forced production losses.

All generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or a derating of the generating unit. Accordingly, OPG develops forced loss rate ("FLR") targets that reflect the risk of such forced production losses for all units in the station. Forced loss rate targets are based on the plants' recent performance, any known improvements or deterioration in plant material condition, past and future investment in reducing corrective and elective maintenance backlogs to improve reliability, other performance improvement initiatives, as well as known risks.

The nuclear production planning process generates an annual Integrated Plan, with the following elements:

- A five-year planned outage schedule for all stations that includes unit outage start dates, end dates, and durations.
- A summary of major elements comprising the scope of work that will be executed during each outage, with a higher level of specificity for outages during the first two years of the Integrated Plan.

- Operational reliability performance targets such as unit capability factor and the anticipated level of FLR.
- Outage resource requirements and cost estimates for inclusion in the outage OM&A budget.
- Five-year generation forecasts in terawatt-hours for individual nuclear units and an aggregated forecast for each station.

The Integrated Plan is finalized after a CNO review. The final Integrated Plan is incorporated into OPG's overall business planning process.

4.4.2 OPG's Proposed Allowance for Major Unforeseen Events More Accurately Captures Production Risks in the Forecast

OPG's best estimate of test period nuclear production is contained in OPG's 2010 - 2014 Business Plan, approved by its Board of Directors and endorsed by OPG's shareholder. This estimate includes a 2.0 TWh per year allowance for major unforeseen events (J10.1, page 5). This business plan forms the basis of OPG's payment amounts application. On average from 2005 - 2008, OPG's actual annual nuclear production has been less than the approved nuclear business plan forecast by approximately 3.5 TWh. An analysis of these production shortfalls revealed that on average more than 2 TWh per year in lost production was the result of major unforeseen events that lead to forced outages and forced extensions to planned outages (Ex. E2-T1-S1, Attachment 4). Accordingly, OPG has incorporated a 2.0 TWh adjustment to account for these events and produce a more accurate forecast of nuclear production.

Major unforeseen events are defined as a major forced outage or Forced Extension to a Planned Outage ("FEPO") with an impact of more than 0.25 TWh on generation and that were unforeseen and not incorporated into life cycle management plan, not addressed through asset management planning, resulted from unanticipated CNSC regulatory change or a force majeure event (Tr. Vol. 6, page 75). As the events are unforeseen, they cannot be allocated to a specific station on a forecast basis (Tr. Vol. 6, page 108). As a result, the stretch targets contained in the Nuclear Business Plan, which are used to incent and challenge the Nuclear organization, do not include an adjustment for major unforeseen events (Ex. E2-T1-S1, page 11).

As a result of the rigour and thoroughness of OPG's Integrated Plan described above and its analysis relating to major unforeseen events, the nuclear production forecast that underpins OPG's business plan is the most accurate forecast of test period nuclear production and should be approved.

4.4.3 OPG Forecasts Increased Nuclear Production During the Test Period

OPG's test period nuclear production forecast represents a significant increase over the actual production achieved during 2008 - 2009. The trend in nuclear production starting from 2007 was a production decline over the period 2008 - 2010 followed by an anticipated increase in 2011 and a further increase in 2012 (Ex. E2-T1-S1, Table 1). The major factors influencing the trend in production over 2007 - 2012 are:

- An expectation of improved performance at the Pickering units.
- A vacuum building outage at Darlington in 2009 that required all four Darlington units to be shut down for approximately four weeks.
- A vacuum building outage at Pickering in 2010 that required all four Pickering B units and the two Pickering A units to be shut down for approximately four weeks.
- The extended scope and duration of planned outages at Pickering B over the period 2010 - 2012 as a result of the Pickering B Continued Operations initiative. There are 167 additional planned outage days in the test period for Continued Operations corresponding to a reduction of 1.9 TWh in the production forecast for the test period.
- An improvement in the forecast FLR at Pickering A starting in late 2009 reflecting the elimination of the three per cent derate that was imposed in 2007.

The nuclear production forecast for the 2011 - 2012 period does not include a specific provision for reduced production due to SBG. OPG was not subject to material reductions in nuclear generation due to SBG in 2008 or 2009 and does not anticipate material impacts during the test period.

4.5 DARLINGTON REFURBISHMENT AND NEW NUCLEAR AT DARLINGTON

> **Issue 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?

> **Issue 4.5** – Are the capital budgets and/or financial commitments for 2011 and 2012 for the Nuclear business appropriate and supported by business cases?

> **Issue 6.3** – Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

4.5.1 Introduction

This section discusses OPG's actions and associated costs to refurbish the Darlington nuclear station and its activities related to new nuclear development at Darlington. OPG plans to refurbish the existing four units at Darlington and operate them until approximately 2051. This project is covered by O. Reg. 53/05 Section 6(2)4 because it will both refurbish the Darlington station and increase its output by allowing it to operate for a longer period.

This project has been approved by OPG's Board of Directors and endorsed by the Province via a letter from the Minister of Energy that states:

> The government is satisfied that the detailed technical, regulatory and risk analyses performed by OPG resulted in the optimal decisions regarding refurbishment and future operation of the Darlington and Pickering B units respectively and concurs with the November 19, 2009 decision by the OPG Board of Directors. (Ex. D2-T2-S1, Attachment 3.)

The Ontario Power Authority also endorsed OPG's decision (Ex. F2-T2-S3, Attachment 2.). The decision to proceed with the Darlington refurbishment has a number of revenue requirement consequences discussed below.

OPG's test period revenue requirement does not include any capital or non-capital costs related to new nuclear development. Any costs OPG incurs related to the planning and preparation for new nuclear will be recovered from a new funding mechanism determined by the Province for new nuclear. 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.

4.5.2 OPG Seeks The Following Approvals With Respect To Darlington Refurbishment

While OPG is not seeking OEB approval of the decision to refurbish Darlington, it is seeking the following approvals associated with the project:

- Approval of test period OM&A costs (which form part of the Nuclear revenue requirement) of $5.9M and $4.5M in 2011 and 2012, respectively, for definition phase work for the Darlington Refurbishment project as presented in Ex. F2-T7-S1, Table 1.
- Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from the impacts of the service life extension, for purposes of calculating depreciation, and the change in the Nuclear liabilities associated with Darlington Refurbishment.
- An increase in rate base to reflect the inclusion of Construction Work In Progress ("CWIP") for the Darlington Refurbishment Project as presented in Ex. D2-T2-S2.
- The recovery of the difference between forecast 2010 non-capital costs associated with the Darlington Refurbishment project and the costs underlying the payment amounts established in EB-2007-0905, as explained in Ex. H1-T2-S1.

OPG intends to undertake capital expenditures related to the Darlington Refurbishment and the Darlington Campus Master Plan (Ex. D2-T2-S1, Chart 2, page 12). The proposed Darlington Refurbishment capital expenditures in the test period are $105.2M in 2011 and $255.8M in 2012.

4.5.3 OPG's Decision To Proceed With The Darlington Refurbishment Project Reduces The Test Period Revenue Requirement By More Than $197 Million

The OPG Board of Directors approved the decision to proceed with the Darlington Refurbishment Project on November 19, 2009 (Ex. D2-T2-S1, Attachment 1, page 5). Because of the size, scope and duration of this project, the project will proceed in phases with each phase having its own milestones, deliverables and releases of funds. Deliverables in each phase will be achieved prior to moving to the next phase of the project. On November 19, 2009, OPG's 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 (L-10-008). The use of a phased release strategy is a prudent approach to the management of large projects that allows OPG's management and Board of Directors to provide consistent and appropriate oversight to this significant project.

In terms of revenue requirement impacts in this proceeding, Darlington Refurbishment produces an overall revenue requirement decrease of $197.1M during this test period. The drivers of this overall reduction are summarized in Chart 1 of Ex. D2-T2-S1, page 3, which is reproduced below.

Chart 1 Revenue Requirement Impact of Darlington Refurbishment Project ($M)

Line No.	Description	Test Period Revenue Requirement Impact
		(a)
	PRESCRIBED FACILITIES	
	Return on Rate Base:	
1	**Accretion Rate on Lesser of ARC and UNL**	73.2
2	**CWIP in Rate Base Impacts**	32.7
3	**Extension to Darlington Service Life Impacts**	7.3
4	**Total Return on Rate Base Impact**	113.3
	Depreciation Expense:	
5	**Asset Retirement Costs**	(181.1)
6	**Extension to Darlington Service Life Impacts**	(48.5)
7	**Total Depreciation Expense Impact**	(229.6)
	Other Expenses:	
8	**Darlington Refurbishment Project OM&A**	10.4
9	**Used Fuel Storage and Disposal Variable Expenses**	8.2
10	**Total Other Expenses**	18.6
	Income Taxes:	
11	**Accretion Rate on Lesser of ARC and UNL**	25.3
12	**CWIP in Rate Base Impacts**	5.2
13	**Extension to Darlington Service Life Impacts**	1.2
14	**Depreciation Expense on Asset Retirement Costs**	(62.8)
15	**Used Fuel Storage and Disposal Variable Expenses**	2.8
16	**Depreciation Expense on Darlington Service Life**	(16.8)
17	**Total Income Tax Impact**	(45.0)
18	**Total Revenue Requirement Impact - Prescribed Facilities**	(142.7)
	(line 4 + line 7 + line 10 + line 17)	
	BRUCE FACILITIES	
19	**Rate Base**	0.0
20	**Depreciation Expense Impact: Asset Retirement Costs**	(40.2)
	Other Expenses:	
21	**Accretion**	(18.3)
22	**Used Fuel Storage and Disposal Variable Expenses**	4.2
23	**Total Other Expenses Impact**	(14.1)
	Income Taxes:	
24	**Impact on Bruce Facilities' Income Tax Calculation**	13.9
25	**Impact on Prescribed Facilities' Income Tax Calculation**	(14.0)
26	**Total Income Tax Impact**	(0.1)
27	**Total Revenue Requirement Impact - Bruce Facilities**	(54.4)
	(line 19 + line 20 + line 23 + line 26)	
28	**Total Revenue Requirement Impact of Darlington Refurbishment Project**	(197.1)
	(line 18 + line 27)	

The major drivers of the revenue requirement reduction are lower depreciation expense as a result of extending the station's life and the consequent impact on the lower asset retirement obligation and asset retirement cost ("ARC"). The refurbishment also produces significant regulatory tax reductions. These reductions are partially offset by the return on the increased amount of ARC and OPG's proposal to include CWIP in rate base (see Section 10.2.3). Reductions in Bruce ARC, depreciation and accretion expense due to a lower percentage of common waste disposal costs being allocated to the Bruce facilities also work to reduce the revenue requirement.

4.5.4 OPG's Phased Approach To Managing The Darlington Refurbishment Project

OPG began the initiation phase of the Darlington Refurbishment project in late 2007. The purpose of that phase was to assess the feasibility of the project, and make a preliminary determination of its scope, timing and cost (Ex. D2-T2-S1, Attachment 4, pages 16-17). One of the deliverables of the initiation phase was: "Prepare a recommendation with respect to proceeding to refurbish the Darlington station to OPG Senior Management, OPG's Board of Directors and Shareholder. Support this recommendation through the completion of a Business Case Summary ("BCS")." (*Id.*) This deliverable was completed in November 2009 and formed the basis of the OPG Board of Directors' approval to proceed with the project and the Province's endorsement of that decision.

The work completed in the initiation phase included an Economic Feasibility Assessment of Darlington Refurbishment (Ex. D2-T2-S1, Attachment 4), which led to approval by the OPG Board to release funds needed to move into the definition phase to commence preliminary planning work. Taking the project forward to the definition phase allows its costs to be capitalized. The preliminary planning work includes completion of the Environmental Assessment and Integrated Safety Review, initial infrastructure projects needed to support the refurbishment outages and that form part of the Darlington Site "Campus Master Plan", development of the project's contracting and labour strategies and establishment of project governance (*Id.*). The next approval of the definition phase will allow for detailed planning work to commence, which will produce detailed engineering estimates, outage preparation plans, and an Integrated Implementation Plan for CNSC approval. This detailed planning stage will result in a release quality estimate of project cost and schedule and an execution strategy.

The Outage Preparation and Execution phases will include the hiring and training of project staff and the execution of all contracts necessary to undertake the refurbishment. A detailed project execution schedule will be developed as well as a Business Case Summary for the first unit during the Outage Preparation phases and prior to approval to move to the Execution Phase. Detailed schedules, plans and business cases for each of the subsequent units will follow culminating in project close-out activities once all four units have been refurbished.

OPG's phased approach provides a built-in mechanism to control the progress of the project to ensure adherence to schedule and costs. At each phase, the project will be further reviewed by OPG's management and Board of Directors. This gated approach to approval of work and the release of funds is consistent with industry best practice (Tr. Vol. 7, page 50; Tr. Vol. 8, pages 66-68).

4.5.5 Darlington Refurbishment Will Provide An Economic Source Of Baseload Generation

OPG has completed an Economic Feasibility Assessment of Darlington Refurbishment and concluded with very high confidence that the project will have a Levelized Unit Energy Cost ("LK") of less than 8 cents per kilowatt hour ($2009) (Ex. D2-T2-S1, Attachment 4). This economic assessment and phased release strategy provided the basis on which the OPG Board of Directors approved Darlington Refurbishment project. The assessment concludes that the project is more economic than other baseload generation alternatives such as new nuclear development or combined cycle gas generation. Based on OPG's projected LUEC of between 6 and 8 cents/kWh, the OPA concurred with OPG's assessment that Darlington is an economic alternative in comparison to the cost of combined-cycle gas turbines and went on to state that: "Other types of baseload resources such as new nuclear or renewable sources are also expected to have higher cost than Darlington refurbishment." (Ex. F2-T2-S3, Attachment 2).

To arrive at the projected LUEC, OPG has completed its initial evaluation of the project to estimate:

- Refurbishment Scope, Cost, Duration and Timing.
- Expected Life of each unit post-refurbishment.
- Forecast annual operating costs post-refurbishment, including Operation, Maintenance and Administration costs, On-going Project (Capital & OM&A) costs, Outage costs, Fuel

costs, Nuclear Waste Management and Decommissioning (Provisions) costs and Overhead (Nuclear and Corporate) costs.

- Forecast Performance post-refurbishment (annual capacity factor/capability factor).
- Economic Indices (e.g., labour and material escalation rates, appropriate discount rate) (Ex. D2-T2-S1, Attachment 4, page 23).

In addition, OPG has completed sensitivity analyses and statistical analysis to develop a high degree of confidence in the estimated LUEC range.

Based on the foregoing information, OPG requests that the OEB approve the requested changes to the test period revenue requirement specifically set out above. While OPG recognizes that approval of these revenue requirement changes will not eliminate the potential for a later prudence review, OPG does believes that by adopting the proposed overall revenue requirement reduction associated with Darlington Refurbishment, the OEB will be endorsing the view of the Province and the OPA that proceeding with the Darlington Refurbishment at this time and in the manner contemplated by OPG is in the public interest (Tr. Vol. 13, page 87). OPG submits that the OEB should recognize the high probability that, based on the analysis undertaken, this project is economic and will be implemented and approve the resulting revenue requirement decreases.

4.5.6 New Nuclear At Darlington

OPG plans to complete the process of gaining acceptance of the Environmental Impact Statement and approval of the Licence to Prepare Site from the federally appointed Joint Review Panel in 2010 (Ex. D2-T2-S1, page 15). This activity forms the majority of the OM&A expenditures related to new nuclear at Darlington for 2010.

As a result of the uncertainty about when the government will resume the new nuclear procurement process, OPG's application does not forecast spending (capital or OM&A) on new nuclear at Darlington during the test period (Ex. D2-T2-S1, page 16). Any test period expenditures related to new nuclear that arise will be recovered either through a cost recovery mechanism established by the Province for new nuclear or, if no such mechanism is established, through the Nuclear Development Variance Account.

5.0 COMPENSATION AND BENEFITS

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

OPG's wages, salaries, pension and other benefits (together "compensation and benefits") are appropriate for the scope and complexity of the regulated business. OPG's compensation and benefits expense is driven by a number of factors. OPG requires highly skilled employees and these employees have high ongoing training needs. It also has a large proportion of unionized employees (90 per cent) whose compensation and benefits are set by collective agreements established through collective bargaining. OPG will be facing significant demographic challenges in the next five to ten years that will increase compensation and benefits cost pressures. OPG is committed to maintaining a competitive, equitable and cost effective compensation and benefits program which will enable OPG to attract, retain and engage employees required to fulfil OPG's goals and objectives.

5.1 OPG'S EMPLOYEES

At the end of 2009, OPG had approximately 12,000 regular staff. Of this number, approximately 10,000 work in or in support of the regulated business units with some 95 per cent of these employees (9,500) associated with the Nuclear business (Ex. F4-T3-S1, page 2, Chart 1).

In order to operate OPG's mix of generation technologies, staff must be highly skilled, and must possess a wider array of skills and knowledge than employees in many other utilities. In particular, because the vast majority of OPG employees' work is related to nuclear generation, they require extensive knowledge, adherence to very detailed procedures, particular skills and comprehensive training unique to the nuclear industry (Tr. Vol. 9, pages 124-125). OPG's workforce is comprised of engineers, scientists, other professional staff, and skilled trades people. Approximately 8,760 employees (73 per cent of OPG's total employee population) require post secondary education to perform their jobs. These highly skilled employees are in demand across the country, and OPG must compete for these employees with Bruce Power and other private generators and energy service organizations as well as the general marketplace.

OPG has a mature and experienced workforce with half its employees over the age of 47 and over half with greater than 17 years of service. A significant portion of current employees are eligible to retire. As a result, OPG's planning assumptions indicate that the company will be facing significant resourcing gaps over the next five years. OPG estimates that for the company as a whole, 20 per cent to 25 per cent of staff will need to be replaced between 2010 and 2014 due to retirements and terminations.

In light of the demands placed on OPG's workforce and the skills, education and training that are required to operate, maintain and renew OPG's prescribed facilities, the compensation and benefits that they receive are appropriate and should be approved by the OEB.

5.2 COMPENSATION FOR OPG'S UNIONIZED EMPLOYEES

OPG is a heavily unionized environment, with approximately 90 per cent of staff belonging to either the Power Workers' Union ("PWU") or the Society of Energy Professionals ("Society"). Of this 90 per cent, approximately 60 per cent belong to the PWU and approximately 30 per cent belong to the Society. For the regulated operations, the proportion of staff in Management (10 per cent), the PWU (60 per cent) and the Society (30 per cent) is essentially the same as for the company as a whole.

Pursuant to the Ontario *Labour Relations Act*, OPG, as a successor employer to Ontario Hydro, was required to adopt the collective agreements covering the employees transferred to OPG from Ontario Hydro. Thus the PWU and Society collective agreements have been in place since the time of demerger from Ontario Hydro, albeit with some modifications that OPG has negotiated as discussed below. The PWU collective agreement runs through March 31, 2012. The Society collective agreement expires on December 31, 2010. Since compensation and benefits are at the heart of the collective agreements, any changes to these can only be made through the collective bargaining process. Changes in the collective agreements are achieved through negotiation or as the result of arbitration – OPG cannot impose unilateral changes on represented employees (Tr. Vol. 9, page 36).

Collective bargaining is a process of give and take. While OPG begins each round of bargaining with cost containment as one of its goals, this goal must be balanced against other factors required to achieve a productive workforce. For example, early in its history, OPG successfully pursued skill broadening with the PWU so as to improve productivity. As Ms. Irvine explained: “now we have the ability, within the collective agreement, to ask a mechanic to learn rudimentary electrician skills, so that instead of sending out a mechanic and an electrician to say fix a pump, one being to disconnect the motor, the other being to fix the pump, we could send out one employee.” (Tr. Vol. 9, page 123). This initiative exemplifies OPG’s efforts to control its total labour cost by improving the productivity of its workforce. (Tr. Vol. 9, pages 124-125). In a similar vein, OPG negotiated a 12 per cent reduction in the maximum pay level for each pay structure with the Society (Ex. F4-T3-S1, page 9).

As a result of collective bargaining, the general wage increases for the PWU and Society have been between 2 per cent and 3 per cent for the past number of years, and this trend will continue under the existing agreement the PWU into 2012 and is forecast to continue for balance of the test period. A similar level of general increase is forecast for the Society in the test period. Forecast test period compensation costs for the Society also include the cost savings from the base pay program revisions completed in 2006. The impacts of these revisions will continue into the test period and beyond until all employees who achieved the top of the previous pay bands retire or leave the company.

As discussed below, based on the passage of the *Public Sector Compensation Restraint Act*, OPG recognized the savings associated with the removal of the portion of the management compensation increase for the period before March 31, 2012 that had been included in its test year forecast. (Ex. N-T1-S1, pages 1-2).[3] While OPG is aware of that the Government wants to see similar restraint on the wages of unionized employees and is committed to trying to achieve this goal, in light of the response of unions and arbitrators to date, OPG has no basis on which to change its wage forecast for unionized employees (Tr. Vol. 8, pages 202-204).

In addition to the increase in general wage levels, OPG has forecast an additional 1 per cent increase to account for step progressions and promotions by PWU and Society personnel. This sum covers the annual progression of unionized employees along the steps of their pay grade and promotion to higher paid positions (Tr. Vol. 9, pages 17-19). This figure was calculated to

[3] As discussed in Section 5.3 below, the savings from the elimination of most of the test period increase for management employees ($12M out of $16M) was used to offset the increase in test period CNSC fees ($13M) (Ex. N-T1-S1, pages 1-3).

include the impacts of retiring employees being replaced by lower paid PPPPPPemployees (Tr. Vol. 8, page 205). In any given year, many more employees receive step increases than retire and are replaced by new employees with less seniority.

OPG's compensation for its unionized employees is appropriately benchmarked at the 75th percentile of the market for companies surveyed by Towers Perrin, based on the breadth of skills and knowledge required and the complexity of the jobs that they perform. Comparison with the other Ontario Hydro successor companies demonstrates that OPG has generally performed very well in negotiating pay levels for its unionized employees (Ex. F4-T3-S1, page 9, Charts 5 and 6).

5.3 MANAGEMENT GROUP COMPENSATION

Based on the *Public Sector Compensation Restraint Act*, OPG identified a reduction that encompassed $12M of the $16M included in the test period revenue requirement for management salary increases. The remaining $4M covers increases for that portion of the test period after March 31, 2012, when the legislated two-year salary freeze for management employees expires (Tr. Vol. 8, page 198). OPG did not adjust its revenue requirement request to reflect this change because of an offsetting increase in revenue requirement of $13M associated with increased CNSC fees.

OPG's management compensation was benchmarked against a group of comparators selected to fully meet the recommendations of the Report of the Agency Review Panel (Ex. F4-T3-S1, pages 29-30). This benchmarking found that, when compared with the 50th percentile of the comparator group market, and including both salary and variable incentive compensation, senior executives at OPG are paid below market, and middle management and administrative positions are generally paid at market. Moreover, over the three-year period of 2007 through 2009, OPG's total senior management salaries have declined by approximately 12.6 per cent (J9.7).

As in most companies, OPG's Annual Incentive Plan ("AIP") is a key component of the compensation for non-union employees. Under the AIP, a portion of the total management group compensation is paid on an at-risk basis. Eligible employees earn annual cash awards if key cost control and operational objectives of the corporation, business unit and individual are met during the plan year. The budget for AIP is based on corporate OPG performance and is further influenced by fleet (Nuclear, Thermal, Hydro, and Corporate Functions) performance.

AIP is made up of three components: a corporate scorecard, fleet scorecards, and personal objectives for individual performance. For each performance objective, there are threshold, target, and maximum levels of performance. Individual awards vary depending on corporate, fleet and individual performance, and salary band level.

The AIP undergoes a rigorous review process. After CEO approval, the corporate scorecard targets are reviewed and approved by the Compensation and Human Resources Committee of the OPG Board of Directors. Once performance levels are assessed, the CEO and the Compensation and Human Resources Committee complete a final review and approval of the award for AIP. The results and awards undergo an internal audit each year.

Certain nuclear employees (e.g., Authorized Shift Managers and Authorization Training Supervisors) who are licensed and supervise and train licensed employees also receive a bonus to ensure their compensation does not decline when they enter a management position. Otherwise, it would be very difficult to attract qualified candidates into these positions (Ex. F4-T3-S1, page 15).

5.4 BENEFITS

All employees and pensioners at OPG have health and dental benefits designed to protect them from undue costs associated with illness and to encourage them to take steps to maintain good health. The benefits plan has experienced some pressure recently as fewer services are covered by the provincial government. OPG has been taking steps to both monitor and control benefits and has implemented a number of changes to stabilize costs and to better align benefit provisions with those of the external market (Ex. F4-T3-S1, pages 17-19). Benefit changes for the employees represented by the PWU and Society can only be achieved during collective bargaining.

Examples of the benefit changes implemented include the mandatory use of generic drugs, the use of a drug card at pharmacies, and a requirement for prior approval for uncommon and expensive drug and treatment therapies. As a result of these and other changes, OPG is experiencing less escalation in the cost of its health and dental benefits than other employers.

In 2009, OPG's benefit payments increased an average of 2.9 per cent against an industry average figure of approximately 17 per cent based on information provided by Great West Life (Ex. F4-T3-S1, page 19).

One area in which OPG incurred additional costs relates to the Ontario health premium. OPG was directed, through an arbitration award, to pay the Ontario health premium for all PWU-represented employees and pensioners. This resulted in an additional payment of approximately $6M annually.

5.5 PENSION AND OTHER POST EMPLOYMENT BENEFITS

OPG has a contributory, defined benefit registered pension plan**,** which follows closely the model used by most public sector pension plans. All OPG employees earn and contribute towards their pension package, although the benefit levels are slightly less for non-unionized employees than for union members. In addition, all employees are eligible to receive benefits from the defined benefit supplementary pension plans should their pension promise exceed the limits under the *Income Tax Act* for payment from the RPP. Other post employment benefits ("OPEB") include post-retirement benefits, such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees.

Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions, both economic (e.g., inflation, salary escalation, and health care cost trends) and demographic (e.g., mortality, termination rates, and retirement rates) in accordance with GAAP.

The pension and OPEB costs originally forecasts in OPG's application for 2011 and 2012 were based on discount rates and assumptions in the 2010 - 2014 Business Planning (Ex. F4-T3-S1, page 23, Chart 8). Since the beginning of 2010, these discount rates have declined significantly. This decline has caused an increase in the forecast pension and OPEB costs for the test period. Specifically, the discount rates used to project pension, other post retirement benefits and the long-term disability plan costs have decreased from 6.80 per cent, 7.00 per cent and 5.25 per cent, respectively, to 5.70 per cent, 5.70 per cent and 4.40 per cent, respectively, as of the end of August 2010. These updated estimates of discount rates were provided to OPG by external actuaries.

Using updated forecasts, OPG's total pension and OPEB costs for 2011 and 2012 have been projected by external actuaries as of the end of August 2010. Compared to OPG's original evidence, the total projected increase over the two test years is $251.5M for Nuclear and $12.7M for regulated hydroelectric (Compare Ex. F4-T3-S1, Chart 9 to Ex. N-T1-S1, page 3).[4]

Given the potential for significant variability between the updated forecast and actual pension and OPEB costs, OPG is not proposing to address the projected cost increase by revising the proposed payment amounts or payments riders that were based on its original evidence. Instead, OPG proposes to address the forecast change to pension and OPEB costs through the establishment of a variance account to record the impact of differences between the originally forecast and actual pension and OPEB costs (See Section 11.4.2 below). For the 2011 - 2012 test period, OPG would bring the balance in this account forward for disposition during its next payment amounts application.

6.0 CORPORATE FUNCTION COSTS AND COST ALLOCATION

Issue 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?

Issue 6.10 - Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

Issue 6.12 - Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

6.1 INTRODUCTION

This section presents OPG's corporate function costs, including the asset service fee, and corporate allocations. Corporate function costs cover the centralized activities necessary to the operation of OPG's regulated hydroelectric and nuclear facilities. The asset service fee is the

[4] These figures do not include any offsetting tax savings associated with the deductions for the anticipated increase in pension plan contributions and OPEB benefit payments that OPG would include in the proposed variance account (Ex. H1-T3-S1, page 11).

charge for the use of certain corporate assets required to support OPG's regulated hydroelectric and nuclear facilities. Hydroelectric Central Support Groups costs are included in hydroelectric base OM&A (See Section 3.1 above; Ex. F1-T2-S1, pages 11-18).

The hydroelectric and nuclear revenue requirements include OM&A costs directly assigned and allocated from OPG's corporate groups and asset service fees (Ex. F3-T1-S1, Tables 2 and 3; Ex. F3-T2-S1, page 2, Chart 1 and 2). The test period assigned and allocated corporate OM&A costs are:

- Hydroelectric - $24.8M and $26.3M in 2011 and 2012 respectively, and
- Nuclear - $249.2M and $252.3M in 2011 and 2012 respectively.

The test-period asset service fees are:

- Hydroelectric - $2.1M annually for 2011 and 2012, and
- Nuclear - $24.0M and $23.4M in 2011 and 2012 respectively.

OPG submits that the overall level of corporate support costs and asset service fees allocated to the regulated business units is appropriate and should be approved. Both the cost allocation methodology used by OPG and its implementation have been externally verified by Black & Veatch Corporation ("Black & Veatch") and OPG has fully complied with the OEB's direction regarding cost allocation in EB-2007-0905. The asset service fee methodology used in this application is the same as that approved by the OEB in EB-2007-0905.

6.2 OPG'S CORPORATE FUNCTION COSTS

OPG is structured such that certain corporate groups provide services and incur costs, which are necessary to support the operation of the prescribed hydroelectric and nuclear facilities. Corporate support groups include Business Services and Information Technology ("BS&IT"), Finance, Human Resources, Corporate Affairs, Executive Office, Corporate Secretary, Law, and Corporate Business Development.

The budgets for OPG's corporate groups are established through the corporate business planning process. The level of services required by the regulated hydroelectric and nuclear businesses is established through discussions between the corporate service providers and the regulated businesses (Ex. F5-T2-S1, pages 10-11). OPG benchmarks the costs of its largest corporate functions, specifically, Information Technology, Finance and Human Resources, as a tool to support its annual business planning process and to help establish performance targets. The corporate groups that are benchmarked account for approximately 70 per cent of the corporate costs assigned and allocated to the regulated facilities. The results of corporate function benchmarking show that OPG delivers cost-effective corporate services.

Overall, corporate costs during the 2010 - 2012 period remain constant except for an increase in 2012 due to a 53-week fiscal calendar as compared to a 52-week calendar in 2010 and 2011 (Ex. F3-T1-S1, Table 1). Economic increases over the 2010 - 2012 period are offset by various cost reduction initiatives in the corporate support groups, consistent with OPG's business planning guidelines (Ex. A2-T2-S1). Information Technology has also successfully renegotiated the contract with OPG's service provider to obtain substantial year-over-year productivity improvements which are being used to offset normal cost pressures between 2010 and 2012.

The Corporate Affairs and Corporate Centre areas make up the remaining corporate costs. Corporate Affairs includes Energy Markets, Regulatory Affairs and Strategic Planning, Public Affairs and various other smaller groups. The Corporate Centre includes Law, Executive Office and Corporate Secretary and Corporate Business Development (the costs of this latter function are not allocated or assigned to the regulated facilities). While these two areas have experienced some cost growth over the last few years, much of that is attributable to OPG's non-regulated activities (Tr. Vol. 8, pages 121-22; Ex. L-1-87). In fact, close to half of the Corporate Affairs (48%) and Corporate Centre (44%) costs are allocated to OPG's non-regulated businesses (Ex. F3-T1-S1, Tables 1-3). Activities related to OPG's OEB application are the other large driver of cost increases (Ex. L-1-87).

6.3 CORPORATE COST ALLOCATION

OPG's allocation methodology distributes shared costs among the business units by direct assignment and allocation. Direct assignment is used when OPG can reasonably establish the use of specific employees and other cost items by a particular business unit. Allocations are used when more than one business unit uses an employee or cost item, but the portions used by each cannot be directly established. In these cases, a cost driver is used to allocate the costs. A cost driver is a formula for sharing the cost of a resource among those who caused the cost to be incurred. OPG department managers and the business units were consulted and analyses were prepared to support the specific identification/direct assignment, and in selecting cost drivers to ensure the accuracy of the cost allocation process.

OPG retained Black & Veatch to review and evaluate the cost allocation methodology used to assign and allocate corporate support costs to Nuclear and regulated hydroelectric (Ex. F5-T2-S1). The scope of the assignment also included a review to determine and document OPG's compliance with the OEB's "3-prong test".

Black & Veatch's conclusions regarding OPG's cost allocation methodology and its implementation are as follows:

- The overall approach is appropriate for the business organization of OPG.
- Direct assignment of costs by specific identification and by estimation is based on sufficient information reasonably applied.
- Direct assignments are used wherever possible.
- The costs drivers selected by OPG for those instances where not all costs are directly assigned are appropriate.
- The methodology used by OPG to distribute the corporate costs separates the costs between regulated and unregulated business units in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB.

The Black & Veatch report includes an evaluation of OPG's compliance with the 3-prong test which is summarized as:

1. <u>Cost incurrence:</u> Were the corporate centre charges prudently incurred by, or on behalf of, the utility for the provision of services required by Ontario ratepayers?
2. <u>Cost allocation:</u> Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?
3. <u>Cost / benefit:</u> Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?

Black & Veatch concluded that OPG's cost allocation methodology meets all aspects of the 3-pronged test. With regard to cost incurrence, the Black & Veatch report concludes that service providers tailor their offerings to meet the needs of the service recipients (Regulated

Hydroelectric and Nuclear), and the levels of service they provide are adequate, but not excessive. The centralized support and administrative costs were prudently incurred for the benefit of the service recipients, to enable them to meet the needs of the Ontario ratepayers they serve.

As previously described, Black & Veatch's review concluded that OPG's cost allocation methodology is appropriate. In addition, the report concludes that the service recipients are familiar with the cost allocation methodology, and believe that the resulting cost allocations are accurate. On cost/benefit, Black & Veatch found that service providers explicitly consider both the needs of the service recipients and the benefits and costs of proposed activities in developing their budgets. Overall, Black & Veatch found that OPG's allocated centralized support and administrative functions and service costs meet the requirements of the OEB's 3-prong test.

OPG submits that the level of corporate costs is appropriate and they have been properly allocated to the regulated facilities as validated by Black & Veatch. These costs are reasonable and necessary to support the operation of the prescribed facilities and should be approved.

6.4 ASSET SERVICE FEE

Approximately 98 per cent of OPG's in-service fixed assets are directly associated with specific generation facilities. The remaining assets are either directly associated with a business unit, or are held centrally and are used by both regulated and unregulated generation facilities. The assets held centrally are not included either in rate base or in depreciation and amortization expense, and this Application does not include any depreciation or amortization related to these assets. Instead, the regulated facilities (as well as unregulated facilities) are charged an asset service fee for their use, which is included in OM&A expenses.

Asset Service fees are computed in a cost-based manner. The costs included in the computation of the asset service fees are depreciation expense, certain operating costs, property taxes, and a tax-adjusted return earned on these assets.

The regulated facilities are charged a service fee for the use of the following assets:

- OPG Head Office (located in Toronto, Ontario)
- Kipling Site Building Complex (located in Toronto, Ontario)

- Wesleyville (located in Durham County, Ontario)
- Certain shared IT and Energy Markets Assets (together “IT Assets”)

The costs of these assets are allocated to the regulated hydroelectric and nuclear businesses using the cost allocation approach and methodology previously discussed (Ex. F3-T2-S1, pages 2-7). OPG submits that the cost-based asset service fees it has proposed have been appropriately allocated to the regulated hydroelectric and Nuclear businesses and should be approved.

7.0 CENTRALLY HELD COSTS, OTHER OPERATING COSTS AND BRUCE LEASE COSTS AND REVENUES

Issue 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? – (As it relates to Centrally Held Costs)

Issue 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?

Issue 7.3 - Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

7.1 CENTRALLY HELD COSTS

Centrally held costs are items such as certain pension and OPEB related costs, insurance, IESO non-energy charges and Scientific Research and Experimental Development (“SR&ED”) investment tax credits (Ex. F4-T4-S1, page 1). They are an integral part of the costs of operating the prescribed generation facilities with over 95 per cent of these costs typically being directly assigned to individual business units. Centrally held costs do not represent corporate support costs; they are company-wide costs. These costs are recorded centrally for a variety of reasons, such as to achieve record-keeping efficiency and to maintain proper oversight.

OPG’s centrally held costs are attributed to the regulated facilities through direct assignment or allocation. Like the corporate costs, the attribution of these costs to the regulated facilities was reviewed and validated by Black & Veatch (Ex. F5-T2-S1). The centrally held cost amounts allocated to the regulated hydroelectric business are $22.9M and $25.5M in 2011 and 2012 respectively. The nuclear centrally held cost allocation is $199.0M and $234.3M in 2011 and 2012 respectively. OPG submits that these amounts are reasonable and should be approved.

7.2 IESO NON-ENERGY CHARGES

IESO non-energy costs are charges that are applied to withdrawals of energy from the IESO controlled grid. The charges include the Global Adjustment, transmission charges, the debt retirement charge, the rural or remote electricity rate protection charge, charges associated with IESO administration fees, OPA fees and uplift charges. These charges are not discretionary and currently apply to all withdrawals from the IESO-controlled grid. They are directly assigned to the specific nuclear and regulated hydroelectric facilities (Ex. F4-T4-S1, page 3).

The Global Adjustment is the largest component of the IESO non-energy charges. The Global Adjustment has been increasing mainly due to both the increasing quantity of new generation and declining market prices. Market prices impact the level of the Global Adjustment because most generators in Ontario, with the exception of OPG's unregulated facilities, generally are paid an amount in addition to revenues that they receive from the market to ensure that they receive their pre-established price (Ex. F4-T4-S1, pages 3-4). This additional amount is funded by the Global Adjustment. Thus, payments to these generators increase when market prices fall. Both of these factors have led to the Global Adjustment increasing from about $4/MWh in 2007 to about $31/MWh in 2009.

The recent adoption of O.Reg. 398/10 will change the collection mechanism used for the Global Adjustment. The primary purpose of this regulation is to change the way in which Global Adjustment will be collected for certain large volume customers. The actual financial impacts of this change on OPG will depend on how the eligible large volume customers respond to it. The regulation also exempts electricity withdrawals at the PGS station from the Global Adjustment (O.Reg. 398/10 (11)(3)(a)). As discussed below in the Variance and Deferral Account section, however, the net effect of these changes will be to substantially increase the uncertainty around the level of Global Adjustment that OPG will pay.

The IESO levies non-energy charges on each unit of energy withdrawn by wholesale load customers. As a result, total non-energy charges vary as consumption varies. OPG, consistent with its sustainability mandate, has taken significant steps at its regulated hydroelectric and nuclear facilities to improve energy efficiency in order to reduce its electricity consumption and thus reduce its non-energy charges (Ex. L-1-88; Tr. Vol. 14, page 53).

The various components of the IESO non-energy charge can be difficult to forecast – particularly the Global Adjustment, as noted above (Tr. Vol. 2, page 111). The aggregate total of these charges is extremely difficult to accurately forecast and is beyond OPG's ability to control. Accordingly, as discussed below in Section 11.4.2, OPG is seeking approval for a new variance account to protect both itself and ratepayers from over or under collection of IESO non-energy charges (Ex. H1-T3-S1, pages 8-9).

7.3 OTHER OPERATING COSTS

7.3.1 Tax

OPG seeks approval of test period income tax expense of $58.0M and $129.8M for the regulated hydroelectric and nuclear facilities, respectively (Ex. F4-T2-S1 Tables 1 and 3).

OPG uses the taxes payable method for determining regulatory income taxes for its prescribed assets, as it did in EB-2007-0905. Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement. Regulatory income taxes for the prescribed facilities are determined by applying the statutory tax rate to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities.

For the purpose of determining payment amounts for the regulated hydroelectric and nuclear facilities, income taxes determined for OPG's prescribed facilities are allocated based on each business's regulatory taxable income. This approach is the same as that taken in EB-2007-0905. Income taxes allocated to regulated hydroelectric facilities are presented in Ex. F4-T2-S1, Table 1 and to nuclear facilities in Ex. 11, F4-T2-S1, Table 3.

Regulatory taxable income is computed by making additions and deductions to the regulatory earnings before tax for items affected by different regulatory accounting and tax treatment, applying the same principles used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. Additions and deductions are described in detail at Ex. F4-T2-S1, pages 4-9.

7.3.2 Depreciation and Amortization

OPG requests approval of a test period depreciation and amortization expense of $65.6M and $65.0M for regulated hydroelectric facilities in 2011 and 2012 respectively and $235.4M and $256.4M for the nuclear facilities in 2011 and 2012 respectively (Ex. F4-T1-S1, Tables 1 and 2). The depreciation and amortization expense for the regulated hydroelectric facilities remains stable over the test period. The depreciation and amortization expense for the nuclear facilities decreased significantly in 2010 due to the impacts of the Darlington Refurbishment decision (Ex. F4-T1-S1, Table 2; Ex. F4-T1-S2, page 3). The nuclear expense increases by about 10 per cent over the test period, but remains significantly below the levels approved in EB-2007-0905. The test period level of nuclear depreciation expense is the net effect of the decrease resulting from the Darlington Refurbishment decision and an increase associated with in-service additions.

Approximately 90 per cent of OPG's in-service fixed and intangible assets are directly associated with specific generation facilities. The remaining in-service fixed and intangible assets are either directly associated with a business unit, or are held centrally and are used by both regulated and unregulated generation business units.

As part of its due diligence on the service lives of fixed assets and ultimately the calculation of depreciation and amortization expense, OPG convenes an internal Depreciation Review Committee ("DRC"). The DRC is comprised of representatives from each of the business units with operational expertise as well as staff from finance and regulatory affairs functions. The DRC is accountable for providing a formal engineering, technical, and financial review of asset service lives. The DRC conducts a review of the service lives of generating stations, including Bruce stations, and a selection of asset classes every year, with the objective of reviewing all significant asset classes over a five-year cycle.

OPG's prescribed assets are unique and their end-of-life is best established by OPG's Depreciation Review Committee, which has access to specific knowledge of the technical features of the assets. The determination of the station end-of-life dates for depreciation purposes involves an assessment of the condition of and expected remaining life of certain key components (referred to as "life-limiting components"), in conjunction with an estimate of the expected operation of the station. For the nuclear stations, the life-limiting components are:

steam generators, pressure tubes, feeders and reactor components. Based on the most recent assessments, pressure tubes have been assessed to be the most critical life-limiting component at all three nuclear facilities. A single end-of-life is established for depreciation purposes for all units at a particular station, which is typically based on an average estimated end-of-life dates for each of the units. For regulated hydroelectric stations, dams are considered to be the life-limiting component.

Given the technical and economic assessments underway related to the refurbishment and continued operation of OPG's nuclear facilities, the 2009 DRC considered whether changes to nuclear station and specific nuclear and regulated hydroelectric asset class end-of-life dates should be made for depreciation purposes.

The DRC recommended the extension, effective January 1, 2010, of the estimated average service life of the Darlington units to December 31, 2051 based on three main considerations. First, the extension was based on the OPG Board of Director's decision to proceed with the Darlington Refurbishment Project and begin work on the definition phase of the project and the Province's concurrence with this decision. Second, the technical assessments by Nuclear engineering staff as to the expected end-of-life dates of the four units following refurbishment. Third, the DRC assessed the confidence level as sufficiently high that the refurbishment project would be executed as planned (See discussion in Section 4.2.6, above). This assessment was based on the extensive technical and economic analysis performed by OPG in arriving at the decision to proceed with the refurbishment. The extension to the estimated service life of Darlington, including the impacts on the lives of the related assets within the nuclear asset classes, is expected to decrease OPG's annual depreciation expense for the nuclear facilities by approximately $78M (Ex. F4-1-1, page 6).

The DRC did not recommend any changes to the lives of Pickering A or Pickering B. In relation to Pickering B, a substantial body of technical work remains in order for OPG to be satisfied that there is a high confidence level associated with achieving extended lives for Pickering B's pressure tubes. The DRC will not recommend changing the lives of a nuclear station unless there is a high level of confidence to support the change. (Tr. Vol. 10, page 78). OPG has established that the ongoing operation of Pickering B has implications for the technical and economic feasibility of operating Pickering A. However, the DRC concluded that the uncertainty related to the estimated operating life of Pickering B and the uncertainty related to the potential for investment in modification work at Pickering A to allow it to operate without Pickering B do not provide a sufficiently high confidence to establish a different end-of-life date for Pickering A at this time (Ex. F4-T1-S1, Attachment 1, page 6).

The DRC did not recommend any changes to the end-of-life dates for the Bruce A and B stations for depreciation purposes. There was no sufficiently conclusive new public information available regarding Bruce Power's plans to operate and/or refurbish units not already undergoing refurbishment since the previous DRC review in 2007 (Ex. F4-T1-S1, Attachment 1, pages 6-7).

The DRC's review of the individual hydroelectric asset classes led it to recommend no changes to the estimated service lives of these classes, with the exception of the regulated hydroelectric outdoor structures class (Ex. F4-T1-S1, Attachment 1, page 8). The annual impact on depreciation of the change to the estimated services life of the regulated hydroelectric outdoor structures class was determined to be approximately $0.1M per year. The change was implemented on January 1, 2010.

Overall, the 2009 DRC reviewed asset classes, including those related to Darlington, representing approximately 20 per cent of the nuclear asset net book value as at January 1, 2009. To date, the DRC has reviewed asset classes representing approximately 74 per cent of the nuclear asset net book value as at January 1, 2009 (Ex. F4-1-1, page 8).

7.3.3 Bruce Lease Revenue and Costs

OPG has leased its Bruce A and Bruce B Generating Stations and associated lands and facilities to Bruce Power. The Bruce Lease sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power (including lease payments). In association with the Bruce Lease, OPG and Bruce Power have entered into a number of agreements in regard to the provision of services by OPG to Bruce Power, or by Bruce Power to OPG. The revenues and costs associated with the Bruce Lease and associated agreements are calculated based on the OEB's Decision in EB-2007-0905. This decision held that the Bruce Generating Stations should not be treated as if they were regulated assets. As a result, the revenues and costs associated with the Bruce Lease must be calculated in accordance with GAAP.

The net amounts of Bruce Lease revenues and costs are an offset to the nuclear revenue requirement. For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be $128.1M and $143.0M for 2011 and 2012 respectively (Ex. G2-T2-S1 Table 1). OPG submits that these net revenue amounts are the appropriate forecast for the test period, but, in any event, these forecast amounts will be tracked against actual revenues and costs and trued up via the Bruce Lease Net Revenues Variance Account as discussed below in the Section 11.2.3.

8.0 COST OF CAPITAL

Issue 3.1 - What is the appropriate capital structure and rate of return on equity?

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

Issue 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 in each business?

8.1 INTRODUCTION

This section discusses OPG's capital structure and cost of capital. OPG has applied for payment amounts based on a deemed capital structure of 47 per cent equity and 53 per cent debt as approved by the OEB in EB-2007-0905. OPG has applied the ROE of 9.85 per cent set by the OEB for use in 2010 cost of service applications.

The debt component of OPG's capital structure has similarly been determined using the methodologies approved by the OEB in EB-2007-0905.

OPG has evaluated, but does not support, the use of separate capital structures for its two regulated technologies. The benefits of doing so are, at best, marginal and, as conceded by all parties, no robust methodology exists for the setting of such structures.

In what follows, OPG first reviews the fair return standard and stand-alone principle, followed by a discussion of each of the components of its cost of capital.

8.2 FAIR RETURN STANDARD

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

> "By a fair return is meant that the company will be allowed as 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." (*Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at 192-93 (Lamont J.)).

The Supreme Court of Canada reaffirmed this definition in 1960. Mr. Justice Locke concluded that "the [return] must be sufficient to enable it to pay reasonable dividends and attract capital…"[5] He also concluded that "the obligation to approve rates which will give a fair and reasonable return is absolute".

The absolute nature of the obligation to apply the fair return standard was also endorsed by the Federal Court of Appeal. In TransCanada Pipelines Ltd. v. National Energy Board, the Court agreed that the "absolute" nature of the obligation to approve rates that will enable the company to earn a fair return means that the required return must be determined solely on the basis of the company's cost of equity and is not influenced by any resulting rate impact on customers.[6]

The legal requirement to apply the fair return standard has also been recognized by the OEB. In EB-2005-0421 (Toronto Hydro), the OEB noted that "as a matter of law, utilities are entitled to earn a rate-of-return that not only enables them to attract capital on reasonable terms but is comparable to the return granted other utilities with a similar risk profile" (April 12, 2006, pages 32 to 33). More recently, the OEB in its Cost of Capital Report (EB-2009-0084, page 18) stated that meeting the fair return standard, "is not optional; it is a legal requirement."

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[5] *British Columbia Electric Railway Co. Ltd.* v. *British Columbia (Utilities Commission)*, [1960] S.C.R. 837 at 854

[6] *TransCanada Pipelines Ltd. v. National Energy Board et al.* (2004), 319 N.R. 172 (F.C.A) at paras. 35-36

8.3 THE STAND-ALONE PRINCIPLE

The application of the stand-alone principle to OPG was confirmed by the OEB in EB-2007-0905 (page 142). The essence of that principle is that provincial ownership is not relevant to the establishment of OPG's capital structure. No expert in this proceeding disagreed with this conclusion.

8.4 RETURN ON EQUITY

For 2011 and 2012, OPG has adopted the results of the OEB's EB-2009-0084 Cost of Capital Report. The Cost of Capital Report establishes a revised base ROE and a modified automatic ROE adjustment mechanism for all utilities regulated by the OEB.

OPG has applied the adjusted ROE of 9.85 per cent as set by the OEB for use in 2010 cost of service applications in the OEB's letter of February 24, 2010. When calculating the final payment amounts, OPG proposes that the ROE be updated using data for the month that is three months prior to the effective date of the new payment amounts as required by the OEB's Cost of Capital Report (ex. C1-T1-S1, page 3).

The ROE adjustment formula provides for an ROE for a single year, in the case of OPG's application, 2011. To determine the ROE for 2012, OPG proposes that 2012 data from another independent source, Global Insight, be substituted for the Consensus Economics forecast data.

8.5 COST OF DEBT

The long-term debt supporting OPG's regulated operations is comprised of existing and planned long-term debt issues plus a long-term debt provision (i.e. deemed debt) required to reconcile OPG's regulated debt to the deemed capital structure approved by the OEB in EB-2007-0905.

OPG submits that its cost of long-term debt is reasonable and should be approved. OPG has used the same methodology to determine the regulated portion of existing and planned new debt issues that was approved by the OEB in 2007-0905. For its other long-term debt provisions, OPG has applied the OEB's Cost of Capital Report. To summarize, OPG has applied for the following cost of long-term debt (EX. C1-T1-S1, Tables 1 and 2):

	2011	2012
Existing/Planned Long-Term Debt	5.53%	5.50%
Other Long-Term Debt	5.87%	5.87%

8.5.1 Existing/Planned Long-Term Debt

OPG directly assigns all existing and planned project-related financing to regulated or unregulated operations based on whether the project is related to its regulated assets. The company-wide borrowing portfolio of long-term debt remaining after project-related financing has been directly assigned must be allocated to regulated and unregulated operations for the test period.

OPG has applied the allocation methodology approved by the OEB in EB-2007-0905. In summary, the book value of OPG's net fixed assets (gross fixed assets less accumulated depreciation plus construction work in progress) is the basis for allocating the company-wide borrowing portfolio of long-term debt. The net fixed asset values are adjusted to remove asset values that were financed pursuant to project-specific arrangements, and nuclear liabilities (the lesser of OPG's asset retirement cost and unfunded nuclear liabilities). The adjusted relative net fixed asset ratio is then applied to OPG's company-wide borrowing portfolio of long-term debt to determine the amount of existing/planned debt to be included in the long-term debt component of OPG's capital structure for its regulated assets (Ex. C1-T1-S2, pages 1-2).

Consistent with the approach approved in EB-2007-0905, OPG has used information from its most recent audited financial statements (2009) to develop the allocation factor used in 2011, and 2012. The use of audited 2009 financial information is appropriate because the ratio of regulated net fixed assets to corporate net fixed assets does not change significantly from year to year (see Ex. C1-T1-S2 Table 1, line 13). In addition, this approach is simple and does not require assumptions about corporate net fixed asset growth.

The cost of actual debt is at its embedded cost. For planned new and refinanced corporate debt and project-related debt, the cost for the test period is based on a forecast of the 10-year Long Canada Bond published by Global Insight plus a credit risk spread for OPG of 126 basis points. Overall, OPG forecasts its cost of existing and planned long-term debt at $126.2M and $137.6M for 2011 and 2012, respectively.

8.5.2 Other Long-Term Debt

As discussed above, OPG requires a long-term debt provision in order to reconcile its existing and planned debt to its deemed capital structure. OPG has applied the OEB's Cost of Capital Report to determine that provision. At page 54 of that report, the OEB advised that the deemed long-term debt rate should be used where an electricity distribution utility has no actual debt, and that the rate would be modified in a manner consistent with the changes adopted for the ROE adjustment formula. Since OPG has no actual debt supporting this aspect of its capital structure, use of the OEB's deemed rate is appropriate. OPG has applied this rate to both the 2011 and 2012 test years resulting in costs of $51.5M and $42.6M, respectively.

8.5.3 Cost of Short-Term Debt

OPG’s short-term debt is comprised of the same two main sources of short-term financing described in EB-2007-0905, the commercial paper program and the accounts receivable securitization program (Ex. C1-T1-S3, page 1).

OPG’s commercial paper program is used to fund intra-month working capital requirements. OPG expects to continue to use this source of financing in 2011 and 2012. The borrowing rate under the commercial paper program is market-based, comprised of a 10 basis point dealer fee and a corporate spread over the bankers’ acceptances rate for OPG.

OPG’s other primary source of short-term financing is its accounts receivable securitization program. OPG’s forecast reflects continued borrowing of $250M under this program throughout the test period. The cost of the accounts receivable securitization program, consisting of the banker’s acceptance rate for OPG plus a program fee of 0.775 per cent, is forecast to be $6.9M in 2011 and $10.6M in 2012.

From a liquidity perspective, the availability of different sources of financing provides flexibility in managing short term funding by allowing the borrower to manage the use of their various facilities. The securitization program allows OPG to diversify its source of liquidity at a reasonable cost.

OPG has applied the allocation methodology approved by the OEB in EB-2007-0905. In summary, the ratio of the construction work in progress and non-cash working capital amounts (fuel inventory and materials/supplies) for OPG's regulated operations to the total construction work in progress and non-cash working capital amounts reported in OPG's audited financial statements is used as the basis for allocating company-wide short-term borrowing. OPG has used asset and liability balances from its 2009 audited financial statements (Ex. C1-T1-S3, pp. 4-5).

Based on this allocation, OPG has forecast its short term cost of debt allocated to the regulated facilities at $189.5M for both 2011 and 2012.

8.6 TECHNOLOGY SPECIFIC CAPITAL STRUCTURES

In EB-2007-0905 the OEB considered the appropriateness of setting separate capital structures for OPG's hydroelectric and nuclear technologies. At the time, the OEB had before it evidence from Ms. McShane and Drs. Kryzanowksi and Roberts. Ultimately, the OEB determined that it would set one overall capital structure, concluding that:

- the evidence in the proceeding was not sufficiently robust to set separate cost of capital parameters;
- OPG should consider this issue in its next application; and
- the overall cost of capital for OPG would remain the same with the same ROE applied to both capital structure parameters (EB-2007-0905, pages 160-161).

In response to the OEB's directive, OPG retained Ms. McShane of Foster Associates, Inc. to determine whether or not separate capital structures could be established for OPG's nuclear and regulated hydroelectric business segments with sufficient rigour to enable the OEB to rely on the results in establishing payment amounts. Her detailed report is at Ex. C3-T1-S1.

Ms. McShane took as her starting point, the evidence before the OEB in the last proceeding. As she testified, given that the OEB had already concluded that the evidence in the last case was not sufficiently robust to establish separate capital structures, she undertook an incremental analysis of the issue (Tr., Vol. 11, page 9). This analysis considered five different potential quantitative methodologies for isolating the cost of capital for OPG's regulated hydroelectric and nuclear generation operations. Her analysis concluded that none of the five methodologies was sufficiently robust to serve as a basis for estimating technology-specific costs of capital and technology-specific capital structures for OPG's regulated hydroelectric and nuclear prescribed assets, largely as a result of lack of reliable data. As her report stated:

> In this section, five different quantitative methodologies were considered as potential avenues for isolating the cost of capital for OPG's regulated hydroelectric and nuclear generation operations. Four of the five, the exception being the pure play approach are premised on the CAPM. None of the five proved to be sufficiently robust to serve as a basis for estimating technology-specific costs of capital and thus technology-specific capital structures for OPG's regulated hydroelectric and nuclear prescribed assets (Ex. C3-T1-S1, page 60).

Ms. McShane's analysis also considered a non-quantitative method based on the Standard & Poor's debt ratio guideline matrix for different debt ratings and business risk categories for regulated electric utility and power companies. Here again, she found that this approach did not provide sufficiently robust information to serve as a basis for estimating technology-specific costs of capital (Ex. C3-T1-S1, page 61).

Ms. McShane was the only expert to engage in any form of incremental analysis. Drs. Kryzanowski and Roberts, in comparison, repeated the work they had done in the last case reaching, not surprisingly, substantially the same results. The OEB was not satisfied with the robustness of their methodology in the last payments case, and there is no reason to second guess that determination in this proceeding.

OPG continues to support the use of a single cost of capital for its prescribed facilities. OPG is financed as one company with hydroelectric, nuclear and other generating facilities. Moving away from a single cost of capital would add unnecessary complexity and, given the absence of a robust and analytically sound method for calculating technology-specific costs of capital, would not improve the accuracy in the matching of costs (Ex. C1-T1-S1, page 6). Moreover, moving to technology-specific capital structures will not improve OPG's assessment of project specific risks. These risks are already incorporated into OPG's assessment of project cash flows, a more robust approach than simply applying a technology-specific cost of capital (Ex. L-10-16). Therefore, OPG proposes the continued use of a single cost of capital for its prescribed facilities.

9.0 NUCLEAR LIABILITIES

Issue 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?

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

This section discusses OPG's forecast of nuclear liabilities and how the treatment of those liabilities impacts OPG's revenue requirement. The test period revenue requirement impact of the nuclear liabilities is $291.3M for the prescribed facilities and $110.3M for the Bruce facilities (see Ex. C2-T1-S2, Table 5).

For the test years, OPG proposes to maintain the revenue requirement treatment for nuclear liabilities approved by the OEB in EB-2007-0905 for Pickering, Darlington and the Bruce facilities.[7] As explained fully in EX. C2-T1-S1, page 2, OPG as the owner of the Bruce facilities is responsible for the management of all levels of nuclear waste generated at the Bruce facilities and for decommissioning. However, the revenue requirement treatment approved for the Bruce facilities in EB-2007-0905 differs from that approved for Pickering and Darlington.

The revenue requirement impact of the nuclear liabilities is forecast to decrease significantly in the 2010 - 2012 period compared to the historical years as a result of the changes in the asset retirement obligation ("ARO") and depreciation of asset retirement costs associated with the decision to move to the definition phase of the Darlington Refurbishment project (see Ex. C2-T1-S2, Table 4 and below).

9.1 BACKGROUND

OPG's nuclear liabilities represent the present value of the lifecycle cost of decommissioning and nuclear waste management programs. These lifecycle costs include the fixed cost components of each program as well as the lifetime variable costs for waste already generated.

[7] While OPG is continuing to investigate the impacts of the OEB-approved revenue requirement treatment on its ability to recover the full cost of its nuclear liabilities, OPG has not yet developed any position or policy papers for the OEB to consider in this application. Based on the results of this investigation, OPG may propose modifications to the existing treatment or an alternative treatment in a future application.

The present value of the committed costs is recorded as an ARO on the balance sheet of OPG (Ex. C2-T1-S2, page 2).

To the extent that the ARO increases or decreases from changes in the approved Ontario Nuclear Fund Agreement ("ONFA") Reference Plan or a change in accounting estimates, an equal amount must be recorded as an increase or decrease in the net book value of the assets to which the retirement obligation relates. This addition to net book value is known as an asset retirement cost ("ARC") (C2-T1-S2, page 2). The only exception is the annual incremental waste cost, which increases the ARO, but does not impact the ARC because it is expensed in the year generated.

ARC represents a substantial portion of the net book value of the Pickering, Darlington and Bruce nuclear facilities. The ARC is amortized over the useful life of these assets like any other capital cost. This amortization gives rise to depreciation expense.

The ARO is allocated to the station level based on each of the five programs involved in retiring nuclear stations and managing nuclear waste. These five programs are: decommissioning; used fuel storage; used fuel disposal; low and intermediate level waste ("L&ILW") storage and L&ILW disposal. The ARC is recorded at the station level using the methodologies that are used for the ARO. The allocation of the ARO and ARC for both the prescribed facilities and Bruce facilities is shown in Ex C2-T1-S2, Tables 1 and 2 respectively.

9.2 APPLICATION OF THE APPROVED METHODOLOGY TO THE PRESCRIBED AND BRUCE FACILITIES

As discussed above, OPG proposes to continue the methodology approved by the OEB in EB-2007-0905. Under the methodology applicable to the prescribed nuclear facilities, depreciation expense, variable incremental used fuel costs and variable incremental L&ILW costs are determined in accordance with GAAP (Ex. C2-T1-S2, pages 4-6). The approved methodology also requires that the return on a portion of the rate base equal to the lesser of the unfunded nuclear liabilities and the unamortized ARC be limited to the average accretion rate (Ex. C2-T1-S2, page 6).

For the Bruce facilities, the OEB approved a GAAP approach to determine the net revenue impact for the nuclear liabilities. In summary, the difference is that for Bruce facilities the OEB substitutes the net income determinants of accretion expense and earnings on segregated funds in lieu of a return on the unamortized ARC (rate base) used in determining the revenue requirement for prescribed facilities.

The components of the revenue requirement impact from the nuclear liabilities associated with prescribed and Bruce facilities are detailed at Ex. C2-T1-S2, pages 4 to 9. OPG submits that the amounts proposed should be approved.

9.3 IMPACTS OF THE DARLINGTON REFURBISHMENT PROJECT ON NUCLEAR LIABILITIES

Refurbishment of the Darlington facility will allow for it to operate until the year 2051. The main impacts of the refurbishment decision on nuclear liabilities in the test year are: (a) a decrease in the ARO for Darlington decommissioning as the present value of the decommissioning cost reflects the deferral of decommissioning for approximately 30 years; and (b) an increase in the cost of used fuel storage and disposal activities to account for the incremental volumes of used fuel to be generated. The impact of the change in ARO/ARC results in a reduction in revenue requirement impacts for both the prescribed facilities and the Bruce facilities. The net impact is a decrease of $154.2M (Ex. C2-T1-S2, Table 4).

OPG believes that its position in respect of the GAAP-driven change in revenue requirement is consistent with O. Reg. 53/05, section 8. This section provides that the OEB shall ensure that OPG, “recovers revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.” The calculation of the impacts of Darlington Refurbishment on nuclear liabilities is based on the costs in the currently approved reference plan (Tr. Vol. 11, page 146).

10.0 RATE BASE

Issue 2.1 - What is the appropriate amount for rate base?

Issue 2.2 - Is OPG’s proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

10.1 PRESCRIBED FACILITY RATE BASE

OPG requests approval of the rate base forecasts set out in Exhibit B of the pre-filed evidence. These forecasts are based on the same methodology OPG proposed and the OEB accepted in

EB-2007-09-05. For the regulated hydroelectric facilities, OPG seeks approval for its rate base forecasts of $3,803.4M in 2011 and $3,787.4M in 2012 (Ex. B1-T1-S1 Table 1). For the nuclear facilities, OPG seeks approval for its rate base forecasts of $4,041.3M in 2011 and $4,150.8M in 2012 (Ex. B1-T1-S1 Table 2).

OPG's rate base forecast for the bridge year and test period is established from a forecast of net fixed/intangible assets and working capital associated with the prescribed facilities. The value of fixed/intangible assets in the rate base ("net plant") is an average of the opening and closing net book value balances of the fixed/intangible assets in-service and construction work-in-progress ("CWIP") for designated capital projects during the period (Ex. B1-T1-S1, page 1). The value of forecast fixed/intangible assets in-service is reduced by forecast accumulated depreciation/amortization and retirements/transfers to arrive at the net book value of fixed/intangible assets in-service. Working capital consists of cash working capital, fuel inventory, and material and supplies.

Fixed and intangible assets used by both the regulated and unregulated generation business units are held centrally. These assets are not included in rate base. Instead, the regulated business units are charged an asset service fee for the use of these assets, which is included as an OM&A cost, as discussed above in Section 6.4 (Ex. F3-T2-S1).

With the exception of designated capital projects, fixed assets under construction and intangible assets under development are excluded from the rate base until declared in-service. For the test period, OPG proposes that one designated capital project, the Darlington Refurbishment project, be included in rate base. The Darlington Refurbishment CWIP balance included in rate base is discussed under Section 10.2.

OPG's forecast of net fixed/intangible asset in-service values is established based on the actual property, plant, and equipment values (including intangible asset values) in OPG's 2009 audited consolidated financial statements (Ex. B2-T1-S1, Table 1 and Ex. B3-T1-S1, Table 1). These values are rolled forward based on a forecast of fixed/intangible asset additions, retirements/transfers, and depreciation/amortization on these assets to determine forecasts for 2010, 2011, and 2012. The determination of net fixed/intangible assets is performed separately for the regulated hydroelectric facilities and nuclear facilities.

The depreciation/amortization forecasts for 2010, 2011 and 2012 are determined by applying the estimated services lives and depreciation/amortization policies to the forecast of net opening fixed/intangible asset values in-service for each of the regulated hydroelectric and nuclear facilities. These depreciation/amortization forecasts are presented in Ex. F4-T1-S1, Tables 1 and 2.

OPG's working capital for regulated facilities consists of cash working capital, fuel inventory and materials and supplies. The fuel inventory and material and supplies values for rate base are determined using a mid-year average of opening and closing balances during the period. Cash working capital is determined using a lead/lag analysis. Total working capital forming part of the total rate base for the regulated hydroelectric facilities is forecast to be $22.1M in each of 2011 and 2012 (Ex. B2-T5-S1 Table 1). Total working capital forming part of the total rate base for OPG's nuclear facilities is forecast to be $869.1M in 2011 and $848.5M in 2012 (Ex. B3-T5-S1 Table 1).

Consistent with regulatory and accounting requirements, OPG has appropriately recorded opening balances, forecast in-service additions, depreciation and other adjustments to its net fixed assets in its forecast of rate base for the test period. Similarly, OPG has calculated the working capital component of rate base appropriately, including use of a lead/lag study and forecasts of fuel inventory, materials and supplies. As a result, OPG submits the rate base forecast for the test period should be approved by the OEB.

10.2 CWIP IN RATE BASE

10.2.1 Introduction

OPG seeks approval to include CWIP in rate base for the Darlington Refurbishment project, effective January 1, 2011 (Ex. D2-T2-S2, page 1). This proposal to include CWIP in rate base for the Darlington Refurbishment project results in an addition to rate base of $125.5M in 2011 and $306.0M in 2012 (Ex. B3-T1-S1 Table 1) and has a test period impact of $37.9M on the nuclear revenue requirement.

OPG submits that its proposal to include CWIP in rate base is reasonable and should be approved. The proposal is consistent with the OEB's recent report concerning the regulatory treatment of infrastructure (EB-2009-0152), and will lessen the rate shock experienced by ratepayers when the refurbished reactors start to come into service in about 2020 period.

10.2.2 The OEB Report

On April 3, 2009, the Chair of the OEB issued a statement initiating a consultation process to consider amendments to several existing regulatory constructs with the goal of removing barriers to infrastructure investment in Ontario. In his Statement dated April 3, the Chair indicated:

> The magnitude of current and future utility infrastructure investment has led me to consider how the OEB could create conditions which would foster timely investment by utilities in required infrastructure.

This was followed up with a second Statement from the Chair, a Staff Discussion Paper and stakeholder submissions. On January 15, 2010, the OEB issued EB-2009-0152, a Report of the Board on The Regulatory Treatment of Infrastructure Investment in connection with Rate-regulated Activities of Distributors and Transmitters in Ontario (the “Report”). The Report indicates that the OEB will consider, among other things, applications to include CWIP in rate base on a case-by-case basis, in advance of a project being declared in-service. As concluded in the Report, inclusion of CWIP in rate base is consistent with the Chair’s stated objective above and is an important mechanism that is widely used to reduce barriers to investment by utilities (See, Ex. D4-T1-S1, page 1).

On page 15 on the Report, the OEB explains how the CWIP in a rate base model would work indicating that it would “…allow utilities to apply to include up to 100 per cent of prudently incurred CWIP costs in rate base. This approach allows utilities to recover the interest costs on debt and a return on equity (i.e. the weighted cost of capital) during the construction period. The depreciation or return of investment will continue to be recovered once the project goes into service.” OPG is proposing to adopt the CWIP in rate base model described above for its Darlington Refurbishment project.

10.2.3 OPG’S CWIP Proposal

OPG submits that inclusion of CWIP in rate base for the Darlington Refurbishment project meets the criteria for qualifying investments specified by the OEB in its Report. The project spans a number of years, has material costs (i.e., it is capital intensive) and it will form a significant portion of OPG's rate base once placed into service. Moreover, the risks of the project are similar to those noted by the OEB for green energy projects, which include risks related to project delays, public controversy, and the recovery of costs.

OPG proposes to include capital costs from January 1, 2010, the point at which project costs began to be capitalized, as well as some limited pre-commercial costs. Under OPG's proposal, 100 per cent of the forecast capital in rate base would receive the OEB-approved weighted average cost of capital and any recovery of depreciation on this capital would be deferred until the assets come into service. Additions to rate base over the test period would be based on OPG's capital expenditure forecast for the Darlington Refurbishment project as provided in Ex. D2-T2-S1. Any variance in planned capital expenditures would be covered in the Capacity Refurbishment Variance Account as discussed below in Section 11.4.1.

Darlington Meets the OEB'S CWIP Criteria

In section 3.4 of the Report, the OEB sets out a number of factors that it will evaluate within the context of considering a proposal for alternative regulatory mechanisms. OPG's CWIP proposal meets all of the factors established by the OEB. Factors related to the need for and cost of the project are discussed above in Section 4.5 and further in Ex. D2-T2-S1. Impacts on rate base and the benefits of OPG's proposal in comparison to conventional cost recovery mechanisms are addressed below.

Costs of the Project in Relation to Current Rate Base

The projected cost of the Darlington Refurbishment project is between $6B and $10B (2009$). OPG's nuclear rate base in 2012 is $4.0B (Ex. B1-T1-S1 Table 2). It is clear that the capital expenditures associated with the Darlington Refurbishment project are significant within the context of OPG's nuclear rate base and in comparison to OPG's combined regulated hydroelectric and nuclear rate base of approximately $7.8B.

CWIP is Preferable to the Conventional Mechanisms

CWIP in rate base provides two principal benefits. First, it provides a smoothing effect on rates and thereby mitigates the rate shock that might otherwise occur when a large new plant is placed into service. Second, it can reduce borrowing costs. Both of these benefits apply in the case of the Darlington Refurbishment project.

The inclusion of CWIP means that rates will increase gradually during the construction period consistent with the amount of expended CWIP capital that is included in rate base. This gradual increase mitigates the sudden shock that is typically associated with a multi-year project being completed and added to rate base as a single, large quantity (See Ex. L-14-4). Capitalization of the Darlington Refurbishment project began on January 1, 2010, the first unit is scheduled to be removed from service in 2016 and the last unit is scheduled to be returned to service in 2024.

Table 1 in Ex. D2-T2-S2 and Ex. L-14-4 illustrate the projected rate impacts of including CWIP in rates over the 2011/12 test period, and beyond for the Darlington Refurbishment project. The information beyond the current test period is illustrative only, as elements of the project scope, schedule and cost will only be fully defined at the conclusion of the project's definition phase. It is also important to consider when assessing the analysis of rate impacts provided below that this analysis looks solely at the rate impact of the Darlington Refurbishment project. As with any other utility, OPG would be expected to have numerous other costs pressures during the project period that would also serve to increase rates.

Table 1 indicates that, over the test period, inclusion of CWIP associated with the Darlington Refurbishment project within rate base results in a modest impact of $0.38/MWh on the nuclear payment amount.

As expected, early recovery of refurbishment costs leads to smaller and more gradual rate increases compared to the rate shock associated with the traditional regulatory approach in 2020 when the first unit returns to service. Furthermore, there is a lasting benefit of lower rates post in-service date.

The inclusion of CWIP in rate base will reduce OPG's borrowing costs. An entity's ability to access financing is evaluated on the risks that it faces, including the degree of financial leverage and its standing on a number of standard financial risk metrics (e.g., interest coverage ratios).

In Ex. A2-T3-S1, both of the rating agencies that assess OPG (Standard & Poor's and DBRS) rated OPG's long-term credit rating in the low "A" range. Both agencies referenced OPG's nuclear program and Standard & Poor's specifically referenced weak cash flow metrics.

Similarly, Fitch Ratings noted in a discussion of nuclear plant construction financing: "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk."(Ex. D2-T2-S2 page 9).[8] Clearly, inclusion of CWIP in rate base will improve OPG's interest coverage ratios, would help OPG's ratings, and lower overall financing costs, although the precise impact is uncertain.

Under the traditional regulatory treatment, OPG would carry a very large balance in its Darlington Refurbishment CWIP account for many years. If a long-term balance of this magnitude does not earn the weighted average cost of capital, OPG's shareholder would, in effect, be subsidizing the Darlington Refurbishment project (Tr. Vol 14, page 16).

Performance and Reporting Conditions

OPG expects to be before the OEB for several payment amount applications between this application and the ultimate completion of the Darlington Refurbishment project. Accordingly, it will provide regular updates on project scope, schedule and progress, any variances against budget, and a forecast of future expenditures. As part of these applications, OPG will provide information in both its capital exhibits and in its entries to the Capacity Refurbishment Variance Account, as detailed in Ex. H1-T1-S1 section 6.5, which will account for all capital over or under spend associated with the project. For years in which OPG does not file an application for payment amounts, OPG proposes to provide the OEB with an annual monitoring report, indicating project status (Tr. Vol. 13, pages 159-60).

11.0 DEFERRAL AND VARIANCE ACCOUNTS

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

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

Issue 10.3 – Is the disposition methodology appropriate?

Issue 10.4 – Is the proposed continuation of deferral and variance accounts appropriate?

Issue 10.5 – Should the proposed variance account related to IESO non-energy charges be established?

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[8] Fitch Ratings, U.S. Nuclear Power: Credit Implications, November 2, 2006. Emphasis added.

Issue 10.6 – What other deferral and variance account, if any, should be established for the test period?

11.1 INTRODUCTION

This section discusses:

- the existing variance and deferral accounts and their proposed clearance,
- the proposed re-establishment or continuation of existing accounts, and
- two new accounts for which OPG seeks approval in this application.

With respect to the clearance of balances in the existing variance and deferral accounts, as set out in detail in Ex. H1-T1-S2, OPG is proposing to clear the actual audited balances as of December 31, 2010 rather than the forecast balances. OPG has updated its projected deferral and variance account balances in Ex. H1-T1-S2, Table 1. The update incorporates actual results to date and forecasts for the balance of the year.[9] The sections below cite the updated forecast balances for reference; however, OPG will use the final balances as at December 31, 2010 in the calculation of the payment riders during the finalization of the payment amounts order.

The updated projection for December 31, 2010, including corrections and other adjustments as discussed in Ex. H1-T1-S2, shows a credit balance of ($17.4M) for regulated hydroelectric and a debit balance of $690.1M for nuclear.

OPG proposes continuing existing variance and deferral accounts as noted in section 11.4.1 of this submission.

The two new variance accounts for which OPG requests approval are the IESO Non-Energy Charges Variance Account and the Pension and Other Post-Employment Benefits Costs Variance Account. These two new accounts are discussed in Ex. H1-T3-S1 and further in Section 11.4.2 below.

[9] Updates reflect experience to August 31, 2010 with the exception of earnings on nuclear segregated funds, which reflect experience to September 30, 2010 and form part of the Bruce Lease Net Revenues Variance Account.

11.2 EXISTING DEFERRAL AND VARIANCE ACCOUNTS

The OEB approved 12 variance and deferral accounts in EB-2007-0905 (December 2008), a Tax Loss Variance Account in EB-2009-0038 (May 2009), and two additional accounts in EB-2009-0174 (October 2009) (Ex. H1-T1-S1).

The entries recorded in these accounts in 2008 and 2009 were calculated in accordance with the methodology approved by the OEB in EB-2007-0905 and the other decisions above. The projected additions to these accounts for 2010 (see Ex. H1-T1-S1 Table 1d) are determined in accordance with the methodology approved in the OEB's decision on OPG's Accounting Order Application (EB-2009-0174). In the case of the Tax Loss Variance Account, the additions for 2010 are determined based on the OEB's decision in EB-2009-0038 (ex. L-14-038). OPG has applied interest to the monthly opening balances of these accounts at the interest rates set by the OEB from time to time and is currently using the rate effective July, 2010 for the remainder of the year (Tr. Vol.15, p.75).

11.2.1 Existing Deferral and Variance Accounts Common to Hydroelectric and Nuclear

Ancillary Service Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts

These accounts track variances from actual ancillary services net revenue to the 2008 - 2009 test period forecast reflected in the revenue requirement approved by the OEB. A full discussion of hydroelectric ancillary service revenues is set out at Ex. G1-T1-S1 and a full discussion of nuclear ancillary service revenues is set out at Ex. G2-T1-S1.

Ancillary services include operating reserve, reactive support/voltage control service, automatic generation control and black start capability. OPG has recorded differences between actual ancillary services net revenue for 2008 and 2009 and the forecast amounts approved in EB-2007-0905 for those years in these accounts. The forecast additions for 2010 are consistent with the EB-2009-0174 Decision and Order which requires OPG to compare 2010 revenues to a forecast derived from the 2008 and 2009 values approved in OPG's last rate application (Ex. H1-T1-S1).

For the year end 2010, the forecast balance in the Ancillary Services Revenue Net Revenue Variance – Hydroelectric Sub Account is a credit of approximately $9.5M and for the Nuclear Sub Account the year-end forecast is a debit of approximately $1M (Ex. H1-T1-S2, Table 1).

Income and Other Taxes Variance Account

This account records the financial impact on the regulated hydroelectric and nuclear revenue requirement due to variations in municipal property taxes, payments in lieu of capital taxes, and income taxes resulting from changes in tax rates or rules, new assessing or administrative practices of tax authorities, tax re-assessments for past periods, and court decisions for other taxpayers that affect OPG's tax position.

OPG seeks to credit ratepayers a forecasted amount of $32.7M for 2010 with $7.5M and 25.2M applicable to regulated hydroelectric and nuclear facilities respectively (Ex. H1-T1-S2, Table 1).

OPG has recorded four entries in this account, consisting of (i) an entry based on the results of a tax audit received in mid-2008; (ii) a reduction in income tax rates effective January 1, 2010; and (iii) reductions in capital tax rates during 2010 and (iv) an entry related to unburned nuclear fuel expense audit adjustment (Ex. H1-T1-S2, page 4). The entries are detailed in Ex. H1-T1-S2, Table 6.

Tax Loss Variance Account

OPG seeks approval to recover the balance of $492.0M in the Tax Loss Variance Account, with $78.7M and $413.3M attributable to regulated hydroelectric and nuclear facilities, respectively (Ex. H1-T1-S2, Table 1).

In EB-2009-0038, the OEB ordered the establishment of a Tax Loss Variance Account. The Tax Loss Variance Account records the variance between: (a) "the tax loss mitigation amount that underpins the rate order for the test period" (EB-2009-0038, p. 15) (being the current payment amounts order), and (b) "the lax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payment Decision as to the recalculation of those tax losses".

OPG submits that the Tax Loss Variance Account balance sought by OPG is appropriate, fully accords with the OEB's rulings in EB-2007-0905 and EB-2009-0038 and, therefore, should be recovered in full. The submissions that follow consider the steps in calculating the Tax Loss Variance Account balance.

The determination of the Tax Loss Variance Account balance in accordance with the OEB's rulings is best considered by first understanding the two main parts of the variance calculation established by the OEB - the tax loss mitigation amount underpinning in the EB-2007-0905 Order and the actual tax loss.

EB-2007-0905 Tax Mitigation Amount

The EB-2007-0905 Decision and Payments Amount Order included directions that resulted in a revenue requirement reduction of $341.2M for the April 1, 2008 to December 31, 2009 period.

The reduction consisted of:

- a revenue requirement reduction of 22% of OPG's deficiency (EB-2007-0905; Payment Amounts Order Appendix A, Table 3, Note 3) ($168.7M);
- the tax expense (before gross-up) on the established revenue requirement that was forgone and as a result, no allowance was included in the payment amount. Pursuant to the OEB's directive in EB-2007-0905, OPG established the benchmark regulatory income tax expense for the period April 1, 2008 to December 31, 2009. (Ex. F4-T2-S1, p. 19 and table 9) ($66.0M);
- the foregoing additional revenue must be grossed up for tax using the weighted average tax rate for the period April 1, 2008 to December 31, 2009 ($106.5M).

The total of these three components results in the revenue requirement reduction of $341.2M.

Calculating Actual Tax Loss

In its EB-2007-0905 Application, OPG presented the amount of regulatory tax losses available to be carried forward at the end of 2007 as $990.2M. The OEB directed OPG to recalculate the tax losses to reflect the OEB's findings in its Decision in EB-2007-0905. This recalculation resulted in the amount of the tax losses available to be carried forward at the end of 2007 to be $188.5M.[10]

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

Various adjustments were made to the tax loss amount of $990.2M presented in the evidence in EB-2007-0905 to establish the revised amount of $188.5M based on the OEB's ruling in EB-2007-0905. (Ex. F4-T2-S1 Table 8). These adjustments are:

- A reduction to tax losses due to timing of the PARTS cost deduction consistent with the OEB's requirement set out on page 170 of the EB-2007-0905 Decision, OPG is providing the tax benefit related to the PARTS costs deductions to ratepayers so as to match the timing of the recovery of costs from ratepayers. (-$147M)
- A reduction resulting from the exclusion of Bruce revenue and cost impacts. The OEB determined in EB-2007-0905 (pages 169, 171) that calculation of tax losses should exclude revenues and expenses related to the Bruce lease and that effective April 1, 2008, OPG should not include any income or loss in respect of the Bruce lease. Consequently, OPG removed earnings before tax related to Bruce assets and related additions and deductions to those earnings, resulting in the removal of tax losses. (Ex. F4-T2-S1, Table 16) (-$390.0M).
- A reduction for operating losses borne by the OPG Shareholders in 2005 and 2007. OPG's shareholder was not compensated by the ratepayers for these foregone revenues, and hence should retain the benefit of the associated tax losses. This treatment is consistent with the principle noted by the OEB in its Decision on page 170 that "the party who bears a cost should be entitled to any related tax savings or benefits." (-$234.2M).

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

- Reduction due to an update of the tax information for 2007. The tax information provided in EB-2007-0905 for 2007 was based on OPG's 2007 year-end income tax provision, not its actual tax expense, because the final tax expense was not yet available. The actual 2007 tax expense was determined when OPG filed its income tax returns for 2007 in June 2008. The actual expense was used in computing the tax loss for the purposes of the Tax Loss Variance Account for consistency for all years in the 2005-2007 period. The difference between use of the 2007 income tax provision in EB-2007-0905 and the actual tax expense results in a reduction to the tax losses. (-$37M)
- An addition from allocation of adjustments to the pre-regulation amount. The adjustment of $6.5M represents the difference in the amount of the 2005 tax loss attributable to the period prior to April 1, 2005 as a result of the redetermination of the loss. The original amount attributable to that period was $28.4M (Ex. F4-T2-S1, Table 8), and the revised amount is $21.9M (Ex. F4-T2-S1, Table 7). ($6.5M)

In order to complete the variance calculation prescribed by the OEB and establish the Tax Loss Variance Account balance, the recalculated tax losses of $110.9M for April 11, 2005 to March 31, 2008 must be translated into a revenue requirement reduction of $50.3M, including a gross-up for incremental tax[11] (Ex. H1-T1-S1, Table 4, line 2).

Calculation of the Variance

The difference between the "tax loss mitigation amount that underpins" the EB-2007-0905 Order ($341.2M) and the recalculated tax losses reflected as a revenue requirement reduction ($50.3M) is $290.9M. This is the amount of the entries in the account for the April 1, 2008 - December 31, 2009 period (Ex H1-T1-S1, Table 4, line 3).

Since the 2008-2009 payment amounts continue in 2010, OPG is forecasting to record an addition of $195.0M in 2010. This is an annualized value (12/21) of the $341.2M revenue requirement reduction incorporated in the payment amounts for the 21-month test period of April 1, 2008 - December 31, 2009. This amount combined with the balance of $290.9M

[11] Revenue Requirement Reduction = $110.9 M x tax rate / (1 - tax rate) = $110.9 M x 0.3121 / (1 - 0.3121) = $50.3M

recorded for the April 1, 2008 - December 31, 2009 period results in a total of $485.8M (Ex. H1-T1-S1, Table 4, line 7).

Including adjustments for interest, the balance sought to be recovered by OPG is $492.0M (Ex. H1-T1-S2, Table 1, lines 4 and 17). As shown above this balance has been determined in accordance with the OEB's rulings and is the result of accepted tax and accounting methodologies. As a result, OPG's request for recovery should be granted.

11.2.2 Existing Hydroelectric Variance and Deferral Accounts

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the financial impact of differences between forecast and actual water conditions on OPG's regulated hydroelectric production. The regulated hydroelectric rate is based on a forecast of the total production and the total costs for the regulated hydroelectric facilities in the test period. The production forecast in turn is based on a forecast of water availability. These variables are entered into the hydroelectric production model to determine the forecast energy production (Ex. H1-T1-S1). Details of the production forecast methodology are described in Ex. E1-T1-S1.

OPG pays gross revenue charges ("GRC") to the Ontario Electricity Financial Corporation ("OEFC"), the Niagara Parks Commission, and the Minister of Finance. These payments are based on production. Changes in GRC are also recorded in this account, as changes in production affect GRC and constitute part of the financial impact of the variance in production due to water availability. For a full discussion of gross revenue charges see Ex. F1-T4-S1. For a specific discussion of the GRC component of the variance account, see Undertaking J15.2.

The balance for the Hydroelectric Water Conditions Variance Account for year-end 2010 is forecast to be a credit of approximately $68.9M (Ex. H1-T1-S2, Table 1).

Interim Period Shortfall (Rider D) Variance Account

This account records the difference between the regulated hydroelectric revenue shortfall amount for the period from April 1, 2008 to November 30, 2008, and the regulated hydroelectric payment rider D amounts recovered in the period from December 1, 2008 to December 31, 2009, based on actual regulated hydroelectric production (Ex. H1-T1-S1). There are no entries, with the exception of interest, in this account in 2010. The 2010 year-end balance for this account is forecast to be a credit of approximately $2.3M. (Ex. H1-T1-S2, Table 1)

Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The EB-2009-0174 Decision and Order directed OPG to establish this account on January 1, 2010 to record the over collection of regulated hydroelectric variance account balances that are recovered through the regulated hydroelectric payment amount (Ex. H1-T1-S1). The closing balance for this account for 2010 is forecast to be a credit of approximately $8M. (Ex. H1-T1-S2, Table 1)

11.2.3 Existing Nuclear Variance and Deferral Accounts

Pickering A Return to Service ("PARTS") Deferral Account

This account was established by O. Reg. 53/05 and the approved balance, net of accumulated amortization, from the EB-2007-0905 Decision is $183.8M with a recovery period ending December 31, 2011. With the exception of interest, there were no additions to the PARTS deferral account after 2007. For the first quarter of 2008, OPG amortized the balance in the PARTS deferral account based on costs that were being recovered through the regulated rates approved by the Province, which were in effect until March 31, 2008. Beginning April 1, 2008 the December 31, 2007 balance was amortized on a straight-line basis over 45 months as approved by the OEB in EB-2007-0905. Therefore, the approved December 31, 2007 balance will be fully amortized by December 31, 2011. The EB-2009-0174 Decision and Order approved the continued amortization and recovery of the approved December 31, 2007 balance in this account through the continuation of nuclear payment rider A (Ex. H1-T1-S1). The closing balance to be recovered is forecast to be approximately $33M at the end of 2010. (Ex. H1-T1-S2, Table 1)

Nuclear Liability Deferral Account

OPG incurs costs associated with decommissioning its nuclear facilities and managing used fuel 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 was established in 2007 in accordance with section 5.2(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"). (Ex. H1-T1-S1)

In EB-2009-0905, the OEB approved the recovery of the balance in this account as at December 31, 2007 over a period of 33 months, beginning April 1, 2008. The EB-2009-0174 Decision and Order approved the continued amortization and recovery of the approved December 31, 2007 balance in this account through the continuation of nuclear payment rider A. The 2010 year-end balance for recovery in this account is forecast to be approximately $39M. (Ex. H1-T1-S2, Table 1)

Nuclear Development Variance Account

OPG established a Nuclear Development Variance Account in accordance with section 5.4 of the O.Reg. 53/05. The purpose of this account is to ensure that OPG recovers differences between actual non-capital costs incurred and firm financial commitments made for planning and preparation for the development of proposed new nuclear generation facilities and the amount included in payment amounts for these activities.

The EB-2009-0174 Decision and Order approved the continued amortization and recovery of the approved December 31, 2007 balance in this account in 2010 through nuclear payment rider A. OPG has recorded differences between actual non-capital costs incurred for the development of new nuclear generation facilities in 2008 and 2009 and the forecast amounts approved in EB-2007-0905 in the account. The 2010 entries were calculated using the method approved in the EB-2009-0174 decision (Ex. H1-T1-S1). The balance in this account for year-end 2010 is forecast to be a credit of approximately $105M. (Ex. H1-T1-S2, Table 1)

Transmission Outages and Restrictions Variance Account

The OEB approved the recovery of the balance in this variance account as at December 31, 2007 over a period of three years in EB-2007-0905. The OEB also accepted OPG's proposal to stop recording additional transactions in this account effective April 1, 2008. Therefore, the only transactions in this account from 2008 to 2010 are the application of interest and the recording of amortization expense. After the account balance is fully amortized, the account will end. (Ex. H1-T1-S1)

Capacity Refurbishment Variance Account

This account was established pursuant to section 6(2)4 of O. Reg.53/05 to record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility and the amounts for these purposes included in the approved payment amounts. Entries in this account include expenditures for Pickering B Refurbishment, Darlington Refurbishment, and the Pickering B Continued Operations and Fuel Channel Life Cycle Management projects.

Pursuant to the EB-2009-0174 Decision and Order, the continued accumulation of entries to this account was accomplished by comparing 2010 actual expenditures to a forecast derived from 2008 and 2009 forecast values (Ex. H1-T1-S1). The closing balance for this account for the end of 2010 is forecast to be a credit of approximately $1.3M. (Ex. H1-T1-S2, Table 1)

Nuclear Fuel Cost Variance Account

This account records the difference between forecast and actual nuclear fuel expenses. The variances in 2008 and 2009 were determined in accordance with the OEB-approved methodology, which involves comparing the nuclear fuel cost rate ($/MWh), as reflected in the OEB-approved revenue requirement and production forecast, against the actual nuclear fuel cost rate ($/MWh) applied to the actual nuclear production. The variance was determined by multiplying the difference in the nuclear fuel cost rate by the actual production in each month. The EB-2009-0174 Decision and Order approved OPG's proposal to measure monthly variances in 2010 by taking the monthly difference of actual costs or revenues and the OEB-approved forecasts for the period April 1, 2008 to December 31, 2009 as described in more detail in Ex. E2-T1-S1. The forecast year-end 2010 balance for recovery is approximately $9.3M. (Ex.H1-T1-S2, Table 1)

Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was established by the OEB in EB-2007-0905 and became effective April 1, 2008. This account captures differences between the forecast costs and revenues related to the Bruce lease that are factored into the nuclear revenue requirement, and OPG's actual revenues and costs in respect of Bruce facilities. The projected balance for 2010 was determined in accordance with the methodology approved in the EB-2009-0174 Decision and Order.

The forecast of the Bruce Lease Net Revenues Variance Account year-end 2010 balance to be recovered is approximately $296.6M (Ex. H1-T1-S2, Table 1).

Interim Period Shortfall (Rider B) Variance Account

This account records the differences between the nuclear revenue shortfall amount for the period April 1, 2008 to November 30, 2008 and the nuclear payment rider B amounts recovered in the period from December 1, 2008 to December 31, 2009 based on actual nuclear production (Ex. H1-T1-S1). There are no entries, with the exception of interest, in this account in 2010. The projected year-end 2010 balance for this account to be recovered is forecast to be approximately $6.6M (Ex. H1-T1-S2, Table 1).

Nuclear Deferral and Variance Over/Under Recovery Variance Account

The EB-2009-0174 Decision and Order approved the establishment of this account, effective April 1, 2008, to capture the difference between forecast and actual production during the test period relating to nuclear payment rider A and rider C (and during 2010 related to nuclear payment rider A only). The derivation of the balances in this account is shown in Ex H1-T1-S1 Table 12. The projected year-end 2010 balance for this account for recovery is approximately $10.8M (Ex. H1-T1-S2, Table 1).

11.3 OPG'S PROPOSAL FOR CLEARNING THE DEFERRAL AND VARIANCE ACCOUNT BALANCES

OPG has modified its proposal so as to clear the actual audited balances as at December 31, 2010 rather than the forecast balances (Tr. Vol. 14 pp. 49-50). OPG is providing for an external audit of the actual balances prior to the fixing of the payment amounts and payment riders through the finalization process for the payment amounts order (Tr. Vol. 15, p. 73). Therefore, OPG proposes that the OEB use its actual, rather than forecast, balances as at December 31, 2010 as verified by OPG's auditors for setting the payment riders. OPG does not propose any changes to the recovery periods or methodology set out in Ex. H1-T2-S1.

The expected timing of the OEB's decision would allow OPG sufficient time to have its December 31, 2010 actual balances audited by OPG's external auditors. The auditors' report is expected to be available in early February 2011. The actual balances, the auditors' report and any proposed adjustments to the accounts resulting from the OEB's Decision would be available for intervenors and Board staff to review and comment on during the review process for the payment amounts order. The auditors' report would provide additional assurance to the OEB with respect to the accuracy of the balances. This approach and timing are consistent with the proposed effective date for new payment amounts of March 1, 2011 (Ex. H1-T1-S2, Tr. Vol. 15, pp. 72-75).

OPG is requesting test period payment riders for regulated hydroelectric and nuclear production to amortize audited deferral and variance account balances as of December 31, 2010 over the period of 22 months commencing on March 1, 2011, with the exception of the Tax Loss Variance Account, which will be recovered over 46 months. The requested test period riders will also reflect OPG's estimate of a credit to customers for the over-collection of revenue related to the continuation of the current $2.00/MWh Rider A in January and February 2011 based on forecast production for these two months. Any differences between the estimated and actual amount of over-collection based on nuclear production during these two months will be brought forward for disposition as part of the balance in the Nuclear Deferral and Variance Over/Under Variance Account in the next proceeding.

11.4 CONTINUATION AND ESTABLISHMENT OF NEW ACCOUNTS

OPG proposes to record in the approved variance and deferral accounts the difference between the amounts included in the approved payment amounts and the actual costs and revenues. In addition, OPG proposes to record interest on both existing and new deferral and variance accounts at the rate prescribed by the OEB (Ex. H1-T3-S1).

During the portion of the test period before the effective date of new payment amounts (proposed to be March 1, 2011), OPG will record entries to the existing accounts using the same methods used to derive 2010 entries, pursuant to the Accounting Order in EB-2009-0174 and the Decision in EB-2009-0038.

11.4.1 Accounts OPG Proposes to Continue

OPG requests approval to continue the following existing deferral and variance accounts:

Accounts Common to Hydroelectric and Nuclear

- Ancillary Service Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Income and Other Taxes Variance Account (not addressed in this section)
- Tax Loss Variance Account (not addressed in this section)

Hydroelectric Variance and Deferral Accounts

- Hydroelectric Water Conditions Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

Nuclear Variance and Deferral Accounts

- 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

The following accounts would continue but will only contain entries for amortization and interest, and would end once the balances are fully 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

The need for these accounts and their operation is described in further detail in the remainder of this section.

Accounts Common to Hydroelectric and Nuclear

Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts

This account will record the difference between the forecast ancillary revenues included in the payment amounts and the actual ancillary revenues during the test period. This account needs to continue in order to clear the 2010 year-end balance, and to record additions during the test period as a result of the forecast risks related to these projected revenues.

Hydroelectric Variance and Deferral Accounts

Hydroelectric Water Conditions Variance Account

This account will record the financial impact of differences, including the impact on revenue and GRC, between the water conditions underpinning the approved payment amounts and the actual water conditions experienced during the test period. This account needs to continue in order to clear the 2010 year-end balance, and to record additions during the test period as a result of the water conditions forecast variances.

Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The projected over-collection as at December 31, 2010 will be cleared by the end of 2012. However, this account needs to continue as OPG will its recovers variance and deferral account balances through payment riders based on production that itself is subject to variation.

Nuclear Variance and Deferral Accounts

Nuclear Liability Deferral Account

This account addresses changes in OPG's liability for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel. The ongoing obligations covered by this account relate to the Pickering and Darlington facilities that are owned and operated by OPG. Obligations related to the Bruce A and B facilities that are leased by OPG to Bruce Power are largely captured in the Bruce Lease Net Revenues Variance Account, except for those changes arising prior to April 1, 2008 when the Bruce facilities were still treated as prescribed assets. This account is a requirement under O. Reg. 53/05 and continues to be required to capture the revenue requirement impacts of future reference plan changes between rate applications on prescribed facilities.

Nuclear Development Variance Account

This account is required under O. Reg. 53/05 and its continuation during the test period is required to clear the balance as at December 31, 2010 and to record potential additions during the test period related to ongoing nuclear development activities. These potential additions will capture the difference between the nuclear development expenditures included in the approved payment amounts and the actual expenditures during the test period.

Capacity Refurbishment Variance Account

OPG intends to continue nuclear refurbishment activities over the next several years and proceed with initiatives related to Pickering B Continued Operations. Potential variances in capital and non-capital costs of these projects will be recorded in the Capacity Refurbishment Variance Account. This account is required under O. Reg. 53/05 as found by the OEB in EB-2007-0905.

Among the costs that are covered by this account are the financing costs associated with the Darlington Refurbishment project that OPG has proposed to recover starting in the test period. These costs consist of a rate of return on capital applied to the projected capital expenditures that OPG proposes to include in rate base. To the extent that actual expenditures differ from the forecast amounts included in approved payment amounts, OPG will record the impact of the variance on the financing costs in the Capacity Refurbishment Variance Account.

Nuclear Fuel Cost Variance Account

This account needs to continue in order to clear the 2010 year-end balance and to record additions during the test period. Uncertainty in factors such as the schedules for new uranium production, liquidation of additional inventories, and the pace of worldwide nuclear expansion are expected to result in continuing price volatility and a range of potential market prices (See Ex. F2-T5-S1).

<u>Bruce Lease Net Revenues Variance Account</u>

Certain components associated with the Bruce lease, such as earnings on nuclear segregated funds, are market driven and therefore difficult to predict. The earnings or losses on these funds can have a significant financial impact on OPG's operations. During the test period, this account would record the difference between the Bruce costs and revenues included in the approved payment amounts and the actual Bruce costs and Bruce lease revenues realized. This account needs to continue in order to clear the 2010 year-end balance and to record variances during the test period.

<u>Nuclear Deferral and Variance Over/Under Recovery Variance Account</u>

The OEB approved establishment of this account, effective as of April 1, 2008, in EB-2009-0174 to capture any over or under recovery of approved nuclear deferral and variance account balances. Since balances as of December 31, 2010 are proposed to be recovered through payment riders calculated on a per MWh basis, differences between forecast and actual production during the test period, including the portion of the test period before the effective date of new payment amounts (proposed to be March 1, 2011) during which OPG will continue to receive revenues from nuclear payment rider A, will create a variance.

The OEB approved new payment amounts for OPG in December 2008, which were effective as of April 1, 2008. As a result, OPG had a revenue shortfall for the period April 1, 2008 to November 30, 2008. Rider C was established to allow OPG to recover nuclear payment rider A (for recovery of nuclear variance and deferral accounts) for this period. With the exception of interest and amortization, no additional amounts will be recorded in this account during the test period related to nuclear payment rider C.

11.4.2 Accounts OPG Proposes be Established

As set out in detail in Ex. H1-T3-S1, OPG requests approval to establish two new variance accounts:

- the IESO Non-Energy Charges Variance Account; and
- the Pension and Other Post Employment Benefits Cost Variance Account.

IESO Non-Energy Charges Variance Account

IESO non-energy charges are applied to all load customers in the Ontario wholesale market. They are made up of a number of different components including: Uplift Charges, Debt Retirement Charges, Rural Rate Assistance, Transmission Charges, Global Adjustment, etc. For a detailed description of IESO non-energy charges, refer to Ex. F4-T4-S1.

These charges are incurred by OPG to operate the regulated facilities and cannot be avoided and the energy to which the charges are attached cannot be supplied cost-effectively by an alternate source. Further, they are beyond management's ability to control.

These charges are difficult to forecast for two reasons. First, the charges fluctuate based on the changes in the wholesale market. In particular, the amount of the Global Adjustment, the largest and most volatile of component of IESO non-energy charges, is subject to even greater uncertainty with the enactment of O.Reg. 398/10. As of January 1, 2011, O.Reg. 398/10 will change the method used to collect the Global Adjustment. The impact of this change depends on the behavior of certain large volume electricity consumers and, while unknown at this time, is potentially significant. Second, the charges are based on consumption, which itself can fluctuate hour-to-hour, or month-to-month. As a result of these two factors, the total amount of IESO non-energy charges is very difficult to accurately forecast.

As seen in Ex. F4-T4-S2 Tables 1 and 2, variances in IESO non-energy charges associated with both nuclear and regulated hydroelectric facilities have been material and have occurred in both directions in recent years. A variance account for the total of IESO non-energy charges associated with both nuclear and regulated hydroelectric facilities will protect both OPG and ratepayers from over or under collection of these charges. Starting on the effective date of new payment amounts, proposed to be March 1, 2011, this account will record the difference between the IESO non-energy charges underpinning in the approved payment amounts and the actual IESO non-energy charges.

Pension and Other Post Employment Benefits Cost Variance Account

OPG requests approval to establish a new variance account to be called the Pension and Other Post Employment Benefits Cost Variance Account (Tr. Vol. 14, p. 52). This account would record the difference between the pension and other post employment benefits ("OPEB") costs reflected in OPG's approved payment amounts and the actual pension and OPEB costs for the prescribed facilities and associated tax impacts. For the 2011-2012 test period, OPG would bring the balance in this account forward for disposition during its next payment amounts application.

As discussed in EB-2007-0905, OPG's pension and OPEB costs are difficult to forecast and often result in variances that are material.[12] As indicated in the Impact Statement filed by OPG on September 30, 2010 (Ex. N-T1-S1, pages 2 to 4), the difference between the forecast included in this application for pension and OPEB costs and the updated projection of pension and OPEB costs is substantial (i.e., greater than $250M). This updated projection of pension and OPEB costs for the prescribed facilities is based on a projected actuarial accounting assessment of OPG-wide costs for the test period provided by OPG's external actuaries, Mercer, using data as of August 2010.

The main drivers of variance for pension and OPEB costs are discount rates and pension fund performance. These factors are both difficult to forecast and beyond OPG management's ability to control.

In EB-2007-0905, the OEB noted that, "In the event that OPG's actual pension and OPEB costs during the test period are materially in excess of the amounts included in the revenue requirement, OPG would have the ability to apply to the Board.[13]" The currently forecast variance in these costs is in excess of $250M.

On April 9, 2010 the OEB issued its Decision with Reasons in EB-2009-0096 which included approval of a Pension Cost Differential Account for Hydro One Networks Inc. "to track the difference between the actual pension costs booked using the actuarial assessment provided by Mercer, and the estimated pension costs used in this filing.[14]"

In addition to the differences between forecast and actual pension and OPEB costs, there is expected to be a difference between forecast and actual regulatory tax deductions for pension

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[12] EB-2007-0905, Ex. J1-T3-S1, Page 13. Forecast variances of between $11M under-forecast and $130M over-forecast on a company-wide basis.

[13] Ibid. page 127.

[14] EB-2009-0096 Decision with Reasons, April 9, 2010, page 56.

plan contributions and OPEB benefit payments. As OPG expects its pension plan contributions to be higher than those included in the application, capturing this difference in regulatory tax deductions in this account will partly offset the expected increase in pension and OPEB costs. Accordingly, OPG proposes that the proposed Pension and Other Post Employment Benefits Cost Variance Account also record the difference in the regulatory tax expense resulting from the difference in pension plan contributions and OPEB benefit payments included in determining the tax expense for the prescribed facilities in the OEB-approved payment amounts and the portion of actual pension plan contributions and OPEB benefit payments attributable to the prescribed facilities made by OPG.

In light of the OEB's findings in EB-2007-0905 and EB-2009-0096, OPG is proposing to establish an account to track, for its prescribed facilities, the difference between the actual pension and OPEB costs booked using the actuarial accounting assessments and the forecast of pension and OPEB costs included in the OEB-approved payment amounts, net of associated tax effects. The proposed variance account is symmetrical and would apply equally to positive and negative variances and will result in payment amounts that are more accurate and fair to both OPG and ratepayers.

12.0 DESIGN OF PAYMENT AMOUNTS

Issue 9.1 - Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

OPG is not seeking a change in the design of the payment amounts in this application. In EB-2007-0905, the OEB determined that the nuclear payment amounts should be 100% variable, despite the fact that the great majority of OPG's nuclear costs are fixed. Based on this determination, for the purposes of this proceeding OPG has proposed nuclear payment amounts that are 100% variable based on production. OPG proposes the use of a per MWh payment amount for regulated hydroelectric and nuclear and continuation of the same Hydroelectric Incentive Mechanism approved in the last application.

OPG proposes a separate per MWh rider for regulated hydroelectric and nuclear to clear the approved deferral and variance account balances. OPG has proposed that the final value of the nuclear and hydroelectric riders be determined based on the actual audited balances as at

December 31, 2010. The final balances and the auditors' report on these balances will be available to intervenors as part of the review process for the payment amounts order.

12.1 IMPLEMENTATION

OPG's application seeks implementation of the payment amounts presented in the table below effective March 1, 2011. OPG seeks approval of payment riders based on the audited variance and deferral account balances as at December 31, 2010, also for implementation effective March 1, 2011. The final value of the approved payment amounts and riders will be calculated in the Payments Amount Order based on the OEB's decision on the approved revenue requirement, production forecast and disposition of variance and deferral account balances.

	Regulated Hydroelectric	Nuclear
Payment Amount[15]	$37.38/MWh	$55.34/MWh

OPG is seeking new payment amounts that allow for recovery of the test period revenue requirement for the period March 1, 2011 to December 31, 2012. OPG requests that current payment amounts be declared interim effective March 1, 2011. OPG also requests recovery of the difference between the current payment amounts and the final payment amounts for the period from March 1, 2011 to the actual implementation date of the OEB's order setting final payment amounts.

OPG has discussed the settlement process for the payment amounts arising from the OEB's order in this proceeding with the IESO. Assuming there is no change in the design of the payment amounts, the IESO could invoice for the month of March 2011 based on new payment amounts if the final payment order is issued before March 20, 2011.

13.0 REPORTING AND RECORD-KEEPING REQUIREMENTS

Issue 11.1 - What reporting and record keeping requirements should be established for OPG?

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[15] The final nuclear payment amount will be adjusted to remove $4.9M in 2011 and $3.9M in 2012 from the revenue requirement as a result of the double-counting of the costs allocated to Pickering B Continued Operations for the Fuel Channel Life Cycle Management project (Tr. Vol. 5, page 3)

OPG's Application does not seek approval for any reporting or record keeping requirements. In OPG's submission, a separate process should be initiated if the OEB wishes to establish reporting and record keeping requirements for OPG. There are a number of details that would have to be determined to establish appropriate reporting and record keeping requirements for OPG that are most efficiently established in a separate process (Ex. L-1-149).

In response to Board Staff inquiries, OPG has indicated 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, consistent with the timelines established in the *Securities Act* for filings with the Ontario Securities Commission. In addition, if OPG produces an annual report in a given year, OPG would be able to file it with the OEB upon its release (Ex. L-1-149).

OPG opposes providing audited financial statements for the prescribed facilities or a trial balance for the prescribed facilities on an annual basis, and OPG submits that these should not be required. As this hearing demonstrated, these statements have extremely limited utility. OPG's systems were not designed to record the information required for their production. As a result, they are extremely time consuming and expensive to produce and require many assumptions (Ex. L-1-149; Tr. Vol. 15 page 94).

14.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

> **Issue 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?

> **Issue 12.2** - What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

OPG proposes that following the decision in the current proceeding, it would file an application setting out its proposal for incentive regulation. A hearing, including the opportunity to file expert evidence, an interrogatory process and a technical conference would lead to a decision by the OEB on the form of incentive regulation that would apply to OPG. OPG would incorporate the results of that decision into a cost of service application that it would make for the post-2012 period, which would set the base rates for incentive regulation and address any remaining implementation issues (Ex. L-1-150).