Réponses du Transporteur et du Distributeur à la demande de renseignements numéro 1 de la Fédération canadienne de l'entreprise indépendante («FCEI») – Partie 2

Annexes

Réponses aux questions 7.1 et 7.3

Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets

Prepared for:

Ontario Energy Board

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Executive Summary

The Ontario Energy Board (OEB or Board) engaged Power Advisory LLC (Power Advisory) to identify, evaluate and analyze Incentive Regulation Mechanism (IRM) options for setting payments for Ontario Power Generation's (OPG's) "prescribed" generation facilities, comprised of six hydroelectric facilities and three nuclear facilities that provide a total of 9,908 MW of capacity to the Ontario market.

Ontario Regulation 53/05 (O. Reg 53/05) established initial pricing parameters for the prescribed facilities as well as rules to be applied by the Board in setting subsequent payment amounts. These rules provided discretion as to the "form, methodology, assumptions and calculations" to be applied by the Board in setting payment amounts. However, the Board has clearly stated from the outset that IRM is the preferred long-term methodology for setting payments for these facilities, citing a desire to encourage efficiency in OPG's operations and investments.[1]

The purpose of this report is to lay the groundwork for consideration of incentive approaches by the Board, OPG and other stakeholders. This is accomplished by identifying potential incentive approaches that reflect the particular circumstances of OPG's hydroelectric and nuclear facilities and by assessing these options. This assessment will consider the prospect that specific IRM options will promote more efficient investments and operations by OPG and contribute to the OEB's goals of protecting consumer interests in electricity pricing and promoting economic efficiency.[2]

The most important conclusion is that IRM should be applied to OPG's regulated nuclear and hydroelectric businesses. With respect to nuclear operations, the benchmarking analyses that have been performed indicate that OPG's nuclear units have performed poorly, and dramatically so with respect to the Pickering units. Although the performance concerns are primarily associated with the Pickering units, the IRM should include all units in order to focus on efficiency improvements across the fleet and to avoid any incentive to shift costs among units. Further, the ScottMadden benchmarking results indicate that improvements in this performance can be achieved by OPG actions and are not entirely beyond the control of OPG, although certain challenges related to the condition of the units have been acknowledged. It should be noted that the ability of the plants to operate safely has not been called into question.

With respect to the hydroelectric business, the existing Hydroelectric Incentive Mechanism (HIM) has been working fairly well although there are concerns as to whether more could be done to mitigate the potential adverse consequences that result from Surplus Baseload Generation (SBG) conditions. These conditions are largely beyond OPG's control and Power

[1] November 30, 2006 Board Report, "*A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation, Inc.",* page 1.

[2] Ontario Energy Board Act, Statutes of Ontario, Ch. 15, Schedule B, 1(1)1., 2.

Advisory has not identified an improvement to the mechanism that would address this issue in a straightforward manner. Power Advisory has also noted that cost efficiencies have not been a major concern with respect to OPG's hydroelectric business although a price cap mechanism may be successful in generating incremental OM&A efficiencies.

Based on our assessment of the options presented in this report, and in consideration of how they might be combined to achieve a comprehensive outcome that will benefit Ontario and its electricity customers, Power Advisory makes the following recommendations:

Nuclear Operations:

- Establish the cast-off prices based on the cost-of-service, reflecting a modest increase in the Unit Capability Factor (UCF) of the Pickering units.
- Adopt price determination method Option N2, with OM&A and other cost efficiencies and increased production reflected in the calculation of prices in years 2 through the end of the IRM term (assumed to be at least four years in total).
- Consider an additional incremental targeted incentive(s) directed toward continuous improvements in UCF and Forced Loss Rates (FLRs) at the Pickering and Darlington plants, considered as separate plants and thus potentially resulting in a reward for progress made in one plant being partially offset by a penalty for a degradation of performance at the other plant.
- Establish a variance account for the DRP, with an incentive mechanism that is aligned with any cost and completion date incentives that are in place for the Engineering, Procurement and Construction (EPC) contractor and other key vendors.
- Provide for timely recovery of existing fixed costs for Darlington units while they are out of service; fixed costs attributable to the refurbishment would be placed in a deferral account for recovery after the units return to service.

Hydroelectric Operations:

- Establish a traditional price cap mechanism (Option H5) with a modest "x-factor" that encourages cost efficiencies without threatening the continued future availability of OPG's prescribed hydroelectric facilities;

- Retain the HIM (Option H1), with incentive payments that are proportionate to the benefits that are reflected in customer bills, thus retaining the existing sharing above a capped amount approach; and

- Continue the practice of after-the-fact reviews of OPG's performance during SBG conditions, making adjustments to a variance account if it determines that OPG could have reasonably taken actions to mitigate the impact of SBG conditions.

<u>OPG Financial Performance</u>:

- Implement an earnings-sharing mechanism (Option N6) that applies to the entirety of OPG's prescribed facility operations with a relatively broad deadband (e.g., plus or minus 250 basis points) around the authorized return and symmetrical sharing above and below the deadband;

- Incorporate a z-factor to account for the potential for the impact of extraordinary exogenous events that are beyond the control of OPG management and were not foreseen when the plan was implemented; and

- Implement an off-ramp that terminates the IRM should OPG's financial performance be so impaired as to threaten OPG's ability to attract capital to finance its construction budget on reasonable terms.

Power Advisory acknowledges that these recommendations represent a departure from past practices either in Ontario or elsewhere, and particularly with respect to the recommendation to implement a target revenue requirement under Option N2 that incorporates cost and production efficiencies in years 2 through the end of the IRM term. These recommendations attempt to reflect the unique role of OPG's assets and its position with the Province of Ontario as its sole shareholder.

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List of Acronyms

AGC	Automatic Generation Control
Board	Ontario Energy Board
CANDU	Canadian Deuterium Uranium
CAPEX	Capital Expenditures
CoS	Cost of Service
DRP	Darlington Refurbishment Project
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EPC	Engineering, Procurement, Construction
EUCG	Electric Utility Cost Group
ESM	Earnings Sharing Mechanism
ECA	Electricity Competition Act
FLR	Forced Loss Rate
GA	Global Adjustment
GDP-IPI FDD	Gross Domestic Product Implicit Price Index for Final Domestic Demand
GRC	Gross Revenue Charge
HIM	Hydroelectric Incentive Mechanism
HOEP	Hourly Ontario Energy Price
IAEA	International Atomic Energy Agency
IESO	Independent Electricity System Operator
IR	Incentive Regulation
IRM	Incentive Regulation Mechanism
kWh	Kilowatt Hour
MPMA	Market Power Mitigation Agreement
MW	Megawatt
MWh	Megawatt Hour
O&M	Operations & Maintenance
OEB	Ontario Energy Board
OPG	Ontario Power Generation
PGS	Pump Generating Station
PHWR	Pressurized Heavy Water Reactor
PWR	Pressurized Water Reactor
ROE	Return on Equity
SBG	Surplus Baseload Generation
TFP	Total Factor Productivity
UCF	Unit Capability Factor
VBO	Vacuum Building Outage
WANO	World Association of Nuclear Operators
WMSC	Wholesale Market Service Charges

1. Introduction and Purpose

1.1 Purpose

The Ontario Energy Board (OEB or Board) engaged Power Advisory LLC (Power Advisory) to identify, evaluate and analyze Incentive Regulation Mechanism (IRM) options for setting payments for Ontario Power Generation's (OPG's) "prescribed" generation facilities, comprised of six hydroelectric facilities and three nuclear facilities that provide a total of 9,908 MW of capacity to the Ontario market.

Ontario Regulation 53/05 (O. Reg 53/05) established initial pricing parameters for the prescribed facilities as well as rules to be applied by the Board in setting subsequent payment amounts. These rules provided discretion as to the "form, methodology, assumptions and calculations" to be applied by the Board in setting payment amounts. As described in Chapter 2.1, the Board has applied a cost-of-service (CoS) methodology in each of the first two subsequent payment amount reviews. These proceedings provided the Board and other stakeholders with the opportunity to examine OPG's costs in detail, establishing a necessary foundation before embarking on an IRM approach.[3] However, the Board has clearly stated from the outset that IRM is the preferred long-term methodology for setting payments for these facilities, citing a desire to encourage efficiency in OPG's operations and investments.[4] Moreover, it indicated in its 2011-2014 Business Plan that it would like to explore the merits of implementing an alternative approach for setting prices[5] and then subsequently expanded on this commitment in the Board's decision on OPG's 2011/2012 CoS application (EB-2010-0008):

> "The Board finds that, given the current situation, it is not practical to implement incentive regulation in time for implementation for payments for 2013. The Board therefore expects OPG to file another cost of service application for the 2013 and 2014 years.
>
> However, the Board concludes that incentive regulation beginning in 2015 should be considered. To facilitate this, the Board will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG. This review may include options and preferences on the general type(s) of incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. This preliminary process to consider

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[3] November 30, 2006 Board Report, "*A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation, Inc.",* page 11, where the Board stated, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula.

[4] ibid., page 1.

[5] Ontario Energy Board 2011-2014 Business Plan, January 31, 2011, Pages 9-10.

incentive regulation mechanisms in the context of OPG's unique circumstances will allow for input from OPG and all other interested stakeholders."[6]

The purpose of this report is to lay the groundwork for consideration of incentive approaches by the Board, OPG and other stakeholders. This is accomplished by identifying potential incentive approaches that reflect the particular circumstances of OPG's hydroelectric and nuclear facilities and by assessing these options. This assessment will consider the prospect that specific IRM options will result in more efficient operations and contribute to the OEB's goals of protecting consumer interests in electricity pricing and promoting economic efficiency.[7] Ideally, the report will enhance the ability of all stakeholders to participate efficiently and effectively in a stakeholder conference and any subsequent Board proceedings.

1.2 OPG's Prescribed Generation Facilities

OPG's prescribed generation facilities are specified in O. Reg. 53/05. They include the following three nuclear generating stations and six hydroelectric facilities:

	Capacity	In-Service Dates
Nuclear Facilities:		
Pickering A	1,030 MW	1971-72
Pickering B	2,064 MW	1983-86
Darlington	3,512 MW	1989-1993
	6,606 MW	
Hydroelectric Facilities:		
Sir Adam Beck I	417 MW	1922
Sir Adam Beck II	1,499 MW	1954
Sir Adam Beck PGS	174 MW	1957-58
DeCew Falls I	23 MW	1898
DeCew Falls II	144 MW	1943, 1948
R. H. Saunders	1,045 MW	1958-59
	3,302 MW	
Total Capacity	9,908 MW	

6 EB-2010-0008, March 10, 2011 Decision with Reasons, page 156.

7 *Ontario Energy Board Act*, Statutes of Ontario, Ch. 15, Schedule B, 1(1)1., 2.

These facilities represent approximately 28 percent of total Ontario capacity[8] and provided 45.5 percent of Ontario's energy requirements in 2010.[9] They provide baseload capacity with the exception of the Sir Adam Beck Pump Generating Station (PGS). The condition and performance of these assets, including the role that they serve in Ontario's market, is discussed in Chapter 2.2.

OPG also owns the Bruce A and B nuclear power stations which are leased to Bruce Power, L.P. Recovery of net lease costs by OPG is reflected as an offset when calculating the payment amounts for the prescribed nuclear facilities.[10]

1.3 Objectives and Approach

The objective of this report is to provide the foundation for an efficient and effective review of potential IRM approaches, providing the Board and other stakeholders with a framework for analysis purposes, the identification of specific options, and an assessment of these options against a set of criteria that reflect Ontario's circumstances. We anticipate that stakeholders will use this report as a starting point, suggesting additions (and deletions) from the list of options, proposing additional criteria to be considered when assessing various options, and perhaps reaching alternative conclusions when applying these criteria.

This report leverages prior discussions of IRM as applied to OPG's prescribed generation facilities, including documents that were prepared by the Board and other parties to EB-2006-0064, the generic review of potential price-setting methodologies. An effort has been made to incorporate proposed options raised by participants in that proceeding, but without attribution. In addition, certain IRM concepts, including performance benchmarking and an incentive for hydroelectric production, have been introduced in the two subsequent CoS proceedings, EB-2007-0905 and EB-2010-0008. A summary of the 3rd Generation Incentive Regulation (3rd Generation IR) as applied to Ontario's electricity distributors is included for context as a price cap approach is one of the options that merit consideration and because the review of IRM for OPG's prescribed facilities is likely to involve many of these same stakeholders.[11] Power Advisory has researched efforts in other jurisdictions to apply IRM mechanisms to generation facilities that continue to be subject to regulation. Due to restructuring of electricity markets, much of this prior, albeit limited, experience dates back to the 1980s and 1990s.

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8 As reported on the IESO website, indicating that Ontario has 34,960 MW of installed generation capacity as of August 2, 2011. This total includes 11,446 MW of nuclear and 7,957 MW of hydroelectric capacity.

9 Ontario's total energy demand in 2010 was 142.1 TWh.

10 As provided for in Sections 6(2)9 and 6(2)10 of O. Reg. 53/05.

11 3rd Generation IR is applied throughout the Ontario electric distribution sector. Two large natural gas distributors, Enbridge Gas Distribution and Union Gas Limited, have IRM plans in place. The Board is conducting an assessment of IRM applied to natural gas distributors in EB-2011-0052.

1.4 Contents of This Report

Following this Introduction, the balance of the Report is presented in five additional chapters. Chapter 2 provides background information, including a brief description of relevant Board proceedings since O. Reg. 53/05 was made and a discussion of the operational performance of OPG's prescribed generation facilities over the past few years. Chapter 3 presents a discussion of IRM concepts, applications and challenges both in a general context and as applied to generation operations. Chapters 4 and 5 present specific options for OPG's regulated nuclear and hydroelectric operations, respectively, and assess these options against relevant evaluation criteria. Finally, our principal conclusions and recommendations are presented in Chapter 6.

2. Regulation and Operation of OPG's Prescribed Generation Facilities

Chapter 2 provides a brief overview of the regulation of OPG's prescribed generation facilities as established by statute and through subsequent Board precedent. This precedent includes a generic policy proceeding (EB-2006-0064) that assessed alternative methodologies for establishing a regulated price for these assets, and two subsequent proceedings that set payment amounts based on a CoS methodology. It also provides background information on the prescribed facilities including their recent performance, present condition, and any particular cost or efficiency issues that might be addressed by IRM.

2.1 Statutory Guidance, Agreements, and Regulatory Precedent

The *Energy Competition Act, 1998 (ECA)* set in motion the creation of the Ontario electricity market and established OPG by separating out the generation assets formerly owned by Ontario Hydro.[12] This section reviews the establishment of the class of OPG generation assets that is referred to as the "prescribed generation facilities" and the pricing of output from these facilities.

2.1.1 O. Reg. 53/05

The new electricity market opened on April 1, 2002 and OPG's generation assets bid into this market with compensation that was subject to the Market Power Mitigation Agreement (MPMA), under which OPG received the spot market price for its production and was required to rebate to Ontario consumers the difference between the spot price and 3.8 cents/kWh.[13]

This pricing methodology for OPG's generation remained in place until April 1, 2005, the effective date of O. Reg. 53/05 and the termination of the MPMA rebate mechanism.[14] This new regulation established the "prescribed generation facilities" and set initial prices of \$49.50/MWh for production from the nuclear prescribed generation facilities and \$33.00/MWh for hydroelectric production up to 1,900 MWh per hour. OPG was compensated for hydroelectric production in excess of this level at the market price. This arrangement operated much like a "contract for differences" as the difference between these fixed contract prices and the Hourly Ontario Energy Price (HOEP) was credited to customers through the Global Adjustment (GA).

[12] A discussion of the evolution of the Ontario electricity market and relevant regulatory oversight can be found at: http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Legislation/History+of+the+OEB

[13] The MPMA was also based on the anticipated output of OPG's units, which established the weights that were used to calculate the annual average price from which the rebate amount was calculated.

[14] In May 2003 the rebate received by Ontario consumers was based on the Business Protection Plan Rebate, after the introduction of Bill 210, the *Electricity Pricing, Conservation and Supply Act, 2002*.

Under O. Reg. 53/05, this pricing structure was to remain in place for at least three years and until such time as the OEB could determine and apply an appropriate methodology for setting payment amounts. The Board was provided with wide discretion as to "the form, methodology, assumptions and calculations used in making an order that determines payment amounts." However, this discretion was not unlimited. The regulation established certain variance and deferral accounts and required that the Board ensure recovery of the balances in these accounts as long as certain conditions were met. These accounts had the effect of excluding certain cost categories from the application of whatever methodology would eventually be adopted by the Board. Certain of these accounts remain in place today and will need to be incorporated into the design of an IRM. For example, the regulation as amended in 2008 provides for the recovery of costs of activities that are not related at all to the prescribed generation facilities, including non-capital costs for the planning and development of proposed new nuclear generation facilities. Further discussion of OPG variance and deferral accounts is presented in Chapter 2.1.4.

Along with the enactment of O. Reg. 53/05, the Province of Ontario entered into a Memorandum of Agreement (MOA) with OPG dated August 17, 2005. This MOA established OPG's mandate with respect to all of its assets, including the prescribed generation facilities. The first three of eight mandates are particularly relevant with respect to consideration of IRM:

- OPG is obligated to operate its existing generation facilities as efficiently and cost-effectively as possible (the first mandate);
- OPG is obligated to reduce its exposure to risk from its investments in nuclear generation, citing refurbishment of older units in particular, and is expected to operate with a high degree of vigilance when it comes to safety of its nuclear fleet (the second mandate); and
- OPG is obligated to seek continuous improvement in its nuclear generation business and its internal services (the third mandate).[15]

The MOA also imposes a specific obligation on OPG with respect to the third mandate:

> OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.[16]

The MOA required OPG to establish three-to-five year performance targets that were based on the benchmarking of its performance against the North American units. Other relevant aspects of the MOA included an obligation for OPG to operate with a high degree of

[15] Memorandum of Agreement between Her Majesty the Crown In Right of Ontario (the "Shareholder") and Ontario Power Generation ("OPG") dated August 17, 2005, page 1.
[16] Ibid., page 1.

accountability and transparency and to operate on a financially sustainable basis, implying an obligation to husband the value of its generation assets and thereby protect its shareholder's (the Province of Ontario) interest.

By enacting O. Reg. 53/05 and subsequently entering into this MOA, the Province took meaningful steps toward an incentive regulation approach by: (1) establishing market-based pricing for hydroelectric output exceeding a benchmark level, (2) establishing an expectation that OPG would seek operational efficiencies, and (3) by requiring OPG to benchmark its nuclear performance against other CANDU and North American nuclear units.

Section 1 of the *Ontario Energy Board Act, 1998* also includes two objectives that are particularly relevant for purposes of setting prices for OPG's prescribed generation facilities:

(1) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electric service; and,

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

2.1.2 Policy Review and Subsequent Payment Setting Proceedings

In order to prepare to assume its new payment-setting responsibilities, the OEB opened a policy consultation docket (EB-2006-0064) to examine and consider alternative approaches to setting payment amounts for OPG's prescribed generation facilities. A consultant report explored three primary methodologies for setting payment amounts for regulated generating assets: CoS, IRM, and "Regulation by Contract".[17] Regulation by Contract represents a negotiated long-term pricing agreement between the regulated entity (in this case, OPG) and an entity authorized to negotiate on behalf of the provincial interests.

Following the consultation, the Board determined that IRM was the best approach to adopt in the long-term, but that it was appropriate to transition to this methodology by setting payment amounts based on CoS at the outset, providing an opportunity for the Board and stakeholders to become more familiar with OPG's costs before adopting an IRM framework. This is a logical first step because it is generally agreed that IRM benefits from the establishment of a price based on CoS principles as the initial value or "cast-off" point. The potential burden on intervenors that were unfamiliar with OPG's costs was a contributing factor in a decision to stage the review of OPG's costs over at least two initial CoS proceedings. The Board also recognized that some IRM frameworks require special studies such as productivity and inflation studies, to be performed before IRM can be implemented. These studies can be complex and take time to prepare.

[17] "Alternatives for regulating prices associated with output from designated generation assets", prepared by London Economics International, LLC., dated May 19, 2006.

In reaching its conclusion that IRM is the best approach in the long-term, the Board refined its notion of potential efficiency gains that it hoped to encourage by adopting IRM:

> "Efficiency can be defined in a number of ways. The Board's key focus in this regard is to encourage productivity gains that are enduring and for the benefit of both the regulated company and the consumer. This means that regulated companies have incentives to manage costs while maintaining or improving their service levels."[18]

The two initial payment reviews provided an opportunity for the Board and other stakeholders to become familiar with OPG's costs. The payment amounts established by these two reviews are presented in Table 1.

Table 1: Historical OPG Payment Amounts (Excluding Deferral and Variance Account Recovery)

Methodology	Effective Date	Nuclear Payment ($/MWh)	Hydroelectric Payment ($/MWh)
ECA + MPMA (Prescribed)	May 1 2002	$38.00	$38.00
O. Reg. 53/05 (Prescribed)	April 1 2005	$49.50	$33.00 up to 1900 MWh per hour; market price above 1900 MWh per hour
EB-2007-0905 (Cost-of-Service)	April 1 2008	$52.98	$36.66 with HIM
EB-2010-0008 (Cost-of-Service)	March 1 2011	$51.52	$35.78 with modified HIM to reflect sharing above a cap

The first CoS proceeding was EB-2007-0905, with the Board establishing new payment amounts that became effective April 1, 2008. This review focused on OPG's cost of capital, including the appropriate equity ratio and return on equity, nuclear O&M expenses, revenues from other activities including Bruce lease revenues, recovery of variance and deferral account balances and the appropriate level of mitigation in response to weak economic conditions. The Board rejected a proposal by OPG to implement a two-part fixed and variable rate design for its nuclear operations. Benchmarking of OPG's nuclear facilities received considerable attention during the proceeding. The Board also approved OPG's proposed HIM that provides OPG with an incentive to increase production above the monthly average production level in hours where the Ontario market-clearing price exceeds the regulated payment amount.

[18] November 30, 2006 Board Report, "*A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation, Inc.*", page 5.

The second CoS proceeding was EB-2010-0008, with the Board establishing new prices that became effective March 1, 2011. There was considerable discussion in this proceeding related to the HIM and its relationship to the existence of surplus baseload generation (SBG) during certain hours, requiring either the use of the Sir Adam Beck PGS or spilling of water. The Board modified the HIM to provide for equal sharing between customers and OPG above a capped amount. The Board also directed OPG to address the HIM in its next payment filing including, "an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of potential alternative approaches."[19]

2.1.3 Variance and Deferral Accounts

As noted above, O.Reg. 53/05 established several variance and deferral accounts, many of which remain in place today. Variance accounts are commonly used to permit recovery of expense items that are particularly difficult to project, usually because they are impacted by events beyond the control of the utility, such as weather or fuel prices. Deferral accounts allow utilities to track the revenue requirements associated with investments for recovery during a future period. Certain expenses that are not recurring, such as the costs associated with restoration after a major storm, may also be granted deferral treatment and reviewed during the next rate case. Recovery of variance and deferral account balances may be spread over more than one year in response to rate impact concerns.

When O. Reg. 53/05 was initially passed, it established the following five variance accounts to record costs incurred on or after April 1, 2005:

(v1) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(v2) changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes;

(v3) changes to revenues assumed for ancillary services from the generation facilities prescribed under Section 2;

(v4) Acts of God, including severe weather events; and

(v5) transmission outages and transmission restrictions.

The Board is required under O. Reg. 53/05 to permit recovery of prudently incurred expenses recorded in variance accounts over a period not to exceed three years.

The initial regulation also directed OPG to establish a deferral account to track non-capital costs incurred on or after January 1, 2005 that are associated with the return to service of

[19] Decision in EB-2010-0008, Page 146-148.

units at the Pickering A Nuclear Generating Station and directed the Board to ensure recovery of these costs over a period not to exceed fifteen years.

O.Reg 53/05 was subsequently amended to add deferral accounts to provide recovery for: (1) any increase in the nuclear decommissioning liability arising from an approved reference plan under the Ontario Nuclear Funds Agreement (2007); and, (2) non-capital costs for the planning and development of proposed new nuclear generation facilities (2008).

OPG was required to maintain these two? deferral accounts beyond the effective date of the first payment order in EB-2007-0905. In that proceeding, OPG requested and was granted approval to establish a new deferral account for capacity refurbishment costs. OPG was also granted approval to continue the hydroelectric water conditions and ancillary services variance accounts. Finally, OPG requested and received approval to add new variance accounts for nuclear fuel costs and the impact of changes in tax rates, rules and assessments.

Subsequent to its decision in EB-2007-0905, the Board established a variance account for tax losses to align the tax loss amounts experienced by OPG with those amounts that had been reflected in the calculation of rates.[20]

In EB-2009-0174, a proceeding seeking an accounting order related to OPG's variance and deferral accounts, OPG received approval to establish two new variance accounts for the deferral and variance over/under recovery associated with hydroelectric and nuclear operations, respectively.[21] These variance accounts are intended to true-up recovery of other variance amounts approved in the prior payments decision. This is necessary due to the difference between actual and forecast production.

In EB-2010-0008, OPG received approval for continuation of the following accounts:

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

OPG also received approval to close the following accounts once the balances are recovered:

- Interim Period Shortfall (Rider D) Variance Account

[20] Board decision in EB-2009-0038 dated May 11, 2009.

[21] Board decision in EB-2009-0174 dated October 6, 2009.

- Pickering A Return to Service Deferral Account
- Transmission Outages and Restrictions Variance Account
- Interim Period Shortfall (Rider B) Variance Account
- Tax Loss Variance Account
- Nuclear Fuel Cost Variance Account

The Board approved a new variance account as an alternative to reflecting a projection of SBG in the hydroelectric production forecast. The Board concluded that it was difficult to reliably project this impact and that it would be more appropriate to address this uncertainty through establishment of a variance account.[22] In a related matter, and as discussed above, the Board modified the HIM providing for an equal sharing of incentive revenues. This is being accomplished through a new variance account.

Finally, on June 23, 2011, in response to a motion from OPG, the Board agreed to establish variance accounts for pension and "other post employment benefits" costs to record the difference between the forecast reflected in the 2011-2012 test period and actual costs, reversing its initial decision in EB-2010-0008.[23]

As demonstrated by this brief history, the continued appropriateness of existing variance and deferral accounts is reviewed in each proceeding, along with consideration of new accounts. A proposal to adopt an IRM may also require changes to these accounts.

2.2 Costs and Performance of OPG's Prescribed Generation Facilities

2.2.1 OPG's Nuclear Facilities

OPG's fleet of three nuclear plants provides a significant portion of the total electricity in Ontario (32.1% in 2010). Since they operate continuously when they are available, they comprise an even greater percentage of Ontario's total baseload supply capacity. The oldest plant is Pickering A, built as a four-unit plant from 1966 to 1973 with only two units (1 and 4) currently operating.[24] Pickering B, built from 1974 to 1986, has four units, all of which are currently in service. The newest facility is Darlington, a four-unit plant built from 1981 to 1993.[25] All four of the Darlington units are currently operating.

a. <u>Performance</u>

The following table presents summary information regarding the recent performance of OPG's nuclear plants, including the Unit Capability Factor (UCF) for each plant and the weighted average UCF for the entire nuclear fleet.

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[22] OEB, Decision in EB-2010-0008, page 20-23.

[23] OEB, Decision in EB-2011-0090, p. 15.

[24] The four Pickering A units were shut down on December 31, 1997. On August 12, 2005, OPG announced that it would not make the investment necessary to return Units 2 and 3 to service.

[25] International Atomic Energy Agency, Power Reactor Information System.

Table 2: OPG Nuclear Performance

Nuclear Plant Performance Summary					
		Plant			
		Darlington	Pickering A	Pickering B	Totals
Capacity (MW)		3512	1030	2064	6606
Net Generation (TWh)	2010	26.5	5.5	13.7	45.7
	2009	26.0	5.7	15.1	46.8
	2008	28.9	6.4	12.9	46.8
Unit Capability Factor	2010	87.6%	62.4%	76.3%	80.1%
	2009	85.9%	64.2%	84.0%	81.9%
	2008	94.5%	71.8%	71.4%	83.7%

Source: Ontario Power Generation, Annual Information Form for the Year Ended December 31, 2010, dated March 4, 2011, p. 11.

The UCF is a measure of the ability of a plant to produce its potential generation for a specified period and is one indicator of how well a plant is operated and maintained.[26] OPG's 2010 Annual Report attributes the decrease in the Pickering plants' UCFs in 2010 to the Vacuum Building Outage (VBO) scheduled for that year, and the increase in Darlington's UCF to the completion of its VBO in 2009.[27]

The operational performance of OPG's nuclear fleet has been a continual source of concern for the Board. In its 2008 Decision on the first OPG payment case, the Board expressed dissatisfaction with OPG's efforts to update and report on benchmarking data and required OPG to commission and file a benchmarking report from an independent third party.[28] It further directed that this report should undertake the work proposed by Navigant Consulting for Phases 2 and 3 of an initial benchmarking report prepared in 2006:

> "The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant."[29]

The subsequent report, prepared by consultants ScottMadden, Inc. (ScottMadden), was filed with the OEB in EB-2010-0008.[30] This work had two phases. The Phase 1 ScottMadden

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[26] See http://www.iaea.org/cgi-bin/db.page.pl/pris.ucfdef.htm for a more detailed definition of the UCF.

[27] Ontario Power Generation, 2010 Annual Report, p. 29.

[28] Ontario Energy Board, Decision with Reasons, EB-2007-0905, p.29.

[29] Ontario Energy Board, Decision with Reasons, EB-2007-0905, p. 31.

[30] ScottMadden, OPG Nuclear Benchmarking 2009 Report, filed in OEB EB-2010-0008, Ex. F5-1-1. (ScottMadden Report) This report was provided to OPG in July, 2009 and used 2008 data, the most recent then available. The Phase 2 report deals with planning to improve OPG's performance.

report benchmarked OPG against data from the World Association of Nuclear Operators (WANO) and from the Electric Utility Cost Group (EUCG).

The performance of OPG's nuclear facilities against these benchmarks can be summarized as follows: (1) the Pickering A and B plants have among the worst, and on some measures the worst, operating records among the plants in the WANO and EUCG data bases, as detailed more specifically below; and, (2) Darlington operates consistently above the median in the benchmarking comparisons and on some measures is in the top quartile. However, as a result of the very poor performance of the Pickering plants, OPG as an operator also ranks among the worst, as shown on the three key indicators in the ScottMadden report.

The ScottMadden report benchmarked OPG against 19 performance indicators, which they placed in three categories:

- Safety;
- Reliability; and
- Value for Money.

The ScottMadden report noted that, "[o]verall, OPG's performance in the WANO NPI safety metrics is strong" with mixed results on Collective Radiation Exposure.[31] Further, the Board expressed no concerns about OPG's safety performance in its Decision for EB-2010-0008.

The report highlighted 3 of the 19 (one overall, one reliability and one value for money) as key indicators, with the following results for OPG based on 2008 data: [32]

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

Table 3 summarizes OPG's performance on some key indicators at the individual plant level. The table uses data from the ScottMadden report and applies a color-coded scheme to indicate which quartile of the comparator group the plant falls into.

Darlington's performance is better than the median on all of these indices except non-fuel operating costs. The performance of both Pickering plants, on the other hand, is well below the median on all of these indices except for fuel costs. All six of the operating Pickering

[31] ScottMadden Report, p. 9.

[32] ScottMadden Report, p.135, 137. 138. The comparison group for the first two indicators is the WANO's group of North American nuclear fleet operators for both Pressurized Water Reactors (PWR) and Pressurized Heavy Water Reactors (PHWR), which includes the Candu plants. The comparison group for Total Generating Cost per MWh is a group of nuclear owners reporting costs to the EUCG.

units are among the bottom 10 on the overall WANO NPI (out of the 87 PWR and PHWR reactors operating in North America). The WANO NPI is an index that measures overall operating performance.

Table 3: OPG Nuclear Plant Performance Against Benchmarks

	Top Quartile	Median	Pickering A	Pickering B	Darlington
Reliability					
WANO NPI (Index)	96.19	62.46	60.84	60.93	95.67
2-Year Forced Loss Rate (%)	0.68	3.79	37.9	18.19	0.93
2-Year Unit Capability Factor (%)	90.97	84.31	56.6	73.17	91.99
Value for Money					
3-Year Total Generating Costs per MWh ($/Net MWh)	$ 28.66	$ 32.31	$ 92.27	$ 58.68	$ 30.08
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)	$ 18.06	$ 21.28	$ 82.62	$ 50.95	$ 25.10
3-year Fuel Costs per MWh ($/Net MWh)	$ 5.02	$ 5.37	$ 2.64	$ 2.68	$ 2.62

Code: Green = top quartile
White = second quartile
Yellow = third quartile
Red = bottom quartile
Source: ScottMadden, op. cit., p. 5

On certain of the 19 indices in the ScottMadden report, including some key indicators, the Pickering units are not only the worst performers in North America, they achieve this distinction by a wide margin. For example, Pickering A1, B7 and A4 all have forced loss rates (FLR) over 30%; no other North American PWR or PHWR unit has an FLR over 20%. By way of contrast, the median FLR for all units is 1.69% and the top quartile have FLRs of under 0.74%. The FLR is defined as the annual percentage of energy generation that a plant is not capable of producing because of an unplanned shutdown or load reduction. It is an indicator of how well important equipment is maintained and operated. The Pickering A1 unit's FLR was over 43%.[33] All of the Pickering units are in the bottom ten in North America on FLR. A similar comparison holds when benchmarked against CANDU units only.[34]

[33] ScottMadden, op. cit, p. 84.

[34] ScottMadden, op. cit., p. 78. The median for CANDU units was 3.31%, and the top quartile had FLR of under 0.71%,

The ScottMadden report quantifies the causes for the gaps between the OPG plant performance and the best quartile among the CANDU benchmark group. It attributes problems to one of three categories:

- Equipment Reliability: Failure of component or equipment that directly forced or extended an outage (includes material condition problems);

- Design Basis: Equipment operated as per design but an inadequate design margin directly forced or extended an outage; and

- Human Performance (HP): Event caused by HP issues that directly forced or extended an outage, but HP event had to be in recent past (i.e. no HP on design basis errors in the past). This included contractors inside or outside plant (i.e. Water Treatment) that directly impacted plant operations.[35]

It is important to note that performance in two of these three categories (Equipment Reliability and Human Performance) can be influenced by operator decisions and actions.

For Darlington, the gap on FLR is 0.25%. ScottMadden attributes most (83%) of that gap to equipment reliability, 11% to material condition and 6% to human performance.[36] The gap for Pickering A to the best quartile in the CANDU group was 37.2%. ScottMadden attributes 42% to equipment reliability, 51% to design basis, and 7% to human performance. The Pickering B gap was 17.5%, with, 75% attributed to equipment reliability, 5% to design basis, and 20% due to human performance.[37]

On total generating cost per MWh, another key measure, an OPG plant (Pickering A) is the worst among the 55 plants in the EUCG sample, with a cost of over $90 per MWh; no other plant has a cost per MWh over $70. Pickering B ranks 51st out of 55.[38] Darlington is above the median in the middle of the second quartile. The ScottMadden report notes that all of the OPG plants perform well on fuel cost/MWh. However, this is an advantage of the CANDU technology.[39]

The ScottMadden report attributes Darlington's non-fuel cost performance to CANDU technology, corporate allocations, and potentially controllable costs; Darlington's size, with four large units, helps to restrain these costs although Darlington is still in the third quartile among the comparison group. For both Pickering A and B, the ScottMadden report says that the most important driver of high cost is the UCF. For both plants, small size also

[35] ScottMadden, op. cit., p. 80. Design basis problems are not in OPG's current control; by definition, they occur when the plant is being operated properly according to its design. Equipment reliability problems may be due to faulty equipment or to poor material condition. Human performance problems arise from the management and operation of the plant by OPG.

[36] ScottMadden, op. cit., p. 81.

[37] ScottMadden, op. cit., p. 81.

[38] ScottMadden, op. cit., p. 118.

[39] ScottMadden, op. cit., p. 120.

contributes to higher cost. Their cost is also attributable to the same three factors as affect Darlington: CANDU technology, corporate allocations, and potential controllable costs.[40]

The ScottMadden report used the most recent data available, through 2008. To update these comparisons, Power Advisory examined nuclear operating plant data (Energy Availability Factor) from the International Atomic Energy Agency.[41] The data are used for two analyses: the direction of change of the OPG plants' performance since 2008, and a comparison of their direction of change and level of performance with Bruce Power's plants. This comparison does not reflect a comprehensive benchmark effort such as the ScottMadden study and can therefore be considered only indicative. It uses a slightly different measure from that in the ScottMadden report and the results cannot be directly compared, but the 2008 two-year average observations are close to the two-year unit capability factor (UCF) in that report.

Table 4: Energy Availability Factors

Two Years Ending	Energy Availability Factor (%) Two-year average Plant averages			
	Bruce B	Darlington	Pickering A	Pickering B
2006	86.3%	88.8%	76.6%	75.7%
2008	88.4%	91.1%	56.2%	72.2%
2010	91.3%	85.8%	62.7%	79.4%

Data Source: IAEA, Power Reactor Information System

The table indicates that the performance of the Bruce B plant consistently improved over this six-year period. Not all units improved uniformly, but the Energy Availability Factor increased by 2-3% in each of the periods shown. Performance at OPG's Darlington plant was not consistent. Its performance improved from 2006 to 2008, the period covered by the ScottMadden report, and they reported that the Darlington plant's performance was steady.[42] However, Darlington's Energy Availability Factor performance fell in the next two-year period according to the IAEA data. This was at least in part due to the VBO at Darlington in 2009,[43] but the plant average Energy Availability Factor rose by only about 1.5% in 2010 while the 2-year deterioration was over 6%. In examining the Pickering A data, it should be noted that the two units (1 and 4) at this plant had just returned to service in 2005, and that 2005 data is reflected in these statistics. Pickering had a VBO in 2010.[44] Pickering A's

[40] ScottMadden, op. cit., p. 121

[41] IAEA, Power Reactor Information System (PRIS), www.iaea.or.at/programmes/a2/, The IAEA PRIS provides plant-level data on "Energy Availability Factor", which differs from UCF only by including external losses not under plant management control. It is therefore close to, but not identical with, UCF.

[42] ScottMadden, op. cit., p. 5.

[43] Ontario Power Generation, 2010 Annual Report, p. 14.

[44] Ibid.

performance in its first year back was good, but it fell from that level in the two years to 2008 and recovered in the two years to 2010. The fall in 2008 is consistent with the ScottMadden report. Pickering B, on the other hand, deteriorated in the two years to 2008 but improved in 2010 to a level well above that experienced in 2005-2006. The ScottMadden report said that Pickering B's UCF performance was roughly constant from 2006 to 2008.

These data indicate that Darlington's performance has deteriorated since the ScottMadden report, while both of the Pickering plants have shown a significant 6-7% increase in their Energy Availability Factor.

OPG acknowledges that the performance of the Pickering plants has been poor. In its submission to the OEB for EB-2010-2008, OPG asserted that there are essential characteristics of CANDU nuclear plants that make them more expensive.[45] They list complexity, generation technology (the fact that OPG owns the first large-scale CANDU reactors), safety and regulation, training, high standards for materials, and the radioactive work environment as the drivers of high costs. However, many of these drivers apply to all nuclear generation plants, so they do not explain the large gaps between OPG performance and the top quartile in the ScottMadden benchmarking study.

One inherent characteristic that can account for the higher cost of the Pickering plants is size. The ScottMadden report explains that there are economies in having more than one unit on a site, while there are diseconomies of unit size. The Pickering plants have among the smallest unit sizes in North America, while they have the advantage of having four units at the Pickering B site and two at Pickering A. OPG recognizes that the poor material condition of these plants contributes to their poorer performance and higher operating costs.[46]

The conclusion from this analysis of the performance of the OPG nuclear fleet is that its performance does not match the benchmark. Further, at least with performance shortcomings that are attributable to "Equipment Reliability" and "Human Performance", there appear to be actions that can be taken by OPG to improve performance relative to the benchmark data. Ideally, an IRM should incent OPG to improve its operation and bring it closer to a high industry standard as represented by the highest quartile in the ScottMadden report.

In Phase 2 of the ScottMadden project, OPG worked with ScottMadden to develop a gap-based top-down business plan for performance improvement aimed at making such improvements in OPG's operation of its nuclear fleet. The plan identifies a target level for

[45] OPG, "Key Drivers of Total Generating Costs", EB-2010-0008. Ex. F2-1-1 Attachment 3

[46] For example, at p. 9 of EB-2010-0008, Ex. F2-1-1, OPG says that poor material condition leads to higher FLR. At p. 13 of EB-2010-0008, Ex. F2-1-1, it says that its low targets for reduction in total generation costs relate to the initial material condition of the plants.

each of the 19 performance indicators in the ScottMadden report.[47] This is discussed further in Chapter 4 that addresses the design of an IRM for OPG's nuclear fleet.

b. Cost Structure and Capital Additions

Total Operations, Maintenance and Administration (OM&A) actual, budget and planned expenses are shown in Table 5. Base OM&A is roughly constant at about $1.2 billion, with outage OM&A at about $130-140 million.[48] The overall budget is also flat at about $2 billion over this period.

Table 5: Nuclear OM&A Summary

Nuclear OM&A Summary	2008 Actual	2009 Actual	2010 Budget ($million)	2011 Plan	2012 Plan
Base OM&A	$1,252	$1,217	$1,187	$1,192	$1,220
Project OM&A	$137	$144	$144	$136	$132
Outage OM&A	$196	$255	$285	$215	$201
Generation Development OM&A	$34	$80	$41	$6	$5
Allocation of Corporate Costs	$238	$235	$247	$249	$252
Allocation of Centrally Held Costs	$132	$59	$171	$199	$234
Asset Service Fee	$29	$27	$25	$24	$24
Total OM&A	$2,018	$2,015	$2,099	$2,021	$2,068

Source: OEB Decision with Reasons, EB-2010-0008, p. 46.

The total OM&A budget for nuclear operation in the approved 2009-2013 Nuclear Business Plan was about $1.6 billion for 2011 and 2012, rising to about $1.8 billion for 2013.[49] However, in the 2010-2014 Nuclear Business Plan, these amounts are reduced by about $100 million per year, leaving the OM&A operations budgets at about $1.5 billion for 2011 and 2012, rising to about $1.6 billion for 2013.[50] The reductions include lower base and outage expenditures, savings relating to lower labour rates and lower labour burden rates, plus specific savings related to Inspection Maintenance and Commercial Services reducing the amount of service provided by OPG to Bruce Power.

Within these numbers, the OM&A expenditures for Pickering decline while those for Darlington increase. The base OM&A for Pickering A falls from $204 million in 2009 to a

[47] Ontario Power Generation, Nuclear Operations 2010-2014 Business Plan, filed in EB-2010-0008. Ex. F2-1-1, Attachment 1, p. 5.

[48] Base OM&A covers all of the activities to operate the plants to produce electricity, including all actions to deal with forced outages. Outage OM&A is the incremental expense for planned outages, primarily the cost of temporary staff including experts from original equipment suppliers as needed for inspections and specialized services. Project OM&A are expenditures for non-recurring large projects, like some of the expenditures for Pickering B life extension. EB-2010-2008-0008, Ex. F2-4-1, p. 1.

[49] These operating amounts do not include the allocated common and central costs shown in the table.

[50] OPG, 2010-2014 Nuclear Business Plan, EB-2010-2008, Ex. F2-1-1, Attachment 1, p. 16.

planned $145 million in 2012 and that for Pickering B falls from $278 million in 2009 to $226 million in 2012, a total drop of about $110 million. The increase for Darlington is smaller than that, at about $15 million; expenditures rise from $301 million in 2009 to $316 million in 2012.

The base OM&A budget includes the OM&A part of the Pickering B Continued Operations project with estimated expenditures of approximately about $18 million in 2011 and $15 million in 2012.[51] These expenditures are necessary to extend the life of Pickering B in order to keep it operating during the Darlington Refurbishment Project. The project is not anticipated to require an extended shutdown of any Pickering B unit.

Allocated costs (Corporate Costs and Centrally Held Costs) make up about a quarter of the total nuclear OM&A costs. Corporate Costs include real estate, energy markets, business services, IT, finance, corporate and executive services (including regulatory, strategic planning, law, and public affairs) and human resources. Centrally Held Costs include other post employment benefits (not related to current employees), insurance, performance incentives, IESO non-energy charges and some other costs and credits. In EB-2010-2008, OPG filed a Black and Veatch report which stated that OPG's allocation methods for both Corporate Costs and Centrally Held Costs are in accordance with current best practice.[52] Board staff questioned the amount of regulatory costs, but the Board did not adjust these expenditures.[53]

Subject to correction of a double-counting error and an adjustment to compensation levels, the Board accepted OPG's proposed OM&A expenditures. The Board expressed concerns with the analysis related to the Pickering B Continued Operations Project.[54] Board staff asserted that the UCF used in the analysis was overstated and the price used for comparative purposes was not the appropriate one.[55] The Board suggested that OPG could seek an independent view on some of these issues from the OPA for its next filing.

OPG Nuclear takes a portfolio approach to capital projects. Some capital, such as minor fixed assets and the Pickering 2 and 3 isolation projects, are outside the portfolio. Portfolio projects must meet certain criteria (cost threshold, limited duration, incremental impact, and accountability) and can be classified as either capital or OM&A. The table below summarizes the nuclear capital expenditures with historical values, 2010 budget and 2011/12 plans.

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[51] EB-2010-0008, Ex. F2-2-3, p. 10, Chart 2. Total cost of Pickering B life extension is about $195 million including expenditures in Base, Outage and Project OM&A. EB-2010-0008, F2-2-3, Attachment 1, p. 1.

[52] EB-2010-0008, Decision with Reasons, p. 93.

[53] EB-2010-0008, Decision with Reasons, p. 94.

[54] EB-2010-0008, Decision with Reasons, p. 52

[55] EB-2010-0008, Decision with Reasons, p. 52

No intervenors commented on the operations capital expenditures. They did comment on the DRP expenditures. The Board accepted the proposed expenditures.[56]

Table 6: Summary of Nuclear Capital

Nuclear Capital Summary	2008 Actual	2009 Actual	2010 Budget ($million)	2011 Plan	2012 Plan
Portfolio	$164	$159	$172	$172	$172
P2/3 Isolation	$6	$14	$9	$0	$0
Minor Fixed Assets	$14	$17	$20	$20	$20
Total Operations Capital	$183	$191	$201	$192	$192
Generation Development (DRP)	$0	$1	$73	$105	$256

Source: Decision with Reasons, EB-2010-0008, pg. 55

c. Darlington Refurbishment Project

The most important capital project being planned by OPG Nuclear is the Darlington Refurbishment Project (DRP) for the four reactors at Darlington. The project requires shutting each of the reactors down in sequence, in order to complete a refurbishment that is required of all CANDU reactors near mid-life. The project is expected to extend the reactor life by 30 years, to 2055.[57]

Planning is underway and includes expenditures from 2010. The project is projected to have a cost in the range of $6-10 billion. The Board has expressed concern about the ability of OPG to keep its costs within that range.[58] In its Decision with Reasons for EB-2010-0008, the Board notes that no CANDU refurbishment project has been completed within its original budget.[59] A "release quality estimate" of costs is expected in mid-2014.[60] The Board expects that OPG's Board of Directors will use the better-defined cost data to consider whether it still wants to proceed with the DRP, the cost-effectiveness of which was questioned in EB-2010-0008.[61] The first unit is expected to come out of service in the third quarter of 2015.[62]

The Board also considered whether expenditures on Darlington refurbishment qualify for the variance accounting treatment under O.Reg 53/05. In the Board's opinion, they would

[56] EB-2010-0008, Decision with Reasons, p. 59.

[57] OPG, Project Description, Darlington Nuclear Generating Station Refurbishment and Continued Operation Project Environmental Assessment. Submitted to: Canadian Nuclear Safety Commission April, 2011. NK38-REP-07730-10001, Table 2.2, p. 19

[58] OEB, Decision with Reasons, EB-2010-0008, p. 72.

[59] OEB, Decision with Reasons, EB-2010-0008, p. 73.

[60] OEB, Decision with Reasons, EB-2010-0008, p. 73

[61] OEB, Decision with Reasons, EB-2010-0008, p. 72

[62] OPG, Project Description, Darlington Nuclear Generating Station Refurbishment and Continued Operation Project Environmental Assessment, p. 19.

qualify.[63] The Board rejected OPG's request to include its preparatory expenditures on DRP in the rate base under Construction Work in Progress. The Board approved OM&A expenditures of $5.9 million in 2011 and $4.5 million in 2012 for DRP planning.[64]

As discussed in Chapter 4, the DRP must be reflected in an IRM design as production from the plant will be significantly lower during the unit shutdowns.

d. Staffing and Compensation Levels

Staff costs are a very large fraction of OPG Nuclear's total OM&A costs. The Board has expressed concern about both the number of staff and their level of compensation.[65]

Phase 2 of the ScottMadden report presented benchmark information on staffing levels. The data are from the EUCG group. To make comparisons, ScottMadden normalized the data to account for the number of units.[66] The data are shown in Table 7 and are the totals for all staff, on-site and off-site. All of the OPG plants have total staffing levels above the mean of the median. For some activities, they are close to the lowest quartile, while other activities are well above this quartile. In the case of Pickering A, the normalized staff levels are affected by the fact that the plant only has two working reactors, yet was designed for four.

Table 7: Comparison of Total Staffing Levels

Functional Area	Mean of Lowest Quartile	Mean of Median	Pickering A	Pickering B	Darlington
	(Staff count per unit)				
Configuration Management	23.7	36.6	72.3	61.8	55.1
Equipment Reliability	29.7	40.5	101.9	69.2	74.2
Loss Prevention	23.5	32.1	24.2	34.5	33.5
Materials and Services	14.6	21.7	40.9	41.2	40.2
Nuclear Fuel	4.9	8.5	12.5	12	10
Operate Plant	118.6	133.4	261.6	182.4	205.9
Management and Support	37.7	56.5	131.3	114.1	117.6
Training	22.2	31.7	15.9	25.9	26.2
Work Management	127.6	147.2	290.4	197.9	205.9
Total	**403.5**	**508.3**	**962**	**738.8**	**768.3**

Data source: ScottMadden report, Phase 2, p. 58

63 OEB, Decision with Reasons, EB-2010-0008, p. 70

64 OEB, Decision with Reasons, EB-2010-0008, p. 72. Proposed amounts on p. 66.

65 Decision with Reasons, EB-2010-0008, p. 84.

66 That is, the staff numbers were divided by the number of units. So the data in the table are staff per unit for each activity. ScottMadden, "Nuclear 2009 Benchmarking Report, Phase 2 Final Report", filed in EB-2010-0008, Ex. F5-1-2, Appendix G, p. 58

The data also contain direct comparison with staffing levels at Bruce Power, but these were redacted in the report for confidentiality purposes.[67] ScottMadden says that OPG's staffing levels are clearly well above the benchmarks of the top quartile and the median.

ScottMadden concludes that these data indicate that OPG maintains a higher level of staff at its plants than do other North American nuclear operators. The table indicates the greatest discrepancies are in the areas of plant operation and support management, which are also the functional areas with the highest staffing levels.[68]

In its Decision with Reasons for EB-2010-0008, the Board noted that OPG's mode of presenting staffing data makes comparisons difficult;[69] but that it is clear from the ScottMadden Report that OPG staffing levels generally exceed the median for its comparator group. The Board expressed the view that OPG could decrease the number of employees further to reduce costs and improve productivity,[70] but that, given collective agreements, adjusting staffing levels may take time while anticipated retirements should create future opportunities for staff reductions.[71] At the same time, the Board, inferring from OPG's response to the one worked-out example of staffing analysis from ScottMadden, implicitly questioned OPG management's dedication to the implementation of staff reductions.[72]

On the issue of compensation, the Board found that an appropriate benchmark for OPG staff would be the 50th percentile of the comparator groups. OPG argued in favor of continuing to use a 75th percentile, but the Board rejected that argument, noting that OPG uses the 50th percentile for its management staff.[73] OPG had data from a Towers Perrin study and filed that study in a confidential transcript undertaking. The Board concluded that compensation for some of OPG's staff is excessive relative to comparable market levels.[74] Consequently, the Board reduced OPG's revenue requirement by $55 million for 2011 and a further $35 million (to a total of $90 million) in 2012 to represent a move of staff compensation levels towards the 50th percentile.[75]

[67] ScottMadden, Phase 2 report, p. 24.
[68] Ibid, p. 25.
[69] OEB, Decision with Reasons, EB-2010-0008, p. 84
[70] OEB, Decision with Reasons, EB-2010-0008, p. 85
[71] Ibid.
[72] Ibid.
[73] Ibid.
[74] Ibid., p. 86,
[75] On February 14, 2012, the Ontario Superior Court of Justice upheld this Board order after rejecting an appeal by OPG, the Power Workers Union, and the Society of Energy Professionals. Ontario Power Generation v Ontario (Energy Board), 2012 ONSC 729, Files 184/11, 180/11, 194/11.

2.2.2 OPG's Hydroelectric Facilities

OPG's prescribed hydroelectric facilities serve multiple purposes. Most importantly, they are low-cost renewable energy resources that contribute to the reliability of Ontario's electricity system. The pumped storage facility at Sir Adam Beck helps restrain the Hourly Ontario Energy Prices (HOEP) when demand is greatest. To the extent that OPG's hydroelectric (and nuclear) facilities produce energy during these hours, the market-clearing price will be lower than it otherwise would have been.

a. Performance

In 2010, OPG's regulated hydroelectric facilities represented approximately 9.5 percent of Ontario's total capacity and 12.5 percent of net electricity generation but their contribution to Ontario's electricity market is more significant than these percentages imply due to their relatively low cost and the ability of the Sir Adam Beck facility to shift loads in a manner that influences hourly prices.

The recent combined performance of OPG's prescribed hydroelectric facilities is presented in the following table.

Table 8

Performance of Prescribed Hydroelectric Facilities 2008 - 2010

	2008	2009	2010
Capacity (MW)	3,332	3,302	3,312
Net Electricity Generation (TWh)	18.3	19.4	18.9
Availability (%)	93.8	93.6	92.8
EFOR (%)	1.5	1.0	0.3

Source: OPG Annual Information Form Year Ended December 31, 2010, page 15.

Each of the six hydroelectric facilities has been operating for at least five decades. As the facilities age, greater capital investment is required to sustain the facilities, although preventative maintenance and periodic replacement of components can often extend the useful lives of hydroelectric facilities for many years. OPG has an asset management program that monitors asset condition and determines the operations and maintenance activities, as well as any capital improvements that are necessary. Based on inspections, components are either replaced prior to failure (when the consequences of failure would be significant) or when they fail. Given the long-term value of these assets, it is critical that they be managed in a way that enhances and preserves this value. In fact, one of the issues raised in EB-2010-0008 was whether or not OPG's capital additions were adequate to achieve this objective. The Board did not find any evidence that reliability was being compromised but reminded OPG of its obligation to demonstrate that its capital additions were sufficient to maintain an adequate level of reliability.[76]

Performance does vary among the six prescribed hydroelectric facilities. The oldest facility is the DeCew Falls 1 station that was placed in service in 1898. This facility is utilized only when there are excess water flows that cannot be accommodated by the newer and more efficient DeCew Falls 2 facility. The performance of the other five facilities is summarized in Table 9.

Table 9

Performance of Prescribed Hydroelectric Facilities
2007 - 2009

	2007	2008	2009
Availability (%)			
DeCew Falls II	77.6	96.9	97.3
Sir Adam Beck I	92.3	92.7	89.1
Sir Adam Beck II	96.9	97.4	96.7
Sir Adam Beck PGS	86.1	79.2	84.5
R. H. Saunders	97.3	95.8	96.7
Aggregate	94.1	93.8	93.6
EFOR (%)			
DeCew Falls II	1.0	0.8	0.2
Sir Adam Beck I	3.7	4.3	2.3
Sir Adam Beck II	0.4	0.2	0.6
Sir Adam Beck PGS	9.7	2.7	4.4
R. H. Saunders	0.0	1.1	0.1
Aggregate	1.8	1.5	1.0
Base OM&A ($M)			
Niagara Plants	38.3	44.6	46.7
R. H. Saunders	40.3	9.4	14.8
Total	78.6	53.9	61.5
Includes Labour ($M):			
Niagara Plants	26.7	28.2	27.8
R. H. Saunders	8.0	8.8	8.8
Total	34.7	37.0	36.6

Notes:
Aggregate value is the capacity weighted average

Source: EB-2010-0008, OPG Exhibit F1 Operating Costs - Hydro

[76] Decision in EB-2010-0008, page 28.

The Sir Adam Beck 1 units are in the midst of a multi-year rehabilitation project that began in 2007. Performance, and in particular the relatively high Equivalent Forced Outage Rate (EFOR), is expected to improve after the rehabilitation project has been completed.

According to OPG, the performance of the Sir Adam Beck PGS reflects the manner in which it is operated. The storage capability of the PGS is used based on the comparative economics of the pump/generate cycle regardless of whether or not SBG is anticipated.[77] As a result, the Sir Adam Beck PGS requires more frequent maintenance activities as it serves multiple roles that require more frequent starts and stops than a conventional hydroelectric facility. In addition to generating electricity on peak and pumping during off-peak periods, Sir Adam Beck PGS provides automatic generation control (AGC) services and is used to divert water. Finally, the pumping capability of the PGS is used to mitigate the potential impact of SBG on Ontario consumers and on the dispatch of nuclear generation facilities.[78]

While maintenance and capital investment actions ensure that the stations maintain high availability factors, the year-to-year electricity market benefits depend in large part on factors that are beyond OPG's control. There are two critical factors in this regard. First, as with most hydroelectric operations, energy production depends on water levels and thus, on annual precipitation (rainfall and snowmelt) and evaporation. The Board's payment-setting policy accounts for the impact of varying water conditions on OPG's revenues through a variance account. In terms of total electricity output figures reported by the IESO, uncommonly low water levels in 2010 resulted in a reduced hydroelectric output of 30.7 TWh, compared to 38.1 TWh in 2009. However, 2011 saw water levels and hydro output rebound to 33.3 TWh.

Second, the IESO has indicated that incidences of SBG may be expected to increase over the next year due to the return to service of Bruce A units, the introduction of the new Bruce to Milton transmission line, and increasing wind capacity.[79] The consequence of SBG is that output from relatively low-cost baseload resources such as nuclear and hydroelectric resources may be restricted when SBG conditions are present. For OPG's hydroelectric facilities, this is accomplished by controlled water spills. Spilling water involves opening sluice gates to direct water to bypass the turbines. It is preferable to store water behind the dam so that it will be available for future production but this is not always possible if the reservoir is full or there is little or no storage capability. However, there are operational limits and consequences associated with the use of hydroelectric facilities to respond to SBG conditions.[80] The operational limits apply both to the generating units that must operate

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[77] EB-2010-0008, OPG Ex. E1-T2-S1

[78] OPG Exhibit F1, Tab 1, page 22 in EB-2010-0008.

[79] IESO Forecast Surplus Baseload Generation Report, posted to IESO's website at: http://www.ieso.ca/imoweb/marketdata/sbg.asp

[80] These are discussed in a November 2, 2011 discussion paper prepared by IESO for Stakeholder Engagement 91, entitled "Dispatch Order for Baseload Generation".

within specified output and water flow ranges and the use of the sluice gates which were not built for frequent opening and closings and do not perform as well during icing conditions. There are public safety concerns as well related to potential downstream impacts of water spills.

The number of hours with SBG conditions depends on the level of demand during off-peak periods and on available capacity and mix of supply resources. The most recent economic slowdown has reduced demand during all hours, and particularly during off-peak hours given the high proportion of industrial demand during such hours. With respect to supply, the addition of variable output resources, particularly wind generation, as encouraged by the *Green Energy and Green Economy Act,* has increased the potential for SBG conditions.

OPG estimates that SBG conditions resulted in a reduction of OPG's hydroelectric generation (from both prescribed and unregulated facilities) by 0.6 TWh in 2009, with a 0.19 TWh reduction for regulated hydroelectric assets.[81] The incidence of SBG events in 2010 was down considerably from 2009, with the exception of April and September 2010 when there were 49 and 37 hours of SBG respectively. According to the most recent IESO *18-Month Outlook*, SBG conditions may be expected to increase in 2012 and 2013 as up to 630 MW of new wind generation is expected to be added through the first quarter of 2013, Bruce nuclear units 1 and 2 return to service (1,500 MW) and the Bruce to Milton transmission line comes into service.[82] Although difficult to project with a reasonable degree of accuracy, these trends indicate that the number of hours of SBG will increase in the short-term, potentially restricting the production of OPG's hydroelectric facilities during SBG periods. Under the current Board payment-setting policies, customers essentially pay for foregone hydrolelectric production that results from water spills as the impact of reduced production is captured through a variance account. To the extent that OPG is completely insulated from the consequences of SBG conditions by variance account entries, this may reduce OPG's incentive to take all possible actions to minimize adverse impacts of SBG conditions. However, the Board has indicated that it will review OPG's operations during SBG conditions and make adjustments to the variance account if it concludes that OPG could have taken additional actions to minimize the potential adverse impact of SBG conditions.[83]

The IESO is currently conducting a stakeholder process, Renewable Integration (SE-91), to address the implications of integrating renewable generation in response to the focus of Ontario's Long Term Energy Plan.[84] The most efficient dispatch response to anticipated SBG conditions is a key topic in this process.

[81] OEB, Decision with Reasons, EB-2010-0008, page 20.

[82] IESO *18-Month Outlook.* Feb. 24, 2012, pg. v. .

[83] Decision in EB-2010-0008, page 147

[84] More information on this process is available at: http://www.ieso.ca/imoweb/consult/consult_se91.asp

b. Cost Structure and Capital Additions

OPG's existing prescribed hydroelectric facilities tend to have relatively high fixed costs and other costs that are beyond OPG's control, at least in the short term. This is demonstrated in Table 10 by the composition of the cost of service in OPG's 2010 rate case. Approximately 86% of OPG's hydroelectric revenue requirements as approved by the Board are represented by the cost of capital, depreciation & amortization and the Gross Revenue Charge (GRC).[85]

O&M costs, which are dominated by fixed costs, represent 17.9% of total revenue requirements.[86] OPG has asserted further that its low operations and maintenance costs are due in part to "significant capital reinvestment, station automation, efficiency improvements, and effective station maintenance."[87]

With respect to O&M costs, all of the Niagara plants are regulated and are operated as a group. It is thus possible to directly assign many O&M costs to this group. The R. H. Saunders station is located on the St. Lawrence Seaway and is maintained as part of the St. Lawrence Plant Group. As it is the only regulated plant among this cohort, many O&M-related costs must be allocated to the R. H. Saunders plant. Also, certain O&M costs are provided in a centralized manner to all of OPG's hydroelectric facilities, including the non-prescribed facilities. These include engineering, dam safety and emergency preparedness, regulatory affairs, and environmental services. These costs are allocated to the regulated hydroelectric business, and then among the regulated stations.

The GRC represents the largest component of expenses. OPG has been paying the GRC since 2001 in accordance with *Ontario Regulation 124/02* under the *Electricity Act, 1998.* The GRC consists of a property tax component and a water rental component. Each of the six prescribed hydroelectric facilities is subject to the property tax component. The water rental component applies to four hydroelectric facilities that are subject to waterpower lease agreements with the Ontario Ministry of Natural Resources or with the Province of Québec for shared use of the Ottawa River.

Although the commercially sensitive data is redacted by the Board in this table, OPG has the ability to generate "other revenues" from several sources. In 2009, OPG generated $42.5 million of other revenues from sales of ancillary services to the IESO, i.e., from providing black start capability, reactive support/voltage control service, automatic generation control, and operating reserve services. The Board reflects an estimate of revenues from ancillary services in the calculation of rates but also captures any difference between this level and actual ancillary revenues in a variance account.

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[85] This percentage is higher if income taxes are included. The Payments Order did not separately identify income taxes.

[86] The sum of these two percentages exceeds 100% because revenue requirements reflect the deduction of revenues from the sale of ancillary services.

[87] Ontario Power Generation, Annual Information Form for the Year Ended December 31, 2010 (2010 Annual Information Form), March 4, 2011, page 15.

Table 10

OPG Hydroelectric Cost of Service 2011 - 2012
(Approved in EB-2010-0008)

	Description	Notes	2011	2012	Total
	Rate Base				
1	Net Fixed Assets		$3,781.3	$3,765.3	N/A
2	Working Capital		0.6	0.6	N/A
3	Cash Working Capital		21.5	21.5	N/A
4	Total Rate Base		$3,803.4	$3,787.4	N/A
	Cost of Capital				
5	Short-Term Debt		$4.7	$6.4	$11.1
6	Long-Term Debt		105.0	104.0	209.0
7	Return on Equity		168.6	170.0	338.6
9	Total Cost of Capital		$278.3	$280.4	$558.7
	Expenses				
10	OM&A		$128.2	$125.9	$254.1
11	Fuel		0.0	0.0	0.0
12	GRC		263.7	263.7	527.4
13	Depreciation & Amortization		65.6	65.0	130.6
14	Property Taxes		0.0	0.0	0.0
15	Total Expenses		$457.5	$454.6	$912.1
	Less:				
16	Ancillary and Other Revenue	1	[redacted]		
17	Income Tax	1	[redacted]		
18	Revenue Requirement		$711.9	$707.2	$1,419.1
	Test Period Forecast Production (TWh)		19.8	19.8	39.7
	Approved Regulated Rate ($/MWh)				$35.78
	Amortization of Variance and Deferral Account Amounts		($27.3)	($32.8)	($60.1)
	Payment Rider ($/MWh)				-$1.65
	Total Rate ($/MWh)				$34.13

Notes:
1 Redacted from Payments Order

OPG also generated $3.6 million from support services provided from the R. H. Saunders plant to Hydro-Quebec and $4.9 million from water transactions with New York Power Authority (NYPA). The Board reflects a three-year rolling average of the Hydro-Quebec and NYPA revenues in the calculation of rates.

Given the economic contribution of OPG's hydroelectric facilities, the ability to increase the amount of capacity and energy produced by these facilities is important if necessary investments can be demonstrated to be cost-effective. OPG added 10 MW of capacity to its Sir Adam Beck I facility in 2010 primarily due to a runner upgrade. More significantly, OPG is in the midst of a multi-year Niagara Tunnel construction project that will increase production from the Sir Adam Beck facilities by approximately 1.6 TWh (a 13.8 % increase).[88] Under the current configuration, water flows are diverted from the Niagara River to the stations by way of a power canal and two tunnels. This third 10.4 km tunnel, estimated to cost $1.6 billion and be placed in service in December 2013, will take advantage of water flows that are available to Canada under treaties with the United States and are not currently used. The project was delayed and budget increased as a result of excavation difficulties that were encountered. The revised schedule and budget include bonus/penalty performance incentives with the contractor related to the target in-service date and budget.[89] There is also a bonus/penalty incentive that will be applied to deviations from the guaranteed flow amount of 500 cubic meters/second.

[88] Percentage increase relative to 30-year average output from the Sir Adam Beck facilities. (Ontario Power Generation, Hydroelectric Business Overview, OPG Regulated Facilities Payment Amounts, March 29, 2010, p. 4.

[89] 2010 Annual Information Form, p. 26.

3. IRM Concepts and Applications

3.1 IRM Objectives

IRM is an alternative to traditional cost-of-service price regulation that is intended to provide the regulated utility with an incentive to operate more efficiently. This incentive typically involves an opportunity for shareholders to earn a higher return on equity than might otherwise be possible under CoS regulation if the utility can manage its costs and growth so as to realize cost savings and productivity gains beyond a base target.[90] Under the most common form of IRM, a price cap regime, initial "cast-off" prices for a base year are established using CoS and then prices are adjusted each year for the term of the plan based on a formula that weakens the link between the costs and prices. Prices are typically recalibrated based on CoS at the end of the term, and the parameters of a subsequent multi-year IRM plan may be also adjusted at that time. The term of an IRM is a key design element as a longer period provides the utility with a greater opportunity to benefit from efficiency gains. A period of sufficient length (e.g., at least three years or longer) is required to provide the utility with a strong incentive to identify, design, and implement efficiency improvements, particularly if significant capital investments or other one-time expenditures may be required to achieve efficiency gains.

Weakening the link between costs and prices in an IRM also creates the potential that the utility will earn significantly more than or less than the authorized return on equity (ROE) reflected in the starting-off prices. This potential may be undesirable to either the utility or the regulator (or both) if the plan design or parameters are off, or if circumstances change mid-plan. There are IRM design elements that can either moderate or cap these impacts. For example, the utility and regulator may agree to share earnings shortfalls or surpluses that fall outside of a "deadband" around the authorized ROE. In addition, IRMs often account for the impact of predefined events that are "exogenous" or outside of the control of the utility and have a significant impact on financial performance. A change in a government tax rate is a common example of an exogenous factor that sometimes merits a price change outside of the IRM formula. The adverse earnings impact of extraordinary circumstances, such as a severe recession, that threaten the financial viability of the utility may also be reflected in the IRM design through the establishment of "off-ramps" that end the IRM before its term is complete.

As discussed in Chapter 3.2, there are two basic types of IRMs: broad-based and targeted incentives. A price cap is an example of a broad-based incentive as it applies to all of the functions of a utility or to a significant subset of clearly defined (and financially measurable) set of activities. In the context of this report that focuses on the generation function, a broad-based IRM may apply to the overall regulated generation business of OPG or to either the hydroelectric or nuclear generation businesses as stand-alone business units. In contrast, a

[90] See Chapter 3.4 for a discussion of incentives to operate efficiently under a CoS regime.

targeted incentive is designed to encourage a specific behavior that the utility has the ability to influence. An incentive to shift hydroelectric production from off-peak to peak hours is an example of such a "targeted" incentive applied to a generation business.

The primary goal of IRM is to provide incentives for the utility to achieve enduring efficiency gains that will benefit customers over the long run. Efficiency gains are enduring or sustainable if they result in a structural change in the way which regulated activities are provided that reduces costs and if prices are reset using CoS principles based on the more efficient cost structure at the end of the IRM term.[91] In this way, the long-term interests of customers and shareholders are better aligned. A parallel objective of many IRMs is to prevent a potential degradation in service quality from overly aggressive pursuit of cost savings. Thus, IRM often incorporates service quality measures and reporting, possibly with a set of financial penalties for underperformance and in some cases, rewards for superior performance.

IRM can result in a change to the allocation of risk between customers and utility owners and care is generally taken to maintain a fair allocation of risks and rewards when designing an IRM. For example, a shift in risk from customers to the utility may be accompanied by a commensurate increase in the opportunity to earn a higher return.

3.2 Broad-Based and Targeted Incentive Mechanisms

As noted above, there are two basic types of IRM mechanisms: (1) broad-based; and, (2) targeted approaches.

Broad-based approaches draw a financial (and accompanying price) boundary around a large group of related business activities. This grouping can represent all or most of the regulated functions of a utility (e.g., transmission, distribution, and generation) or the activities of an entire business unit (e.g., the distribution business).[92] Price caps and revenue cap mechanisms that apply to the distribution function, or transmission and distribution function, of an electric utility are examples of broad-based mechanisms. A price cap sets the maximum amount that the utility may charge for each unit of service or rate design element;[93] a revenue cap sets the maximum revenue requirement to be recovered from rates.[94]

A separate set of financial accounts must be maintained for the group of activities that are being covered by the IRM. Costs associated with functions that are common to this business and other regulated and non-regulated activities must be allocated between activities subject

[91] More efficient in this context may mean that prices increase, but less than they otherwise would have absent IRM-inspired efficiency gains.

[92] It may exclude recovery of costs associated with defined activities whose costs are recovered through distinct rate mechanisms such as a rate rider. Recovery of the costs associated with smart meters are an example of such a mechanism.

[93] e.g., the customer, demand, and volumetric rates for firm service rate classes.

[94] Revenue caps can protect the utility from the impact of declining consumption. Decoupling mechanisms can accomplish a similar objective.

to the IRM and other activities. One significant advantage of a broad-based mechanism is that it provides the utility with considerable flexibility as to how best to design and implement cost efficiency programs, particularly where it is possible to leverage an increase in costs or an investment to achieve overall net savings in other expense categories. Broad-based mechanisms also restrict the ability to "game" the outcome by shifting costs and revenues between activities that are subject to the IRM and those that are not. Earnings sharing mechanisms are another form of broad-based IRM as they are applied to an income statement for an entire business unit. An earnings sharing mechanism provides some protection against earnings that are either unacceptably high (from the perspective of customers and regulators) or unacceptably low (from the perspective of utilities, debt-holders and shareholders). Broad-based approaches are particularly appropriate where the regulator is concerned about the overall level of costs or earnings, but does not particularly care where or how efficiency gains are achieved and has no desire to micro-manage the utility. Because these measures provide strong incentives to reduce costs, they are often accompanied by assurances that the utility must maintain service quality, reliability and safety performance at prescribed levels.

In contrast, targeted IRM approaches tend to focus on a relatively narrow set of activities and are designed to encourage a specific type of behavior with respect to those activities. For example, vertically integrated utilities are sometimes allowed to retain a modest portion of the margin generated by sales made to third parties from regulated portfolio resources (gas or electric). These incentives provide an incentive to maximize the utilization of resources whose fixed costs would otherwise be borne entirely by regulated customers, thus aligning the interests of customers and the utility.

Broad-based and targeted incentive mechanisms may be used together, particularly if there is a concern that a broad-based measure will encourage undesired behavior in a particular area of concern. Thus, individual service quality measures are examples of targeted IRM that frequently accompany a broad-based IRM. They provide incentives (and/or penalties) for behavior as measured against a pre-established benchmark for a measure that has been deemed to be an important indicator of customer service. In an electric generation context, incentives tied to the availability or heat rate of a specific unit or type of unit are examples of targeted IRM that may have been adopted to address past performance issues.

Many IRM approaches require measurement against a benchmark. This benchmark can represent the performance by the utility in a prior period or an index of performance of utilities that are deemed to be "comparable". Benchmarking against a comparative group of utilities is particularly valuable in identifying potential areas of improvement and best practices. In theory, benchmarks can also be used in both broad-based and targeted IRM. They can be used directly to establish a target, or if the benchmark is based on a comparable group of utilities, the utility target can be adjusted based on the rate of change for the comparable group. Benchmark-based IRM approaches present several implementation challenges as discussed in Chapter 3.4.

3.3 IRM as Currently Applied to Ontario's Electric Distributors

The Board has devoted considerable effort to the application of IRM for electric and gas distributors. The most recent policy consultation process, implementing "3rd Generation" incentive regulation (IR) for electric distributors, began in 2007 with Board reports issued in 2008 and 2009.[95]

The 3rd Generation IR plan, implemented beginning in 2009 for distributors whose rates had been rebased in 2008, is a price cap formula used to adjust rates for distributors beginning in the year after rates have been "rebased" through a cost of service review. The term of an electric distributor IRM was fixed at three years for all distributors (for a total effective rate period of four years). It is contemplated that rates would be rebased at the end of the IRM term and prior to the beginning of a new IRM plan.

Under the price cap formula, distribution rates increase by a measure of inflation, the Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI FDD), minus a productivity or "x-factor". The price cap adjustment applies to base distribution rates, but does not apply to rate surcharges including rate adders and riders, service charges, and other rate components.

The productivity factor is a two-part measure that includes a productivity factor plus a distributor-specific "stretch factor". The Board applied an estimate (0.72%) of the "Total Factor Productivity" (TFP) as the productivity factor to be applied to all distributors.[96] TFP attempts to measure productivity by focusing on the overall trend in productivity and ignoring the impact on economic output of more "transitory" factors such as weather and economic conditions. The Board segregated distributors into three cohort groups for purposes of assigning a stretch factor. Distributors in Group 1, the group that has demonstrated superior performance (and therefore less opportunity for increased efficiencies), were assigned a stretch factor of 0.2%. Distributors in Groups II and III were assigned stretch factors of 0.4% and 0.6%, respectively.[97] The group rankings, based on historical OM&A performance, are updated annually.[98] The Board acknowledged that considerable judgment had been applied given its relative inexperience with the reliance on benchmarking analysis that was required.

Distributors are allowed to petition the Board for recovery of revenue requirements associated with incremental capital investments of a non-discretionary nature that satisfy a

[95] See *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* issued July 14, 2008 and supplemental reports issued on September 17, 2008 and January 28, 2009.

[96] The Board adopted the 0.72% TFP with reservation as it was based on U.S. data, expressing a desire to base the TFP on Ontario-specific data as soon as reliable Ontario data is available. Supplemental Report, September 17, 2008, Page 12.

[97] Supplemental Report, September 17, 2008, Page 22. Stretch factor assignments were reported in the Addendum to the Supplemental Report of the Board, January 28, 2009.

[98] Addendum to the Supplemental Report, p. 12.

materiality threshold test. The adjustment is not intended to allow distributors to adjust rates to accommodate annual capital expenditures (CAPEX). The materiality threshold is based on the ratio of the incremental CAPEX to depreciation expense through application of the following formula:

Threshold Value = 1 + (RB/d) x (g + PCI x (1+g)) + 20%

Where:

RB = rate base included in base rates ($)

d = depreciation expense included in base rates ($)

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).[99]

The incremental capital for which the Board may provide rate relief is the new capital sought in excess of the materiality threshold. If the application is approved, a rate rider would be established to reflect an amount sufficient to accommodate the portion of the approved incremental spending that exceeds the threshold amount. The distributor must demonstrate that the requested amounts are directly attributable to the claimed cause where such cause is "clearly non-discretionary and clearly outside of the base upon which current rates were derived."[100]

If distributors are adversely impacted by an extraordinary event that is clearly beyond the activities contemplated when prices were established, they may request deferral accounting treatment of costs for future recovery through a "z-factor". These financial consequences must also satisfy a materiality threshold in order to qualify for deferred accounting treatment. The Board addressed the potential of a change in tax rates specifically, concluding that the impacts of such changes should be shared equally between customers and utilities.

Finally, the OEB IRM mechanism contemplates that there may be extraordinary financial circumstances that may result in a termination of the IRM plan before its term expires pursuant to an off-ramp. The OEB monitors distributors and may initiate reviews in cases of excessive over or under-earnings, defined for these purposes as earnings that are outside of a 300 basis point deadband around the authorized ROE.

The Board decided not to include an earnings-sharing mechanism (ESM), citing the fact that the productivity offset and stretch factor provide for a sharing of efficiency gains by customers from the outset of the plan.

[99] Supplemental Report, September 17, 2008, Page 33.
[100] Supplemental Report, September 17, 2008, Appendix B, Page VI.

3.4 Incentives to Improve Efficiency Under CoS Regulation

One of the principal reasons that IRM is an attractive option is the conviction that it will lead to greater and enduring efficiency benefits as compared to CoS regulation. A proper comparison to CoS regulation must reflect the fact that CoS regulation incorporates its own set of incentives. The relative strength of incentives to operate efficiently depends on the specific implementation details for both approaches but some general conclusions can be drawn.

For example, it is possible under CoS regulation for distribution utilities to retain all of the benefits of efficiencies (as well as profitable sales growth) between rate cases as long as the utility is able to avoid rate filings. There have certainly been historical periods where this has been possible due to growing sales, moderate inflation, CAPEX programs that contributed primarily to increased revenues, and the absence of regulatory requirements that dictated the timing of rate filings. More recently, the slowing of sales growth and extent of non-revenue producing CAPEX have led to more frequent rate filings at least for distributors, making it harder for them to retain efficiency benefits for extended periods under a CoS regime.

The perspective of some parties is that "regulatory lag" – that period between the time plant is placed in service and when its costs begin to be recovered through rates – creates an incentive under CoS to operate efficiently in order to offset the adverse earnings impacts of regulatory lag. Regulatory lag is a function of many factors but the three most important contributors are the definition of the test period, the rules that apply to post-test period adjustments, and the length of the regulatory review process. An historical test period based on average plant balances (as opposed to end-of-period) with minimal opportunity to incorporate pro forma adjustments that update plant balances results in a longer regulatory lag, all other things being equal. At the other end of the spectrum, a forward-looking test year with an opportunity to adjust rate base in response to CAPEX in subsequent years provides for a much closer matching between the time that plant is placed in service and when its costs are recovered from customers. However, in both cases, a dollar of efficiency benefit will be retained by the utility until its next rate filing, weakening the argument that regulatory lag contributes to more efficient operations.

One of the primary incentives reflected in CoS regulation is the threat of a prudence disallowance. Prudence reviews are after-the-fact reviews of either a major investment or a purchasing practice that provides a one-way penalty mechanism which creates an incentive to operate efficiently. The standards applied to prudence reviews are based on the exercise of reasonable judgment by the utility based on facts that existed at the time the decision was made. Thus, the threat of a prudence review promotes reasonable decision-making (and retention of documentation); its primary focus is not to drive improvements in efficiency. Prudence reviews are also not restricted to CoS regulation; they remain an element of regulation when IRM is applied.

The ability to retain efficiency gains under CoS regulation is also a function of specific ratemaking policies. In some instances, the regulator may also decide that a change to a ratemaking practice is appropriate in order to encourage certain behavior. For example, the adoption of CAPEX trackers for a significant portion of non-revenue producing investments would allow the utility to "stay out" of a rate filing for a longer period of time. The reliance on variance and deferral accounts can also impact incentives in a CoS model. For example, many vertically integrated utilities recover the fuel, variable O&M, and purchased power costs attributable to electricity production through a separate variance account with balances that are passed through to customers. Absent a target and/or sharing mechanism the pass-through feature can reduce the incentive to minimize these costs although the threat of an after-the-fact performance review does act as a restraint at least with respect to imprudent behavior. This is particularly relevant with respect to OPG given the number of variance and deferral accounts that are currently in place (see Chapter 2.1.4).

A more frequent outcome over the last decade, particularly in United States jurisdictions, is resolution of rate filings through multi-year settlement agreements. These agreements are based on CoS principles but often include elements that are common to IRM such as second and third-year step increases, ESM, and specified timing for the next rate filing. In that sense, they are akin to multi-year IRM plans that have cast-off rates based on CoS. The utility may share confidential forecast information on their investments and expenses in order to facilitate a multi-year agreement.

With respect to rate design, the recovery of fixed costs through rates that are tied to sales (or production in a generation context) also influences utility incentives. For example, within Ontario, the existing prices for the prescribed hydroelectric and nuclear facilities are calculated as one-part commodity prices. The one-part rate provides an incentive to OPG to maximize production as recovery of fixed costs through a commodity rate flows through to earnings.

In summary, when designing an IRM for OPG, it is important to recognize that the existing CoS framework has its own set of incentives and that these incentives will change with an IRM. Thus, IRM does not represent a change from a system without incentives to one with incentives. Furthermore, both CoS and IRM approaches reflect an allocation of risk between the utility shareholders and customers. Evaluation of the merits of a specific IRM approach relative to the existing CoS approach should reflect these considerations.

3.5 IRM Design Challenges

IRM presents numerous design, implementation, and measurement challenges that can affect the degree to which a particular mechanism realizes its objectives. Depending on the severity of the issue, a flawed IRM can unjustifiably either reward or penalize a utility.

3.5.1 Design Challenges

The most fundamental of design challenges is defining the activity that is being measured. Financial measures such as earnings that are the basis of ESMs depend on the accounting treatment accorded to several investment, expense and revenue activities. Depreciation, amortization and tax methodologies, for example, will affect earnings. Similarly, timing of revenue recognition will affect financial performance in a particular accounting period. Operating measures can also require fairly complex measurement definitions. Even a measure that appears relatively straightforward, such as a generation availability measure or a reliability measure, can involve a complex definition and measurement of several elements that combine to form the overall measure.

A related design challenge when defining a performance measure is the degree to which data is either available or can be compiled with reasonable effort and expense. It makes little sense to specify a performance measure if implementation requires an outsized (relative to the potential benefits of IRM) investment in IT/IS and other resources to collect the necessary data.[101]

The design challenges are perhaps greatest when performance is measured against a benchmark. A benchmark can be established relative to prior performance of the utility (e.g., relative to a level achieved in a prior period), or relative to a "comparable" set of utilities. In both cases, establishing an appropriate benchmark level requires judgment. Setting the benchmark too high may prevent the utility from being rewarded for improved performance; setting it too low may reward the utility for easily attainable performance – perhaps due to past inefficiencies. Benchmarks that are based on a comparable set of utilities require a definition of what is meant by "comparable" and identification of an appropriate comparable group. Of course, no group will be perfectly comparable. Some statistical techniques can be applied in an effort to "correct" for unique characteristics of members of a comparable group. Even where agreement can be reached on a comparable group, a particular measure may not be strictly comparable among the group members if a common definition is not employed. As noted above, earnings measures will vary depending on regulatory and accounting practices. Generation measures will vary depending on unit age and technology characteristics. At the same time, benchmark comparisons are particularly attractive if one believes that a utility's performance is inferior to its peers for reasons that cannot be explained by differing circumstances.

All IRM approaches implicitly assume that the future will be not be radically different from the past, at least in a structural sense. Yet game-changing events may occur during the term of an IRM that render the mechanism to be no longer appropriate. The introduction of a major new policy such as rate decoupling could require a termination or reopening of an

[101] Board Staff expressed a similar concern in its August 2, 2007 Scoping Paper in EB-2007-0673, the docket that considered the 3rd Generation IRM, "[t]he costs of administering the methodology, including the costs imposed on all participants, should not exceed the benefits to be derived from the methodology." Page 4.

IRM. A merger could result in structural changes in the way that a utility operates or in the divestiture of generation resources in order to satisfy market power concerns. It is not uncommon for a merger approval to result in a modification of an IRM for this reason.

A major plant addition during the course of an IRM may require special treatment. This can result in a modification to the IRM approach, similar to the merger approval impacts just identified, or require separate rate treatment (e.g., a capital cost recovery tracker) until such time as prices are reset at the conclusion of the IRM.

3.5.2 Implementation Challenges

Price-index formulas that establish prices based on inflation and productivity indices require special studies before they can be implemented. Selection of an appropriate inflation index reflects an effort to identify a price index or combination of indices that reflect activities performed by the utility business unit that is subject to the price formula. The choice of an appropriate inflation index depends on the indices that are available. There are national and regional inflation measures that represent broad areas of activity (e.g., either production or consumption). There are also construction and labor cost indices that are primarily used to adjust prices in construction project contracts. Finally, there are price indices that are narrowly defined to measure inflation in a particular factor input or product. The choice of an inflation index ultimately depends on selecting the most appropriate index (or combination of indices) among available indices that most closely represents the inflationary pressures that are likely to impact the utility's costs. A broad-based IRM generally reflects a broad economic index while a targeted IRM could reflect a factor price input that is directly related to the activity. The availability, costs and data quality are typically better for broad-based price indices compared with more specific indices that target an industry or a component of costs (capital, labour or materials). No measure will be perfect, but selection of an appropriate inflation index can usually be agreed upon without an extraordinary degree of controversy.

The same cannot be said for measurement of the productivity offset. These studies tend to be subject to design controversy and require large amounts of data and data analyses. The choice of an appropriate productivity offset is related to the inflation index. For example, if an economy-wide measure of inflation is used, then it will already reflect economy-wide productivity improvements. In this case, the productivity offset should reflect only the incremental productivity expected for the industry relative to the broader economy.

Initial approaches to IRM relied on judgment to specify the productivity offset (often referred to as the "X-factor"). In recent years, productivity offsets have been estimated using statistical techniques and cost and quantity data for the regulated industry. It is far from a perfect science as the most relevant data can be hard to obtain or obtained only with a significant lag. In the case of the 3rd Generation IR, it proved difficult to obtain Ontario-specific data for a long enough time period for these purposes.[102]

3.5.3 Performance Measurement Challenges

IRM requires measurement of performance usually at pre-defined intervals in order to implement price adjustments and rewards/penalties. Typically, the utility will make a compliance filing to present the underlying data, calculations, and results. Even though great care may have been taken when defining specific measures and associated calculations, it is possible, if not likely, that some data and calculations will require interpretation by the utility.

One of the primary measurement challenges is the allocation of common costs or revenues among activities, and particularly between activities that are subject to an incentive mechanism and those that are not. Allocation is, by definition, a subjective action and efforts should be made to agree upon important allocation methodologies as part of the design.

3.5.4 Unintended Consequences

Once a preliminary IRM has been designed, it is appropriate to take a step back and determine if further refinements are appropriate to deal with unintended consequences. These unintended circumstances include incentives that encourage behavior that may be beneficial during the term of the IRM, but have adverse consequences over the long run. For example, an incentive to maximize production from an aging asset may result in more rapid degradation of future capacity from that asset.

A common concern where the IRM applies to a subset of utility activities is an unintended incentive for gaming. This may be accomplished through cost allocation and other accounting practices where discretion is required and/or allowed. It may be possible to further refine the IRM approach if these consequences can be anticipated and reflected either in the design, calculations, or after-the-fact reporting. This concern is particularly applicable when implementing targeted incentives that provide a reward for cost savings or performance in one area of operations but are made possible by increased expenditures and/or capital investments that are passed through to customers. Under these circumstances, the utility may have an incentive to over-invest in order to realize an incentive.

One final unintended consequence is the potential for a disconnection between the benefits realized by utility shareholders and the sharing of rewards with utility management and employees. At the end of the day, the identification, implementation and overall success of any incentive program depends on the actions of men and women. The sharing of utility benefits with employees can be a powerful motivator and help assure that the IRM objectives are realized. If management incentives are adopted, they must be based on financial and

[102] See *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* issued July 14, 2008, page 14.

operating performance results that are audited by an independent third-party to ensure that the incentives are appropriate.

3.6 IRM for Generation

There is limited experience in designing broad-based IRM approaches for electric generation, either for an independent generation entity or for the generation business unit of a vertically integrated utility. This is particularly true with respect to incentives that focus either on increasing production or reducing the costs of producing power from regulated nuclear or hydroelectric facilities. There are incentives to promote the development of new hydroelectric resources in an effort to expand the role of renewable energy and to mitigate the impact of fossil fuel generation on air quality. However, there are several examples of targeted incentives that have been implemented with respect to a particular unit, a class of units, and entire supply portfolios.

It should also be noted that some governments have decided that the best way to achieve desired efficiencies in the generation sector is to restructure the electric industry and rely on competitive forces to impose discipline to rationalize capacity and achieve operational efficiency. Even where the supply portfolio continues to be regulated, competitive forces play a major role in the development of the portfolio and in the dispatch of the portfolio. Many regulators have adopted competitive bidding rules for new capacity. Furthermore, a large portion of generators in the US, Canada and in other countries sell their output in organized wholesale markets.

Ontario has gone part way, retaining OPG's relatively large portfolio of prescribed facilities that remain subject to price regulation. There are no signs that the regulated portfolio will be expanded either. However, before exploring IRM for OPG's prescribed assets, it is useful to discuss the concept of IRM for generation in a general context.

There is no theoretical reason why a broad-based approach cannot be applied to a generation business. There are two important considerations, however. First, it is necessary to measure costs and other aspects of performance for the generation business unit. Thus, it will likely be necessary to directly assign as many costs as possible among business units (including the generation business) and to allocate all common costs. Second, given the structure of the industry in much of North America, it is important to recognize that costs, revenues and earnings in a generation business will be driven in part by competitive wholesale markets – either for the electricity output, or for fuel inputs. These two considerations are interrelated to the extent that costs have to be allocated within a vertically integrated utility between a business that faces relatively few market restraints (such as the T&D business) and a generation business that must compete in wholesale markets. This provides an incentive to shift costs from the competitive business to other businesses.

Assuming that these cost allocation issues can be satisfactorily addressed, there is no reason why a broad-based price cap approach cannot be applied to a generation business – as long as there is a way to reflect the unique way that participation in an electricity market affects performance. This is certainly evident with respect to OPG's regulated assets, as will be discussed in Chapters 4 and 5. Thus, a price cap approach can be applied to the CoS, excluding input costs that are largely determined in competitive markets such as fuel. However, revenues will need to be apportioned in a manner that fairly assigns costs that correspond to the base CoS and those that reflect market forces. This is necessary to incent and measure efficiency gains in areas of the business that are not affected by a market.

Targeted incentives have been used in the regulated generation business. The most common forms are incentives to take advantage of profitable off-system sales, particularly where the wholesale market may not be fully developed, but also where there is surplus capacity that can be sold under contract to a third party for a month, season, year or longer. Some regulators allow the utility to retain a modest portion of the profits from these arrangements.

There is also some precedent for targeted incentive mechanisms that are intended to either improve the availability factor of a unit or group of units or the heat rate of fossil units. Concerns have been expressed with respect to each of these approaches. The concern with respect to availability factor incentives is that the utility may be encouraged to defer needed maintenance if they anticipate that an IRM approach will not continue beyond the current term. This would appear to be less of a concern for safety-related maintenance in the nuclear industry given the active oversight of a safety regulator. Heat rate incentives are challenged because they might lead a utility to purchase a higher quality – and more costly – fuel. However, at least one empirical study concluded that these incentives may provide a better alternative to more traditional regulatory tools such as management performance audits and prudency reviews.[103]

Finally, many utilities participate in generation performance benchmarking studies. Their participation is driven primarily by a desire to identify areas of potential cost efficiencies or performance improvement and not as an input to an IRM. A common concern in applying them for IRM purposes is that participating utilities each face unique circumstances that affect performance. Nonetheless, these studies frequently find their way into rate case and other regulatory proceedings where performance issues have been raised.

3.7 Evaluation Criteria for OPG IRM Options

Chapters 4 and 5 will identify several alternative approaches to IRM that should be considered for OPG's prescribed nuclear and hydroelectric facilities, respectively. Chapter 2 reviewed the regulation of these facilities from the enactment of O. Reg. 53/05 to the present and also described the performance of these facilities in recent years. This review included policy objectives that have a direct bearing on potential IRM approaches as well as areas of

[103] "The Effects of Fuel-Related Incentives on the Costs of Electric Utilities", Dr. Robert J. Graniere, Dr. Daniel J. Duann, and Dr. Youssef Hegazy, published by The National Regulatory Research Institute, November 1993.

OPG's nuclear and hydroelectric operations where a change in performance would yield benefits for Ontario and its electric customers. This Chapter 3 discusses IRM in more general terms but also proposes several potential objectives for an IRM.

These varying objectives provide a basis for establishing a set of criteria that can be used to evaluate alternative IRM options. These criteria can be divided into two broad categories: (a) IRM goals that relate to the desired outcome of an incentive mechanism, and (b) goals that relate to the implementation of IRM.

3.7.1 IRM Outcome Goals

There are at least five distinct types of goals for IRM that can be used as evaluation criteria:

(1) Promote Efficiency: refers to the goal of operating OPG's facilities in an efficient, cost-effective manner, seeking continuous improvement in their operation as well as in centralized support services that are allocated to the nuclear and hydroelectric businesses. These efficiencies are to be enduring and sustainable and contribute to the lowest reasonable price of electricity. Major capital additions should also be accomplished efficiently from both a budgetary and timeliness perspective.

(2) Contribute to Lower Electricity Bills: refers to the goal that OPG's nuclear and hydroelectric facilities be available to provide electricity to the Ontario market when such production provides the greatest value to retail consumers and that facilities, such as the Sir Adam Beck PGS that have a degree of operational flexibility, be operated in a manner that contributes to this same goal. Cost-effective expansions of hydroelectric facilities will also contribute to lower electricity bills. Lower nuclear costs allow lower regulated prices for the nuclear facilities, which contribute directly to lower electricity bills by reducing charges to the Global Adjustment.

(3) Preserve OPG's Financial Integrity: refers to the goal of maintaining OPG's access to capital markets on reasonable terms, and avoiding risks to OPG's financial wellbeing that might result from its nuclear generation investments and any other extraordinary events.

(4) Preserve the Reliability and Safety of OPG's Facilities: refers to the goal of ensuring an adequate supply of electricity for as many hours of the year as possible given the extraordinary contribution of production from OPG's facilities to Ontario's requirements, the imperative that OPG's hydroelectric and nuclear facilities be safely operated, and the goal of minimizing adverse impacts on the environment.

(5) Preserve the Value of OPG's Facilities for Future Use: refers to the goal of operating, maintaining, and investing in OPG's hydroelectric and nuclear facilities in a manner that extends their useful life for as long as can be economically achieved and maintains the quality of their performance in the years following the IRM term.

As with any set of goals, there are inherent conflicts among them. The most obvious of these relate to the conflict between cost reductions/lower customer bills and the goals of maintaining safe operations, the financial integrity of OPG, and the long-term value of the assets. Thus, a choice among IRM options based on these criteria may also require some judgment as to the relative importance of conflicting goals.

3.7.2 IRM Implementation Goals

The second set of goals relates to the implementation of IRM options. The best option from an outcome perspective may not be an acceptable option if it cannot be reasonably implemented or if it violates some other implementation goal.

(6) Ensure Accountability and Transparency: refers to a goal held by many regulatory authorities and government entities that they conduct their business in a manner that facilitates public review and oversight, subject to any constraints imposed for security purposes.

(7) Preclude Unintended Consequences: refers to the potential for IRM approaches to provide an opportunity for gaming the mechanism or otherwise resulting in outcomes that were not anticipated during the design and implementation phases.

(8) Ease and Cost of Implementation: refers to the goal of selecting an IRM that relies on information that can be readily (and accurately) compiled such that the resources required to implement the mechanism are relatively insignificant when compared to the potential benefits. Further, the costs of implementing the IRM plan, both with respect to the development of new measurement systems and the regulatory costs of subsequent price adjustment proceedings (relative to the continuation of a CoS approach or alternative IRM approaches) should be considered.

These eight goals will be used to evaluate the IRM options that are presented in Chapters 4 and 5.

4. IRM for OPG's Nuclear Facilities

The performance and cost characteristics of OPG's nuclear facilities were reviewed in Chapter 2. This section focuses on the issues associated with the design of an IRM for these facilities. Given the differences in technology, market participation, and performance between OPG's prescribed nuclear and hydroelectric assets, it is reasonable to recommend separate IRM designs for these two types of assets.

4.1 IRM Design Considerations

Consistent with the Memorandum of Agreement (MOA) between OPG and its sole Shareholder, and OPG's corporate objectives, the mission of nuclear operations is to generate clean, safe, low-cost electricity through dependable performance.[104] This mission points to objectives in three areas of performance: safety, electricity generation, and cost. Further, OPG has established four cornerstone values: Safety; Reliability; Human Performance; and, Value for Money.

Chapter 3.7 above proposed eight objectives for an IRM for OPG that are consistent with the objectives that have been established by OPG for its nuclear operations. As with the hydroelectric operations, it should be noted that the present payment-setting regime does give OPG performance incentives once the price for its nuclear output has been set. With the output price fixed and a certainty that any electricity that can be generated will receive the fixed price, any increase in the amount of electricity generated will increase OPG's returns.[105] Similarly, any decrease in costs that does not decrease output will increase returns. OPG therefore already has incentives to improve its nuclear performance both by increasing output and by decreasing its costs. However, greater incentives than those that can be accommodated in a CoS regime are clearly appropriate, given the performance issues associated with OPG's nuclear units.

4.2 Benchmarking and Targets

Chapter 3 discussed in general terms the design and implementation challenges in setting up an IRM regime. A concern common to IRM regimes is that of how to measure performance and how to establish performance standards. A critical factor is the availability of data to inform choices for the IRM regime.

4.2.1 The ScottMadden Phase 2 Benchmarking Report Results

The discussion of the performance targets an IRM regime would set for OPG Nuclear can start with performance targets set by OPG Nuclear management.

[104] Ontario Power Generation, Annual Information Form for the Year Ended December 31, 2010, dated March 4, 2011, p. 10.
[105] Assuming that the incremental cost of the power is less than its price.

Working with ScottMadden, OPG has developed a top-down gap-based business plan to improve its performance. The process started with top-down identification of the areas for improvement and performance targets. The targets were set to eliminate or narrow the gap between OPG's performance against the metrics and the top quartile of the benchmark reference. These targets were then discussed within the organization to arrive at concrete implementation plans to achieve them. The top-down plan replaced a bottom up approach in which business units produced plans that were aggregated into a corporate business plan.

OPG filed a 2010-2014 Nuclear Business Plan incorporating the targets developed in Phase 2 of the ScottMadden study.[106] The OEB accepted the ScottMadden benchmarking methodology and concluded that this effort established that OPG's nuclear operations can be successfully benchmarked against a comparator group.[107] The OEB noted OPG's enthusiasm for the top-down gap-based Business Plan approach, but expressed caution about the degree to which OPG appeared prepared to act on the resulting implementation plans.[108]

The OPG Nuclear Business Plan chose performance metrics in OPG's four cornerstone value areas. In total, there are 33 metrics for nuclear plants and an additional 14 for support units. The top-down Business Plan exercise set gap-based targets for 2014 for these metrics, allowing the sites and support groups to produce implementation plans and to fill in the years up to 2014.[109]

In the Business Plan,[110] OPG developed 30 initiatives in the four cornerstone value areas: 6 in Safety, 9 in Reliability, 6 in Human Performance and 9 in Value for Money. Of these, 7 were identified as Key Initiatives. Each initiative identifies an "owner" and contacts at the site and support group levels.

Table 11, taken from Phase 2 of the ScottMadden report, presents the hypothetical results of these initiatives in terms of closing or narrowing the gap.[111] The table duplicates the information presented in Table 3 in this document, showing the comparison in 2008, and adds the hypothetical values if OPG achieves the Business Plan targets. Darlington's reliability performance would improve to the top quartile on all three key indices, while Pickering would improve from the bottom to the third quartile and, on one measure, even to the second quartile. Darlington's "Value for Money" performance would rise to the top quartile while Pickering A and B's Value for Money performance would continue to be in

[106] Ontario Power Generation, "Nuclear Operations 2010-2014 Business Plan", filed in EB-2010-0008, Ex. F2-1-1, Attachment 1.

[107] Ontario Energy Board, Decision with Reasons, EB-2010-0008, dated March 10, 2011, p. 45.

[108] OEB, Decision with Reasons, EB-2010-0008, p. 46. The Board points out that the example case discussed in the ScottMadden Phase 2 Report called for termination of 13 FTEs, but OPG only terminated one. The Board expressed concern with OPG's degree of compliance with other actions if it did not comply in this clearly identified case.

[109] ScottMadden, "Nuclear 2009 Benchmarking Report, Phase 2 Final Report", filed in EB-2010-0008, Ex. F5-1-2, pp. 13, 14.

[110] OPG, "Nuclear Operations 2010-2014 Business Plan", pp.11-14. Ex. F2-2-2 Attachment 1

[111] ScottMadden, "Nuclear 2009 Benchmarking Report, Phase 2 Final Report", p. 15.

the bottom quartile, which is explained by the poor condition of the plants. As noted in Chapter 2, OPG argues that there are specific characteristics of these plants that make them expensive to operate.

Table 11: Current and Hypothetical Performance Against Benchmarks

	OPG Performance 2008					OPG Hypothetical Performance 2014		
	Top Quartile	Median	Pickering A	Pickering B	Darlington	Pickering A	Pickering B	Darlington
Reliability								
WANO NPI (Index)	96.19	62.46	60.84	60.93	95.67	70.9	81.3	98.80
2-Year Forced Loss Rate (%)	0.68	3.79	37.9	18.19	0.93	4.00	4.00	1.25
2-Year Unit Capability Factor (%)	90.97	84.31	56.6	73.17	91.99	84.3	81.00	93.30
Value for Money								
3-Year Total Generating Costs per MWh ($/Net MWh)	$ 28.66	$ 32.31	$ 92.27	$ 58.68	$ 30.08	$ 70.81	$ 64.80	36.75
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)	$ 18.06	$ 21.28	$ 82.62	$ 50.95	$ 25.10	$ 60.07	$ 52.47	25.82
3-year Fuel Costs per MWh ($/Net MWh)	$ 5.02	$ 5.37	$ 2.64	$ 2.68	$ 2.62	$ 7.45	$ 6.01	5.43

Code: Green = top quartile
White = second quartile
Yellow = third quartile
Red = bottom quartile
Source: ScottMadden Phase 2 Report, p. 15.

Achieving the targets in OPG's 2010-2014 Nuclear Business Plan would therefore represent significant improvements in performance. If an IRM were to adopt targets, these represent a possible starting point. In particular, the two reliability indices of FLR and UCF are key performance metrics that determine the ability of the nuclear plants to be able to contribute to electricity supply.[112] An overall Value for Money index, like total generation cost per MWh, influences the degree to which ratepayers receive a benefit from the nuclear power. This is also the key Value for Money index identified by ScottMadden.[113]

4.2.2 Reflecting Unique Circumstances

An issue for a nuclear IRM is the treatment of expenditures for the DRP. Given the use of a variance account, the capital expenditures for DRP will not impact rates at the time of their expenditure. However, the Board noted that it expected it could review their prudence by *ex post* comparison of actual to budgeted expenditures and that it could also review prudency

[112] The WANO NPI Index is a good overall indicator of performance, but because it is a composite of several sub-indices it is more difficult for management to control directly and may not be suitable as a target for an IRM.

[113] ScottMadden, op. cit., p. 6

before the expenditures are undertaken.[114] The Board also commented that it would be interested in examining whether there might be "performance incentives within the parameters of O. Reg 53/05 and the variance account."[115]

During the lengthy period of the DRP, OPG's output will be lower due to unit outages. If the first outage occurs between rebasings, OPG's total revenue will fall far short if the regulated payment amount is based on a calculation that includes production from shut down units in the denominator. This can be accounted for by removing both the costs and production associated with a shut down unit from the calculation of the regulated price and adjusting the payment amount and/or by establishing a variance account that tracks the decrease in revenues. To the extent that OPG is continuing to incur fixed costs (separate from the refurbishment investment) associated with Darlington units that are not operating, these costs can be recovered through the GA in order to preserve OPG's financial condition.

Another concern is the validity of the benchmarking. Some parties questioned whether it was appropriate to compare OPG Nuclear to a group that also includes operators of PWRs, and one argued that this invalidated top-down planning based on this comparative study.[116] As noted above, the Board ruled that the benchmarking in the ScottMadden report established that OPG's operations can be benchmarked. OPG, however, argued that its special circumstances militate against its being able to achieve performance in the top quartile for the Pickering plants, particularly in relation to cost. OPG asserted that the condition of the plants and other conditions of nuclear technology contribute to higher costs. However, many of the factors that OPG pointed to apply to all nuclear plants. This issue of appropriate targeting will need to be considered in the design of an IRM for OPG.

4.3 Performance and Market Impacts

Power from OPG's nuclear plants cannot readily be shaped to meet a daily load cycle because the OPG nuclear plants cannot be economically maneuvered to reduce output for short periods of time.[117] The impact of OPG nuclear output on the market is therefore to reduce prices across its operating period. This consideration suggests that pricing for the nuclear output should not depend on the market conditions during the particular hours when it is generated. As distinct from OPG's hydroelectric operations, there is no nuclear equivalent to the production shifting capability provided by the Sir Adam Beck PGS.

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[114] OEB, Decision with Reasons, EB-2010-0008, pp. 70-71

[115] Ibid.

[116] OEB, Decision with Reasons, EB-2010-0008, p. 42.

[117] The IESO has a stakeholder engagement process (SE-91) underway to discuss Renewable Integration. In the discussion paper, the IESO said that the dispatchability of nuclear units highly depends on the unit and the amount of dispatch required. Some units can achieve reductions of under 50 MW, but must be shut down for larger reductions than that. Some can reduce output by venting steam. The IESO is not specific about which units have such flexibility. IESO, "Dispatch Order for Baseload Generation, A Discussion Paper for Stakeholder Engagement 91", Nov. 2, 2011.

However, the existence of SBG for a significant amount of time can affect this conclusion. Since its nuclear power cannot easily be shaped, the output of the OPG fleet will be contributing to, or causing, SBG if it is running at the time of SBG. The presence of the nuclear power at those times increases costs to the system (reflected in the GA) because its price will be well above the low or negative market value of the electricity at times of SBG. While the nuclear output cannot readily be managed hourly, OPG can manage its outage schedule to reduce its output at times that are more likely to have SBG. In general, however, good industry practice is to schedule generation outages at times of low demand and therefore low price. OPG is required to coordinate its outage schedule with the IESO, so there is not likely to be a need for an incentive to influence OPG's outage scheduling.

4.4 Asset Condition & Investment Plans

OPG acknowledges that the material condition of Pickering A is poor. [118] OPG's business plan allocates resources to upgrade the plant, while at the same time it aims at increased efficiency in such areas as outage planning.

Concern was expressed by OEB staff about the expenditures for the Pickering B continued operations Project.[119] These expenditures are intended to allow the plant to operate until at least 2020, during the time of the DRP outages at Darlington. OPG notes that continuing Pickering B operations allows continued operation also of Pickering A; without Pickering B operating, OPG would not continue to staff the Pickering plant for just two (relatively small) operating units.[120] OPG's estimate of expenditures for continued operation of Pickering B is $190.2 million, all of which will be included in OM&A.[121] OPG's business plan calls for investment of $130 million from 2011 to 2013 for continued operations at Pickering B.[122]

In its Decision in EB-2010-0008, the Board discussed how it might review the prudence of the Pickering B continued operations expenditures. It noted that expenditures on nuclear extensions or rehabilitations tend to go over budget. Even though the Pickering B continued operations expenses will be in OM&A, any variance will be tracked in the variance account under O.Reg 53/05 and will be reviewed for prudence by the Board. In reviewing any expenditures above those approved in the EB-2010-0008 for prudence, the Board stated that it would consider whether OPG might prudently have offset these additional expenditures through cost reductions or deferrals in other parts of its operations.[123]

[118] The Pickering A part of the 2009-14 Nuclear Business Plan commits to "continue to improve material condition." EB-2010-2008, Ex. F2-1-1, Attachment 1, p. 29.

[119] OEB staff questioned both the cost and the effectiveness of the project. OEB, Decision with Reasons, EB-2010-0008, p. 50.

[120] OEB, Decision with Reasons, EB-2010-0008, p. 49 and EB-2010-0008, Ex. F2-2-3, pp. 5-6.

[121] OEB, Decision with Reasons, EB-2010-0008, p. 50. Also see note 51 above.

[122] Ontario Power Generation, Nuclear Operations 2010-2014 Business Plan, filed in EB-2010-0008. Ex. F2-1-1, Attachment 1, p. 16. $130 million is the total for the three years detailed in the table.

[123] OEB, Decision with Reasons, EB-2010-0008, p. 52.

4.5 IRM Options for OPG's Prescribed Nuclear Facilities

4.5.1 Incentives Under the Existing CoS Methodology

The existing CoS methodology for setting the price for OPG's nuclear assets provides incentives to OPG's management. Once the prices are set, the greater the output and the lower the cost that OPG Nuclear achieves, the greater is its profit. However, with prices being reset periodically based on a CoS review, the opportunity for continuing at this profit level is reduced because the lower cost or increased output will be built into the test year performance and decrease the regulated price. The additional incentive in an IRM regime is that such recapture of profits within a reasonable range (i.e. within the deadband if an ESM is in effect) does not occur during the regime, allowing greater rewards for exceeding the assumed performance level. A CoS regime subjects both capital and OM&A expenditures to a prudence review by the Board. As noted, the Board has reduced OPG's revenue requirement based on its estimate of costs that can reasonably be achieved.[124] With mechanisms like this, a CoS system can create additional incentives to improve performance, but the incentive remains limited by the frequency of CoS reviews and the expectation that any gains will be captured when rates are rebased as part of the CoS review.

4.5.2 IRM Options

Two types of IRM options for OPG's nuclear facilities are presented in this section. The first category is price cap mechanisms with variations in the manner that the initial cast-off prices are set and in the manner that the "x-factor" or productivity offset is established. The second set of options is targeted IRMs that focus on performance in a particular reliability or cost area that has been identified as an area of concern.

As discussed in Chapter 3, a price cap establishes an annual price by the formula:

$P_{t+1} = P_t * (1 + GPI – x + z)$, where
P_{t+1} is the price in year t + 1,
P_t is the price in year t,
GPI is the expected percentage change in an appropriate price index,
x is a productivity offset and may include a "stretch" factor, expressed as a percentage; and,
z is an allowance for any exogenous factors (z-factors) defined as part of the IRM plan, expressed as a percentage impact on prices.

In this formula, the key design elements are x, the productivity factor, and P_0, the starting period price. Typically, P_0 is set from the initial CoS review, providing the "cast-off" price.

[124] In its EB-2010-2008 decision, for example, the Board reduced compensation costs for 2011 by $55 million and for 2012 by $90 million, based mostly on moving OPG compensation levels down to the level of the 50th percentile of the Towers Perrin survey. OEB, Decision with Reasons, EB-2010-0008, pp 86-87.

The price can be simply set by dividing the revenue requirement determined as a result of the CoS review by the expected unit sales to arrive at a price per unit.

There are some advantages in applying the price cap IRM to OPG. It is familiar to the Board and the intervenors, being currently applied to all distribution utilities in the province. It provides a broad incentive to OPG to improve performance. By setting a fixed price that is no longer directly linked to costs, a price cap provides incentives to OPG to improve cost efficiency (reducing costs and increasing profit) and to decrease outages in order to increase output (increasing profits if price is above incremental cost). Its disadvantages in the case of OPG Nuclear include the fact that it does not directly target specific aspects of OPG's behavior. For example, it does not track whether OPG is achieving its Business Plan targets of performance improvement.

The three price cap mechanisms are Options N1 through N3. Option N1 is directly analogous to, and uses the framework from, the current methodology used to establish prices for Ontario's distributors. Option N2 substitutes for the x-factor by estimating a revenue requirement in years 2 through the end of the IRM term that is intended to reflect cost efficiencies that should be achievable based on an analysis of OPG's performance relative to more efficient units as determined through benchmarking data. Option N3 takes N2 one step further by reflecting some efficiency improvements in the cast-off prices (P_0) as well as in the remaining years of the IRM.

The first targeted IRM is Option N4, designed to reward OPG for improvement in UCF and/or LFRs. These mechanisms could be combined with Option N1, the traditional price cap approach. A potential IRM targeted to worker safety is also identified. A second targeted IRM, Option N5, is designed to provide an incentive to OPG to achieve construction cost and timing targets related to the DRP.

A final element of an IRM is an earnings-sharing mechanism and this is presented in this Chapter as Option N6 but it could potentially apply to all of OPG's regulated operations, including hydroelectric operations.

Option N1. Traditional Price Cap with a Productivity Factor based on an Aggregate Performance Indicator

This Option uses aggregate statistical and econometric methodologies to arrive at aggregate performance indicators that can be used to set the x-factor. Two factors are combined to arrive at the x-factor for OPG. First, the historical TFP growth rate of the industry is estimated and used to produce a forecast of TFP growth. It is assumed that an industry (and therefore a typical firm in the industry) should be able to increase its own productivity at least at this rate. Second, a benchmark factor is estimated to measure the difference between the firm's current performance and that of the industry. If the firm's performance is below the industry norm, its x-factor must include an additional "stretch" consideration if it is to reach the industry norm. That is, if the firm is lagging behind the industry, and industry productivity is growing, then the firm's productivity must grow faster than the industry's if it is to catch up.

As applied to OPG, this approach thus combines an overall industry productivity measure with OPG performance to produce a specific x-factor for OPG.

In this option, the basic x-factor represents an estimate of future TFP growth for the industry, generally arrived at by statistical means by analyzing historical data across a sample of firms in the nuclear industry. Such analysis requires gathering data in order to estimate an empirical cost function which is analyzed to determine the historical rate of change of the industry's total factor productivity. That rate can then be used as the basis for an estimate of the potential future improvement in total factor productivity during the period of the IRM regime.

Once this overall productivity factor is established, individual entities such as OPG may be held to a higher or lower standard, depending on their past performance, as is done in the Ontario distributor IRM. This process is called benchmarking because it compares performance among individual entities to an industry standard.

For the Ontario distribution utilities, the Board used a benchmark study provided by Pacific Economics Group for the OEB in its proceeding EB-2007-0627.[125] In that study, Pacific Economics Group estimated cost functions for all Ontario distribution utilities. Such functions constitute an econometrically estimated functional relationship between cost drivers such as the age of plant, customer density, size of utility, etc., and cost. This estimated functional relationship was then applied to each utility to determine whether its costs were lower or higher than would be predicted by the estimated functions, given the age of its plant, its customer density, etc., for each utility.[126] Those with lower costs are shown to be operating more efficiently than the benchmark; those with higher costs are shown to be operating less efficiently. For those with poorer performance, a larger stretch factor is added to their x-factor to provide incentives to improve performance to catch up to the industry standard. This is similar to the treatment of distribution utilities under the OEB's 3rd Generation IRM, where the basic x-factor is set to represent expected TFP growth and the firms' x-factors include a higher additional term for those whose measured performance is poorer. In the case of OPG Nuclear, the evidence from the ScottMadden study is that its performance is currently below the industry standard.

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[125] Pacific Economics Group, "Benchmarking the Costs of Ontario Power Distributors", March 20, 2008.

[126] The estimated equation is of the form C=f (age, density, …), representing the empirically estimated relationship between cost and the explanatory (right-hand side) variables for the sample as a whole. The values of the explanatory variables are then entered into the equation to get the cost predicted by the estimated relationship. A firm whose actual costs are above those predicted by the equation has poorer cost performance than the industry average.

It should be noted that estimating TFP has proven to be a challenging exercise due to the difficulty of obtaining the necessary data. This may prove to be more challenging in the nuclear industry although OPG may have access to sufficient benchmarking cost data.

Implementation Requirements and Assessment:

For this Option, two empirical studies are required, one to estimate future TFP growth and one to determine the current position of the firm (OPG Nuclear) relative to the industry standard.

The TFP estimation presents one of the most difficult implementation conditions, that of finding or conducting an appropriate TFP study. Several jurisdictions use or have considered TFP approaches to IRM. In Australia, for example, the Australia Energy Market Commission concluded that a TFP approach could lead to increased efficiency, but its implementation required more data on outputs and inputs of utilities.[127] Alberta is currently considering a TFP approach for utility regulation.[128] These cases refer to TFP regulation for distribution or transmission utilities, not for generation.

An appropriate TFP study for OPG Nuclear would preferably address all CANDU nuclear operators, but the population is relatively small. A larger population would be the North American PWR and PHWR operators, as used for the ScottMadden study. A TFP study would require more data than did the ScottMadden benchmarking study because it would need detailed data on input costs, technology and age of equipment, output, and other factors affecting cost. In its Decision in EB-2010-0008, the Board said it expects OPG to file a work plan and status report for a TFP study with its next filing.[129]

To determine the relative position of OPG Nuclear, a statistical benchmarking study like that performed by Pacific Economics Group for the Ontario distribution utilities will be required and will likely be as difficult as the TFP study. It requires similarly detailed cost data from an equally valid group of comparators in order to make an empirically estimated statement about the extent to which OPG Nuclear's performance exceeds or falls short of that of other firms in the industry, when accounting for the factors that affect that performance. One of the difficulties will be finding a proper specification of a cost function for nuclear generation.

If focused studies of these kinds are not performed, Option N1 can still be followed by using whatever sources are available for estimated TFP growth and for indication of the relative

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[127] The framework paper for this process, AEMC 2008, *Review into the use of Total Factor Productivity for the determination of prices and revenues*, Framework and Issues Paper, 12 December 2008, Sydney. This discusses a wide range of implementation issues and compares a TFP approach with a CoS approach to regulation.

[128] Alberta Utilities Commission, Proceeding 566,

[129] OEB, Decision with Reasons, EB-2010-0008, p. 156.

performance of OPG Nuclear. As the Board noted in the distributors' case, however, focused studies are preferred for regulatory use.

Applying the criteria described in Section 3.7, Option N1 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Positive*. Uses external data to determine how large the shortfall is and to set improvement targets.
(2) Contribute to Lower Electricity Bills: *Positive*. Successful implementation would lead to higher productivity, which by definition means accomplishing the same tasks using fewer resources and therefore lower costs.
(3) Preserve OPG's Financial Integrity: *Positive, but subject to risk*. If OPG Nuclear is able to improve performance faster than implied by the TFP factor, its rate of return will increase. If it is unable to improve performance, its rate of return will decline.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Positive to Neutral*. If plant performance improves, reliability will improve. On safety, CNSC will continue to require safe operations of the nuclear plants as a condition of license.
(5) Preserve the Value of OPG's Facilities for Future Use: *Risk of negative*. Decoupling prices from cost carries some risk that management will increase profits by neglecting required maintenance, but the neglect can have short-term consequences.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Neutral*. The analysis leading to the determination of TFP can be opaque because of its highly technical nature. But the IRM mechanism makes the price setting mechanism transparent.
(7) Preclude Unintended Consequences: *Positive*. Setting the x-factor using data and analysis that are entirely external to OPG Nuclear removes any possibility of gaming the analysis.
(8) Ease of Implementation: *Strongly Negative*. TFP studies are difficult to do because of the difficulty of getting data, the inevitable disparity between firms, and the likelihood that the applicability of the sample will be questioned. Aggregate cost studies are equally difficult. This option will occasion considerable discussion at the Board.

Option N2. Price Cap with Future Price Based on Specific Target Achievement

In this variant, rather than focus on estimating the x-factor through a statistical analysis, the nuclear production payment amount would be established based on the cost-of-service for only the initial year and the Board would establish the revenue requirement in years 2 through the term of the plan in a manner that reflects an estimate of achievable productivity improvements. Prices would be calculated by dividing this "more efficient" revenue requirement by anticipated production. The productivity improvements would be based on a measured or perceived gap between the performance of the regulated firm (OPG) and industry targets on one or several performance indicators. The factor could be chosen with respect to an overall cost performance indicator like cost per MWh, so that the decrease in revenue requirements would represent the cost reduction impact of narrowing the gap with the target performance. Alternatively, the reduction in revenue requirements could represent the cost reduction impact of narrowing the gap due to several performance indicators, such as staff numbers per unit for key functions. The information to make these determinations would come from benchmarking studies that the Board has ordered OPG to produce.

Effectively, in this option the future price will depend not on the actual costs in future years, but on the cost that would result if OPG achieves reasonable efficiency targets in future years. The future year price would be determined by dividing a target revenue requirement by a target output level. If OPG's performance exceeds these targets, its rate of return will be higher; if its performance is worse, its rate of return will be lower.

For example, if a benchmark for operating staff per unit is 133, and Pickering B's staff level is 180 per unit, the Board could determine that a reasonable target in year 2 of the IRM regime (the first year after the CoS year) would be, say, 170 per unit. Then the revenue requirement for year 2 would be based on that staff level (along with other relevant factors). The revenue requirement for year 3 could be based on, say, 160 per unit. Targets could be similarly applied to other cost areas to produce an overall revenue requirement that is set as a reasonable target.

Similarly, if the benchmarking data implies an FLR of 4% and Pickering B's projected performance is 18%, the Board could determine that a reasonable target for year 2 would be, say, 15%. Then the output level to be used in year 2 price determination would be based on a Pickering B FLR of 15%. The year 3 output could be based on, say, 12%.[130] Alternatively, if the FLR rate is 10% at the start of a 4-year IRM regime and the target level is 2%, the total output could be based on an assumption that FLR will decrease by 2% per year.

The price in the future year during the IRM regime would therefore be based on dividing the target revenue requirement (set by reference to reasonable performance targets) by the target output (set by reference to reasonable performance targets). In effect, this would become a targeted IRM, rather than one using a broad-based measure to set prices.

The Board indicated, in its Decision in EB-2010-0008, that it expects OPG to continue to file benchmarking studies. It directed OPG to file a benchmarking study like the ScottMadden report[131] and a more thorough compensation study.[132] These would provide the basis for the determination of reasonable performance targets.

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[130] This approach to setting output levels is applicable because OPG has no demand risk; when it is able to deliver power from its nuclear plants, the power is accepted. Because of the inflexibility of its plants, OPG Nuclear does not take the risk for SBG.

[131] OEB, Decision with Reasons, EB-2010-0008, p. 45

In taking this approach, one initial source for appropriate targets could be OPG Nuclear's Business Plan, which sets out what OPG Nuclear management thinks is feasible and which would presumably draw on the benchmarking and compensation studies. These could be a starting point for what is reasonable. The Board process can then test whether these targets represent enough of a challenge to OPG Nuclear management and could set targets that represent better performance than is contained in the OPG Nuclear business plan.

This approach will require considerable judgment to arrive at a determination of reasonable targets. Undoubtedly different parties will have different views on what is reasonable. But the parties are now more comfortable with discussions about benchmarking studies and their implications for OPG. The Board has also shown itself to be comfortable with making such determinations, as it did with respect to compensation in EB-2010-0008.

Implementation Requirements and Assessment:

Implementation of this option requires recent detailed performance benchmarking studies of the kind performed by ScottMadden and by Towers Perrin for the EB-2010-0008 case. To the extent that the benchmark comparisons are based on per unit cost measures, this would simplify these calculations. It could also rely on a broad range of indicators that allow comparisons (benchmarking) of a single firm's (in this case, OPG Nuclear's) performance on those specific indicators against those specific comparators with more detailed analysis to determine the impacts on costs and production. This option uses the comparative information to create incentives for OPG Nuclear to improve its operations towards the standards revealed in the study.

For this purpose, a benchmarking study using the same metrics as the ScottMadden report would have the advantage of having been tested in the EB-2010-0008 process. The disadvantages of using such targets is that the benchmarks may not be completely appropriate for OPG's nuclear fleet, as some intervenors have argued, that the targets in the OPG Nuclear Business Plan may not be aggressive enough, and that an IRM mechanism requires more focused targets than are presented by the large number of goals and actions laid out in the OPG Nuclear Business Plan. A benchmarking study to be used as the basis for setting a revenue requirement will no doubt be subject to greater scrutiny at the Board than was the ScottMadden study in EB-2010-0008.

Applying the criteria described in Chapter 3.7, Option N2 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Positive*. Uses external data to show what performance level is possible with best practice, and provides incentives to improve towards that level.

[132] OEB, Decision with Reason, EB-2010-0008, p. 87

(2) Contribute to Lower Electricity Bills: *Positive*. Successful implementation would lead to lower costs and higher output, reducing the regulated price for nuclear output and therefore reducing charges to the GA and consumer bills.
(3) Preserve OPG's Financial Integrity: *Positive, subject to risk*. If OPG Nuclear is able to reduce the gaps faster than the targets demand, it will be able to earn a higher rate of return. If it is unable to improve performance, its rate of return will decline.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Positive to Neutral*. If plant performance improves, reliability will improve. On safety, CNSC will continue to require safe operations of the nuclear plants as a condition of license.
(5) Preserve the Value of OPG's Facilities for Future Use: *Potentially Negative.* Decoupling prices from cost carries some risk that management will increase profits by neglecting required maintenance, but the neglect can have short-term consequences.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive*. The comparative studies set out for OPG Nuclear and for the public what OPG's performance is compared to other companies. The targets set objectives against which performance can be measured.
(7) Preclude Unintended Consequences: *Neutral to Potentially Negative*. Given the reliance on judgment and the incentive for OPG to support targets that are easier to achieve, it will be necessary to validate that targets are appropriate in order to avoid rewarding OPG for easily achievable improvements.
(8) Ease of Implementation: *Potentially Negative*. Implementing this option requires detailed performance data from a valid comparator group. It would also require resolution on a set of targets that would be used to set the future price, a matter likely to require the Board to evaluate competing intervenor proposals. This option would occasion extensive discussion and would place a significant burden on the Board to arrive at a reasonable set of targets.

Option N3: Price Cap with Initial Price Based on Efficiency Improvements

In this option, rather than establish the initial price based on a cost-of-service review, it would reflect a revenue requirement and/or a projected output level based on OPG Nuclear achieving meaningful improvements to the performance in the initial year. This option therefore takes one step further in decoupling pricing from actual costs by making even the initial price a function of cost or performance targets.

The Board applied a comparable adjustment to initial year prices in its Decision in EB-2010-0008, where it reduced the revenue requirement based on a reduction in staff costs of $55 million in the first year and $90 million in the second year.[133] OPG did not suggest that these reductions were feasible, and the Board expressed some doubt that they could be achieved. Rather the Board indicated that failure to achieve cost reductions should affect the shareholder, not the ratepayer; in other words, that OPG would earn a lower rate of return if

[133] OEB, Decision with Reasons, EB-2010-0008, pg. 87.

it failed to meet these cost objectives. Option N3 would make more extensive use of such an approach, determining the revenue requirement or output to be used in computing the initial price by assuming achievement of targets whose impacts on costs and/or production can be quantified.

For example, the projected output could be based not on the FLR projected by OPG Nuclear, but rather on the output that would occur if OPG Nuclear reaches a level of FLR that closes part of the gap between OPG Nuclear's performance and the median or top quartile of a benchmark. If the FLR were to be reduced from, say, 15% to 12%, then its projected output would be increased by roughly 3%, so the price would be set as the revenue requirement divided by the previously projected output plus an additional 3% from that plant. If the revenue requirement were also based on achievement of better performance, as it was for staff costs in the Board's decision in EB-2010-0008, the price would be the adjusted revenue requirement divided by the adjusted output.

The Board has made such adjustments in the past. In its Decision with Reasons for EB-2010-0008,[134] the Board rejected OPG's arguments that it should reduce the expected output from its nuclear fleet by 2 TWh to allow for what it called Major Unforeseen Events (frequently, unplanned extensions of planned outages).[135] OPG argued that such events have been a regular occurrence in the past and could reasonably be expected to occur again. Board staff and some intervenors argued that OPG had undertaken expenditures (paid for by ratepayers) with the purpose of reducing the frequency and severity of such events. Those expenditures should result in higher electricity output, and this benefit should accrue to ratepayers. The Board allowed a 0.5 TWh reduction in expected output as provision for Major Unforeseen Events based on the expectation that OPG's output would increase as a result of these expenditures.

<u>Implementation Requirements and Assessment</u>:

As with Option N2, implementation of this option requires a recent detailed performance benchmarking study of the kind performed by ScottMadden for the EB-2010-0008 procedure. It has detailed performance information on a broad range of indicators and allows comparisons (benchmarking) of a single firm's (in this case, OPG Nuclear's) performance on those specific indicators against those specific comparators. This option uses the comparative information to create incentives for OPG Nuclear to improve its operations towards the standards revealed in the study.

As with Option 2, part of the implementation will be agreement on the indicators to be used and the level of achievement that will set the revenue requirement and/or output level.

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[134] OEB, Decision with Reasons, EB-2008-0008, pg. 39.

[135] In this regulatory process, price per MWh is determined by dividing the agreed revenue requirement by the expected output in MWh. A provision for Major Unforeseen Events reduces the denominator in this calculation, raising the price.

Applying the criteria described in Chapter 3.7, Option N3 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Strong Positive*. Provides incentives for efficiency from the start of the IRM process. Uses external data to show what performance level is possible with best practice, and provides incentives to improve towards that level.
(2) Contribute to Lower Electricity Bills: *Strong Positive*. Successful implementation would lead to lower costs and higher output, reducing the regulated price for nuclear output and therefore reducing charges to the GA and consumer bills.
(3) Preserve OPG's Financial Integrity: *Positive, subject to higher risk*. If OPG Nuclear is able to reduce the gaps faster than the targets demand, it will be able to earn a higher rate of return. If it is unable to improve performance, its rate of return will decline. . The inclusion of productivity gains even in the rebased rates puts increased risk on OPG's financial situation if it is unable to realize expected gains quickly.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Positive to Neutral*. If plant performance improves, reliability will improve. On safety, CNSC will continue to require safe operations of the nuclear plants as a condition of license.
(5) Preserve the Value of OPG's Facilities for Future Use: *Potentially Negative*. Decoupling prices from cost carries some risk that management will increase profits by neglecting required maintenance, but the neglect can have short-term consequences.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive*. The comparative studies set out for OPG Nuclear and for the public what OPG's performance is compared to other companies. The targets set objectives against which performance can be measured.
(7) Preclude Unintended Consequences: *Neutral*. If the basis of the performance targets is related to the OPG Nuclear Business Plan, OPG may have an opportunity to set targets in the plan that can easily be achieved but OPG's business plan targets may not be accepted by the Board.
(8) Ease of Implementation: *Potentially Negative*. Implementing this option requires detailed performance data from a valid comparator group. It would also require agreement on a set of targets that would be used to set the future price. It would also require resolution on a set of targets that would be used to set the future price, a matter likely to require the Board to evaluate competing intervenor proposals.

Option N4. Specific Performance Targets

A price cap IRM could be coupled with one or more targeted IRM mechanisms, with specific incentives (and/or penalties) for reaching some defined targets. Since regulated payments to OPG Nuclear are included in the GA, payouts for these incentives need not affect the HOEP. OPG could be eligible for an additional payment (on either a lump-sum or a price adder basis) for reaching certain production targets; the payment could be graduated to provide greater rewards for higher achievement. Given the poor performance of the Pickering reactors, for example, OPG could be allowed a graduated fixed payment for reaching certain numerical targets for UCF or FLR for those units. Such a payment would effectively increase OPG Nuclear's incentives to improve the performance of those units because their increased output translates into a higher rate of return through increased sales.

Thus, if Option N1 were implemented, these targets could be based on achievement of UCF and/or FLR rates, providing a supplemental signal for OPG to increase its output and contribute to lower electricity costs. Options N2 and N3 already contemplate adjusting production to reflect improvements in output caused by UCF or FLR changes or by other factors.

A targeted mechanism could also be used to relate to performance relative to worker and public safety, such as the 2-Year Industrial Safety Accident Rate, which is a component of the WANO NPI. Targets of this kind are used in IRM or CoS designs to ensure that regulated companies do not respond to cost reduction incentives by reducing quality. Common targets include minutes of service interruption or time to respond to phone calls.[136] In the case of OPG, a critical element of its quality of service is its availability to generate energy, and as noted the IRM design provides incentives to maintain reliability and energy delivery. However, it is possible that, in meeting cost or staff reduction targets, some focus is taken off safety or other non-monetary objectives. The operation of the nuclear plants themselves is subject to monitoring and licensing by the Canadian Nuclear Safety Commission. Its standards cannot be compromised, at penalty of a fine or loss or non-renewal of the plant's license. Nuclear safety therefore would not be an appropriate target for performance incentives.

Other dimensions of public interest, such as worker safety and worker training, could be the subject of specific incentives.

<u>Implementation Requirements and Assessment</u>:

Implementation requires measurement of performance indicators that are already being compiled for management purposes. Some incremental effort may be required if the definitions need to be adjusted to accommodate an incentive mechanism. For example, it may be necessary to define and then exclude the impact of certain extraordinary events if the measure has associated penalties and rewards.

Applying the criteria described in Chapter 3.7, Option N4 is assessed as follows:

Ability to Satisfy Outcome Goals:

[136] For some early examples, see G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, "Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource- Planning Issues: Volume I", Energy & Environment Division, Lawrence Berkeley National Laboratory, November 1995 LBL-37577, Appendix p. 51, Table 3-7.

(1) Promote Efficiency: *Positive*. Provides incremental incentives for efficiency to supplement those provided through a broad price cap.
(2) Contribute to Lower Electricity Bills: *Positive to Neutral*. UCF and FLR incentives should contribute to lower electricity bills; safety measures address a different objective.
(3) Preserve OPG's Financial Integrity: *Positive, subject to higher risk*. Some rewards for improved performance, with risk from any exposure to penalties.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Positive to Neutral*. Safety measures will address worker safety. On safety, CNSC will continue to require safe operations of the nuclear plants as a condition of license.
(5) Preserve the Value of OPG's Facilities for Future Use: *Potentially Negative*. UCF and FLR incentives will improve short-term performance but could have a negative impact on longer-term performance.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive*. Broadcast of targeted performance measures, targets, and results will improve accountability and transparency.
(7) Preclude Unintended Consequences: *Positive to Negative*. If combined with a price cap, it can help avoid unintended consequences. However, if applied as a stand-alone option, care would need to be taken to ensure that the targeted incentive did not lead to less-than-optimal outcomes to the extent that productivity improvements focused narrowly on operational areas that were subject to the incentive mechanism. Under these circumstances, targeted incentives should also be designed to avoid "gold plating" of services and investments.
(8) Ease of Implementation: *Neutral*. Implementing targeted incentives generally does not require extraordinary implementation efforts, particularly if the measures are already being compiled for management purposes.

Option N5: IRM for DRP Capital Expenditures

The Board decided that O.Reg 53/05 applies to expenditures for the DRP. OPG will be allowed to place expenditures for the DRP into a deferral account that will eventually be recovered through electricity prices. The Board has not generally exercised oversight as the amounts are accrued, because they don't affect rates. The Board can review the expenditures for prudence before they are removed from the deferral account and put into the rate base. The Board suggested that its prudence review would focus on the differences between the expected expenditures and the actual expenditures, and it further commented that OPG management, which stuck with its current range of DRP cost estimates, cannot claim that cost overruns were unforeseen given that no CANDU reactor has been refurbished within its original budget.[137]

[137] OEB, Decision with Reasons, EB-2010-0008, pg. 72

The Board expressed interest in discussing the possibility of performance incentives with respect to these capital expenditures in the context of the variance account.[138]

For a successful IRM on these capital expenditures, the Board would need a frame of reference against which to measure OPG's performance on the DRP. Since the population of CANDU reactors that have been refurbished is very small, and since it is not clear that any of the previous projects form a benchmark for good practice, finding a level of performance that could be targeted for an IRM will be difficult. One possible benchmark would be the degree to which the actual DRP costs track OPG's original estimates. Such tracking would create an incentive for OPG to avoid underestimating refurbishment costs and give increased confidence in the validity of the business case for this large expenditure. Another option is to encourage OPG to reflect incentives in contracts with key vendors, including the Engineering, Procurement and Construction (EPC) vendor, and then mirror those incentives in a DRP incentive that would provide OPG with an opportunity to share in cost savings or be penalized for performance failures (cost and delays). However, this raises potential confidentiality concerns and may in fact discourage a vendor from providing favorable treatment to OPG for fear that other customers will demand similar treatment.

The extended period of the DRP calls for some special treatment of costs for the reactors when they are on an extended shutdown. OPG Nuclear's revenues from electricity output accrue entirely to energy production. The shut down reactors will not produce revenue. To meet a revenue requirement that includes the existing (pre-refurbishment) and ongoing fixed costs of the shut down reactors, the electricity price would have to increase. A charge that would better match the costs would be a fixed charge, applied to the GA, to carry the fixed costs of the shutdown reactor.

<u>Implementation Requirements and Assessment</u>:

This should not be a particularly difficult incentive mechanism to implement although establishing the cost and in-service targets is likely to require considerable judgment with parties likely taking opposing views with respect to the aggressiveness of the targets. Leveraging arm-lengths negotiations between OPG and its vendors and then reflecting these targets in the incentive mechanism may help address these tensions, if it can be done in a way that preserves the confidentiality of negotiations.

Applying the criteria described in Chapter 3.7, Option N5 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) <u>Promote Efficiency</u>: *Positive*. Provides incentives for OPG to aggressively manage the DRP from both a cost and timing perspective.

[138] OEB, Decision with Reasons, EB-2010-0008, pg. 73.

(2) Contribute to Lower Electricity Bills: *Strong Positive*. Reducing both the costs of the DRP and meeting or beating completion targets will yield lower electricity bills.
(3) Preserve OPG's Financial Integrity: *Positive, subject to higher risk*. Analysts generally pay close attention to major construction projects, particularly if there are risks of an adverse regulatory action. Incentives to perform could help address these concerns.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral*. A DRP incentive should not affect the overall reliability and safety of OPG's nuclear operations. It is assumed that the CNSC will monitor the DRP to ensure that safety concerns are being addressed.
(5) Preserve the Value of OPG's Facilities for Future Use: *Neutral to Positive*. The DRP is intended to preserve the value of the Darlington units; an incentive that increases the management focus on this effort could yield some positive benefits in this area.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive and Negative*. Communication of the DRP incentives will increase accountability and transparency, although vendor contract incentives may need to be accorded confidential treatment.
(7) Preclude Unintended Consequences: *Neutral*. It is difficult to conceive of unintended consequences of this incentive mechanism.
(8) Ease of Implementation: *Neutral*. This should not be a difficult incentive to design and implement.

Option N6: Earnings Sharing Mechanism

As discussed in Chapter 3, an IRM plan may have a significant impact on utility earnings particularly as circumstances may develop over the course of the plan that were not anticipated during the regulatory review process. These earnings variations may be undesirable either from the perspective of regulators or the utility and its investors. An off-ramp generally provides protection to the utility and shareholders against the "worst case" situation in which circumstances change so dramatically that they affect the ability of the utility to remain financially sound.

ESMs are a distinct IRM plan element that addresses upside earnings results as well as providing for a potential sharing of revenues before earnings decline to the point where the off-ramp is required.

The design of an ESM typically involves a deadband around the authorized return on equity within which no sharing occurs. In other words, the utility absorbs the entire earnings shortfall or retains the entire earnings surplus within this deadband. Sharing then occurs at pre-specified levels outside of the deadband on both the upside and the downside. The sharing percentages are an important design element and may reflect equal sharing of earnings above and below the deadband (e.g., 50 percent to shareholders; 50 percent to customers) or any other combination that sums to 100 percent. It is possible to have more than one, although rarely more than two, sharing bands or specified ranges with distinct sharing percentages.

One of the criticisms of ESMs is that they dampen the incentive that the utility has to pursue efficiency gains, particularly if investments are required to accomplish them. This concern can be addressed by expanding the size of the deadband, allowing the utility to retain a greater proportion of earnings before sharing begins.

Implementation Requirements and Assessment:

ESMs are calculated based on earnings and should be designed to take advantage of existing financial reporting requirements and timing. The period for an ESM should therefore match an existing financial reporting period. Since the calculation of earnings depends on accounting treatment for investments, expenses, and revenues, the calculation should be reviewed to ensure that any OPG's flexibility to interpret accounting guidelines does not provide an opportunity to game the results.

Applying the criteria described in Chapter 3.7, Option N6 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Moderately Negative*. Potentially dampens the incentive to aggressively pursue efficiency improvements, particularly ones that require significant investments.
(2) Contribute to Lower Electricity Bills: *Neutral*. Moderates the impact of earnings fluctuations outside of the deadband on both the upside and downside.
(3) Preserve OPG's Financial Integrity: *Neutral to Moderately Negative.* Provides some earnings protection on the downside, but only incremental to that provided by an off-ramp.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral*. Should not have any impact.
(5) Preserve the Value of OPG's Facilities for Future Use: *Neutral*. Should not have any impact.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive.* Communicates the earnings impact of an IRM on an annual basis.
(7) Preclude Unintended Consequences: *Neutral to Negative*. It is possible that an ESM will provide an incentive to adjust earnings to the extent that accounting regulations provide flexibility with respect to the treatment of certain activities.
(8) Ease of Implementation: *Neutral*. This should not be a difficult incentive to design and implement.

4.7 Conclusions

Each of these options has merit. Option N1 is the closest to the accepted practice of IRM in Ontario and other jurisdictions. All of the information needed to set the x-factor comes from sources outside OPG Nuclear. However, this option has the most intensive data and analysis requirements attributable to the need to develop an estimate of the x-factor composed of the TFP and the aggregate benchmark.[139] Ideally, OPG is in the best position and may be in possession of sufficiently detailed data that could be used to perform such a study. Considerable industry attention has been paid to benchmarking of costs and performance, although to a more limited degree specifically for generation as opposed to transmission and distribution activities.

However, Power Advisory has not found any other cases of IRM applied to a nuclear-only generation company. In the United States, the only regulated nuclear entities are vertically integrated utilities that generally have a two-part tariff with both fixed and variable charges and no IRM aimed at the nuclear component.

The OEB and OPG have been able to commission expert studies, such as those by Pacific Economics Group for the distribution utilities and by ScottMadden for OPG Nuclear. The only constraint on performing similar studies for OPG Nuclear is the possible lack of data from comparator nuclear generation utilities. However, as the ScottMadden report shows, data from nuclear operators are available from sources such as EUCG and WANO. Data may also be available from US sources such as the Energy Information Agency of the Department of Energy and from the Federal Energy Regulatory Commission, which collects data from all generators. OPG's filing in the next case will provide a work plan and status report for a productivity study.[140]

If sufficient data are not available for targeted studies, and no similar studies can be found, the implementation of a price-cap IRM for OPG Nuclear could either use Options 2 or 3 or it could use data from less closely aligned studies. Options 2 or 3 also have intensive data requirements, but the results of the ScottMadden study show that such data are available and can readily be analyzed. These options also appear to more directly attack the concerns that have been expressed by the Board and intervenors.

As discussed above, it is possible to combine more targeted measures with a price cap approach, particularly if Option N1 is implemented.

A DRP incentive is independent of other nuclear operations incentives and should be considered. An adjustment to the calculation of prices will likely be required to account for the combination of lost production and continued fixed costs during unit shutdowns.

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[139] The Board, as noted, directed OPG to prepare for such a TFP study in its Decision with Reasons in EB-2010-0008. OEB, Decision with Reasons, EB-2010-0008, p. 156.

[140] Ibid., p 156-157.

Finally, the adoption of an IRM for OPG nuclear, particularly during a period when the Pickering units may be subject to refurbishment, may lead to financial outcomes that were not anticipated. This supports the incorporation of an ESM as part of the plan as well as the specification of appropriate z-factors and off-ramps.

5. IRM for OPG's Prescribed Hydroelectric Facilities

The performance and cost characteristics of OPG's prescribed hydroelectric facilities were briefly reviewed in Chapter 2. This section focuses more narrowly on the potential goals of an IRM for these facilities, the behaviors that might support achievement of those goals, and incentives that are likely to encourage those behaviors.

With respect to goals of an IRM for OPG's hydroelectric facilities, Ontario will benefit to the extent that OPG's hydroelectric business operates efficiently and its facilities generate as much electricity as they are capable of producing when it is most needed (i.e., during peak periods) while maintaining safe (from the perspective of both OPG's employees and the general public) and environmentally sensitive operations. As discussed in Chapter 5.1, any incentive to produce electricity should be aligned with likely customer benefits, giving due consideration to the impact on the GA and SBG as costs that are ultimately borne by electricity consumers. OPG should also be encouraged to explore opportunities for economic additions to the capacity of its prescribed hydroelectric facilities. Finally, while cost savings are always important, it is essential that OPG continue to adequately maintain and invest necessary capital in its aging hydroelectric facilities to ensure that they remain available as low-cost renewable sources of electricity for as long as possible.

Any incentive program must reflect the fact that the energy producing capability of OPG's prescribed hydroelectric facilities will increase by approximately 1.6 TWh when the Niagara Tunnel project is completed.[141] It is anticipated that this project, currently scheduled to be in service in December 2013, will be operational before a comprehensive IRM structure is implemented.

Finally, it is worth noting that the Board did not find any particular efficiency or O&M cost level concerns during EB-2010-0008, perhaps due to the capital-intensive nature of hydroelectric costs, although the potential for IRM in this area is addressed in Chapter 5.3.2.

5.1 Current Hydroelectric Incentive Mechanism

As described in Chapter 3, OPG has had an incentive to increase its hydroelectric production since O. Reg. 53/05 followed by the adoption of the HIM as a result of the first payment review in EB-2007-0905. The HIM is a broad-based, relatively straightforward incentive designed to encourage OPG to maximize regulated hydroelectric facility electricity production during periods when the HOEP is highest. The mechanism primarily encourages it to use the Sir Adam Beck PGS to manage water flows and shift production from lower-price to higher-price periods. The use of the PGS leverages the differential in electricity

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[141] March 29, 2010 Presentation by John Murphy, OPG Executive Vice President, Hydro entitled "Hydroelectric Business Overview", Slide 10.

prices between adjacent periods as electricity is consumed during lower-price periods to pump water into the PGS reservoir.

The present form of the incentive, as affirmed in the most recent payment proceeding, EB-2010-0008, takes the following form:

$$\text{Payment} = \text{MWh}_{avg} \times \text{Regulated Rate} + (\text{MWh} - \text{MWh}_{avg}) \times \text{HOEP}$$ [142]

Thus, as HOEP increases, OPG has an incentive to increase its production levels. For the incentive to work, this incremental value, on top of revenues attributable to application of the regulated payment, must more than offset the decreased value from producing less than the average level during lower-priced hours. The ability of OPG to receive incremental revenues during higher-priced hours that more than offset the reduced revenues during pumping hours depends on the differential between prices. The reliance on the Sir Adam Beck PGS drives the decision-making calculus as OPG must purchase electricity during lower-priced periods in order to replenish the reservoir.

OPG is not merely a price-taker and, indeed, this is the primary motivation for the incentive mechanism. As OPG adds production during higher-price periods, it moderates price increases. As it reduces production during lower-price periods and increases demand to pump water, the price decrease is also moderated. OPG estimates that the net effect of its response to the HIM is a reduction in the market price of approximately \$1.14/MWh between December 2008 and December 2009.[143] This reflects a relatively modest increase in prices during off-peak hours and a somewhat higher decrease in prices during peak hours.

The HIM has been the subject of extensive discussion during prior proceedings. In the most recent order, the Board expressed two concerns that remain with respect to the current mechanism. First, the Board noted that while the OPG incentive is a function of the HOEP, the total price paid by Ontario consumers includes the GA. Thus, there is a misalignment between the value of the incentive to OPG and to consumers that is caused by the fact that the HOEP and the GA tend to move, by design, in opposite directions.[144] The Board concluded that, "the net benefits to consumers are likely substantially less than estimated by OPG on the basis of market price differentials alone."[145]

A second concern raised by the Board is the interrelationship between the HIM and the presence of SBG conditions. As noted above, OPG is largely insulated from the adverse impact of reduced generation through a variance account. The Board expressed the view that

[142] Pollution Probe noted that the MWh average value is calculated net of the energy used to pump during off-peak periods, asserting that 44% of that energy is recouped during production hours and that only 56% of the energy used to pump water should be deducted when calculating the MWh average value.

[143] Decision in EB-2010-0008, Page 144.

[144] Increases in the HOEP result in credits to the GA for energy provided by OPG's prescribed assets and for renewable contracts. Reductions in the payment levels for OPG's assets result in direct reductions to the GA and are not associated with an increase in the HOEP.

[145] OEB, Decision with Reasons, EB-2010-0008, Page 146.

the shifting of production from off-peak to peak periods is of greatest value if it also mitigates the level of SBG. OPG responds both to price signals, including the impact of water rental costs[146] and IESO directives in operating the PGS, and the Board requires documentation that OPG's PGS operations have been optimal. Under the current policy, the Board can adjust the SBG variance account if it finds that OPG had an opportunity to use the PGS to mitigate SBG and decided not to. Essentially, this implies that OPG should be maximizing its use of the pumping mode of the PGS during SBG conditions. In fact, the Board imposed the following obligation on OPG:

> When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly. The Board expects that this approach will have the effect of moderating the total level of incentive available to OPG, but concludes that it is a better structure to ensure direct benefits to ratepayers.[147]

Concerns that the incentive opportunity was excessive led the Board to modify the HIM to provide for equal sharing between customers and OPG above a capped amount. Further, the capped amount is reflected in the calculation of rates as a reduction in revenue requirement.[148]

As noted above, the Board also directed OPG to address the HIM in its next payment filing including, "an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of potential alternative approaches."[149]

5.2 OPG Benchmarks and Targets

OPG has established a set of broad goals to drive its hydroelectric business as well as a set of specific performance measures and targets to guide behavior. With respect to the former, OPG has expressed its goals as follows:

- Sustain and improve the existing hydroelectric assets for long-term operations;
- Seek to expand and develop existing hydroelectric stations where feasible;
- Operate and maintain hydroelectric facilities in an efficient and cost-effective manner;
- Maintain and improve reliability performance where practical and economical;

[146] OPG has indicated that there are circumstances in which it makes economic sense to spill water even when HOEP is positive when water rental costs are considered. December 19, 2011 Comments of OPG in SE-91.

[147] Decision in EB-2010-0008, page 147.

[148] Ibid., page 147.

[149] ibid,, page 148.

- Maintain an excellent employee safety record by ensuring that all worker safety laws are met;
- Strive for continuous improvement in the areas of dam and waterways public safety and environmental performance; and
- Build and improve relationships with First Nations and Métis communities.[150]

In addition, OPG has five performance measures that it wants its employees to focus on. To the extent that the interests of OPG and Ontario consumers are aligned, these measures could serve as a component of an OPG IRM.

These five performance measures are:

1. Target equivalent availability factors (EAF) are established for five of the six stations and for the capacity-weighted average of these stations. The EAF represents the percentage of hours during the year that a plant is capable of producing power at full capacity. OPG does not assign a target EAF to the DeCew Falls I station as it is only used when there is excess water flow that cannot be accommodated by the more efficient DeCew Falls II station. *Target*: OPG set an overall weighted average EAF target of 91.1 percent in 2011 and indicated that it expects availability to improve after 2014 after enhancements (conversions/ rehabilitations) are made to the Sir Adam Beck 1 station.

2. Equivalent Forced Outage Rates (EFOR) are established for the same five units and for the capacity weighted average. The EFOR is a measure of the reliability of a generating station generally expressed as a percentage of time that a unit is forced out of service. *Target*: OPG set an overall weighted average target of 1.3 percent in 2011.

3. OM&A Unit Energy Cost is a measure of the cost effectiveness *o*f a plant and is calculated as total O&M expenses, including any allocated hydroelectric costs but excluding GRC, divided by hydroelectric production.

4. Accident Severity Rate is a measure of employee safety and is calculated as the number of days lost by employees due to injuries incurred while on the job divided by the total number of hours worked by 100 employees in a year or 200,000.

5. Environmental Performance is an index developed by OPG that is intended to capture the incidence of spills, regulatory infractions, and energy efficiency.

The targets vary by year and reflect a number of factors including changes in facility condition such as potential degradation as well as improvements that are attributable to capital additions and other efforts, planned outages, and any benchmarking results. Pursuant to OPG's mandate, the company must also consider the objective of encouraging continuous

[150] OPG, 2010 Annual Information Form, page 15.

improvements. Without further insight into the establishment of these internal benchmarks, it is difficult to determine the extent to which these represent "stretch" targets, a matter of some judgment because internal corporate targets generally reflect some "stretch" element.

The first two measures appear to be the most relevant for consideration as part of an IRM. They reinforce the objective of maximizing the potential contribution of low-cost hydro resources to Ontario. However, they are annual values and it may be appropriate to calculate availability factors for periods when hydroelectric facilities provide the greatest potential value.

The third measure (per unit O&M costs) is dependent on the level of energy production as the denominator and may reflect conditions that are beyond OPG's control that impact production levels. There may be more straightforward ways to provide OPG with an incentive to reduce O&M costs if it is desirable to do so. While the level of O&M costs has been a matter of serious concern for its nuclear operations, hydroelectric O&M cost was not an issue in OPG's last rate proceeding. Further, consumers may derive a greater value from OPG spending an *optimal* amount on O&M expenses in order to ensure that the assets are sustained, than in having OPG spend a *minimal* amount. However, to the degree that the EAF and EFOR measures are also employed these may compensate for any adverse effects on output and availability from limiting O&M expenses.

The fourth measure (employee safety) is certainly important to OPG and has been included as an element in service quality plans for other utilities. However, it does not appear to rise to the same level of concern from a ratepayer perspective as other potential hydroelectric business incentive areas. A safety measure that incorporates public safety as well might be preferable if there are ways to reasonably measure OPG's contribution to public safety outcomes. Finally, the environmental performance indicator appears to be an attempt to capture an important objective, although the definition of the measure can be approached in several different ways.

As noted above, as one of the inputs to establishing targets for internal measures, and as support for its payment filings, OPG has benchmarked its hydroelectric O&M costs since 2006, contracting with Navigant Consulting and EUCG. These benchmarking studies were included in OPG's application in EB-2010-0008.[151] Focusing primarily on O&M costs within OPG's control (i.e., excluding GRC), the Navigant Consulting results vary by station. Sir Adam Beck II is a first quartile performer, whereas the older Sir Adam Beck I and DeCew Falls I stations are in the bottom quartile. This may be attributable to the respective age of these facilities. The Sir Adam Beck PGS and R.H. Saunders stations perform in the third quartile. The EUCG results exhibit a similar pattern although the Sir Adam Beck I and R. H. Saunders stations performed in the second quartile. OPG suggests that O&M expenditures for the Sir Adam Beck and R. H. Saunders stations may be higher than the

[151] Exhibit F1 Operating Costs – Regulated Hydroelectric

comparative group as OPG contributes to ice breaking and dam control activities working with the NYPA.

As discussed in Chapter 3.2, benchmarking against a comparative group of utilities is particularly valuable in identifying potential areas of improvement and best practices (if these are captured during the benchmark exercise). However, it must be applied with caution if it is relied on for IRM incentive/penalty purposes. True comparability is an elusive concept due to measurement differences, accounting differences, and particularly in the case of hydroelectric facilities, differences in facility ages and in the ways that facilities are designed and operated. Benchmarking seems more appropriate with respect to OPG's nuclear portfolio given the fact that CANDU units have common design characteristics and comparisons against other units also provide meaningful insights into performance.

When considering performance measures and associated targets for an IRM, it is appropriate to reflect the fact that OPG operates its hydroelectric assets as a portfolio. Thus, it is most appropriate to establish benchmarks for the prescribed hydroelectric facilities as a whole, excluding DeCew Falls I given its age and current operating profile. This is consistent with a general IRM approach of drawing the incentive boundary around as broad a group of activities as possible to minimize disincentives for the utility to operate inefficiently or minimize incentives to game the incentive mechanism. Further, an incentive mechanism that applies only to a single facility would require a detailed assessment of planned outages and capital investments over the term of the IRM in order to reflect any unique circumstances when setting the performance target. A plant-specific target would also need to reflect recent upgrades that have been paid for by customers when setting the target. These issues are not completely eliminated when considering the portfolio of assets, but individual events that affect an individual plant are of reduced consequence.

5.3 IRM Design Considerations

There appears to be general consensus that OPG should have an IRM for its hydroelectric business. Further, the primary interest in an IRM for OPG's hydroelectric operations is being driven by a consensus that the shape of OPG's hydroelectric production can have beneficial impacts on the cost of electricity to Ontario's residential, commercial, and industrial customers. There is also value to Ontario from increasing the overall production of electricity from OPG's hydroelectric stations. This can be accomplished by some combination of factors, including increases in the capacity of existing units, increasing the availability factors and/or reducing EFORs, or taking other actions that may increase the production levels, particularly if these actions represent sustainable improvements in performance.[152]

[152] Increasing EAFs or reducing EFORs will only increase production to the degree that the reduced outages result in a reduction in the amount of spilled water or allow the units to operate more efficiently.

There may be some interest in, and potential for, providing an incentive to OPG to reduce its O&M costs, but the potential impact on the costs of electricity to Ontario's customers is small relative to potential electricity market impacts and to the potential impacts of IRM as applied to OPG's nuclear business. Furthermore, short-term reductions in O&M costs that result in intermediate-to-longer term degradation in production or a shortening of the expected life of a hydroelectric facility are certainly not desirable. Thus, there is a need for a potential linkage between incentives related to electricity production and those related to O&M costs.

A broad price cap "inflation index-X" IRM should also be considered as an alternative to the current two-year reviews of OPG's entire cost structure, including projected changes to rate base. There is also an administrative benefit and IRM symmetry of applying a price cap to both nuclear and hydroelectric operations while also keeping OPG price reviews for its respective operations on the same schedule. A price cap mechanism would accommodate some growth in rate base while also providing an incentive to reduce O&M costs. One would expect that there will be significant data challenges in reliance on statistical techniques to estimate the productivity offset or "X-factor" for OPG's prescribed hydroelectric assets. A relatively modest productivity offset may be sufficient given the relatively small portion of OPG's costs that can be influenced by efficiency improvements.

However, as in the 3rd Generation IR for distributors, a provision for large capital projects would seem to be appropriate given the more lumpy nature of OPG's hydroelectric capital additions than is typical for a distributor. It may also be appropriate to apply performance incentives for certain capital investments. Based on the Niagara Tunnel experience, there may be benefits from incentives that are tied to budgets and timelines for major projects although it may be challenging to establish objective targets. Most likely, the appropriate level of cost recovery for large generation investments will continue to be subject to the potential for a formal prudence review. In addition, projects that add valuable capacity could be eligible for a higher return on equity if OPG assumes a corresponding degree of development and construction risk relative to the risks that might otherwise be assumed by customers.

Finally, at least two "quality of service" attributes should be considered. The first relates to public safety, a matter of increasing focus among Ontario stakeholders. The second relates to environmental quality as this one of the performance measures that has been implemented by OPG.

The subsequent IRM discussion is thus divided into three sections: options that incent production such as electricity market participation incentives, options that incent cost efficiencies, and service quality incentives.

5.3.1 IRM Options that Incent Production

The first four options are designed to influence OPG decisions that might affect either the total production from its hydroelectric facilities or the timing of that production. These options are intended to contribute to achievement of the following goals:

(1) Incent behavior that reduces the total cost of electricity to Ontario consumers, recognizing the contribution to the GA and any other factors in this regard;
(2) Consistent with (1), maximize production during periods when electricity prices are highest;
(3) Consistent with (1), shift production from off-peak to peak periods when doing so contributes to a lower total cost of electricity to Ontario consumers;
(4) Maximize pumping to the Sir Adam Beck PGS when SBG conditions are present and storage isn't full;
(5) Maximize availability factors, but not in a manner that degrades future production or reliability;
(6) Minimize EFOR factors, but not in a manner that degrades future production or reliability;
(7) Invest in incremental hydroelectric capacity when it is economical to do so; and
(8) Sustain the value of OPG's regulated hydroelectric assets, taking actions as necessary to preserve this value for the anticipated remaining life of the assets.

As noted above, there are four options, H1 through H4, that should be considered. As in Chapter 4, each option is defined and then assessed based on the set of outcome and implementation goals specified in Chapter 3.7. It is possible that some of these options could be combined as noted below.

Option H1. Extend and/or Modify the Existing HIM

While there are certainly concerns with respect to the existing HIM, it does provide OPG with an incentive to shift production from hours with lower than average prices to hours with higher than average prices. One concern is that the current mechanism may be too generous to OPG.[153] This concern appears to be driven in part by two factors that are largely beyond OPG's control: (1) the level of HOEP relative to the OPG's approved payment level; and, (2) the interrelationship between the HOEP and the GA. The first factor rewards OPG as HOEP increases, even though OPG may already have an adequate incentive to adjust its production at lower prices. The second factor contributes to the belief that the incentive is too rich because of the value to OPG appears to be disproportionate to the benefit received by Ontario electricity consumers. These circumstances can be addressed through a mechanism that shares the resulting incentive amount as provided for in the current mechanism. They can also be addressed more broadly through an earnings-sharing mechanism that applies to

[153] OEB, Decision with Reasons, EB-2010-0008, page 147.

earnings after consideration of all factors, including factors within and beyond OPG's control, and reflecting the impact of all incentive measures.

Second, there is the matter of whether the current incentive provides the proper price signals to operate the Sir Adam Beck PGS and take other actions that shift production from off-peak to peak hours. The current incentive, based on HOEP differences in adjacent periods and any water rental costs, provides a proper price signal as it reflects the marginal costs and benefits that are known to OPG at the time that it makes these decisions. The GA may be relevant for purposes of deciding how much value OPG should retain as a result of shifting production but is not a practical driver of behavior because it is not calculated until long after the fact, and even then, requires several iterations to finalize. This fact supports an incentive approach that first ensures that OPG's operating decisions are driven by appropriate price signals and a subsequent sharing of the created value after-the-fact after having made the right decisions.

Third, there is the matter of the impact of SBG on OPG's operations. To the extent that OPG already has an incentive to maximize off-peak pumping and adjacent peak-period production when SBG conditions are present, there does not appear to be an issue. Retention of the obligation for OPG to demonstrate that it has maximized its pumping activities during SBG conditions may be an administrative burden but requires documentation that OPG should be compiling for its own management purposes.

A more interesting set of circumstances occurs where SBG conditions exist, but OPG does not maximize pumping based on its forecast of relative peak and off-peak energy prices as well as the impact of the GRC. As indicated, OPG may be better off spilling water under certain circumstances even when SBG conditions exist. This is due in part to the fact that OPG is largely insulated from the impact of water spills through the SBG variance account and incurs the GRC for all production. At the same time, it must be recognized that the existence and severity of SBG conditions is largely beyond the control of OPG.

Continuation of the after-the-fact review of the use of the Sir Adam Beck PGS during SBG conditions is certainly an option. Another potential solution is to increase the incentive that OPG has to use its PGS to pump water during off-peak hours and produce electricity during peak periods. Given the fact that SBG conditions are largely beyond the control of OPG, it seems unfair to reduce the amount of its compensation for lost production due to the need to spill water. This could be accomplished by exempting OPG from payment of the Wholesale Market Service Charge (WMSC) for pumping operations. No matter what approach is taken, some continuing variance account is likely to be required to account for the fact that SBG conditions are beyond the control of OPG.

<u>Implementation Requirements and Assessment</u>:

Continuation of the existing HIM will require minimal, if any, incremental implementation effort. Modifying the OPG payment to remove the WMSC for pumping operations would require changes to IESO billing processes. Retention of the after-the-fact review of OPG hydro operations during SBG conditions continues the current burden on the Board, but should not require incremental effort on OPG as these reviews should be performed for internal management purposes.

Applying the criteria described in Chapter 3.7, Option H1 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Positive*. Provides proper price signals.
(2) Contribute to Lower Electricity Bills: *Moderately Positive*. Offsetting GA dampens impact on customer bills.
(3) Preserve OPG's Financial Integrity: *Neutral*. Financial impacts are more dependent on reasonableness of hydroelectric production levels reflected in the design of rates.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral.* Distinct issue.
(5) Preserve the Value of OPG's Facilities for Future Use: *Moderately Negative.* Places stress on Sir Adam Beck PGS.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive*. Measured by IESO.
(7) Preclude Unintended Consequences: *Moderately Positive*. Performance under SBG conditions may need to be monitored.
(8) Ease of Implementation: *Positive*. Requires minimal incremental effort.

One modification to this option that was considered but rejected is to apply an HIM formula only to the Sir Adam Beck PGS operations. All other hydroelectric production would be compensated based on the CoS payment level (or such level with price cap adjustments). This approach reflects the fact that the Sir Adam Beck PGS facility is the primary facility used to shift hydroelectric production from low-priced to high-priced hours. However, to the extent that other facilities have any ability to shift production, this incentive would be removed. Also, to the extent that OPG operates its Niagara facilities on an integrated basis, this approach could lead to less than optimal operations. Thus, it was determined that this approach would be inferior to the existing HIM.

Option H2. Shaping the OPG Hydroelectric Payment

An entirely different approach to provide OPG with an incentive to shift production from off-peak to peak periods is to shape OPG's prices to yield higher payment prices during peak hours than during off-peak hours. The Board already has considerable experience in developing such mechanisms. These approaches promote allocative efficiency by sending market signals that reflect the incremental value of producing and delivering power during peak hours given the fact that the electric system is designed to satisfy demand during peak hours, contributing to higher fixed costs in order to satisfy this demand. Shaped prices also require a fair degree of complexity (and associated controversy) in order to assign and allocate costs among periods. However, given the fact that the majority of OPG's hydroelectric production is from baseload stations, one option is to develop a peak price only for production from the Sir Adam Beck PGS. Ultimately, if the only reason to develop a shaped price is to encourage the proper use of the PGS, then the current approach of tying the incentive directly to the HOEP appears to be a more direct and accurate incentive, and avoids potentially distorting this market signal by introducing shaped payment prices.

Implementation Requirements and Assessment:

This option would require a significant amount of effort during the initial payment review to develop a cost allocation and rate design approach and model, although existing approaches and models are available to guide this effort. Billing processes and systems would also need to be modified to accommodate a new pricing methodology.

Applying the criteria described in Chapter 3.7, Option H2 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Moderately Positive*. Achieves a similar objective to Option H1 but does not respond to hourly price signals.
(2) Contribute to Lower Electricity Bills: *Moderately Positive*. Dampened incentive to shift production relative to Options 1 and 2 may also moderate contribution to lower electricity bills.
(3) Preserve OPG's Financial Integrity: *Neutral to Moderately Negative*. Actual production will vary from level used for billing determinants for an increased number of billing periods relative to Options 1 and 2.
(4) Preserve the Reliability and Safety of OPG's Facilities: Neutral. Distinct issue.
(5) Preserve the Value of OPG's Facilities for Future Use: Neutral relative to current approach.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Moderately Negative*. Somewhat more complex than current approach.
(7) Preclude Unintended Consequences: *Moderately Negative*. Complexity may distort incentives relative to current approach.
(8) Ease of Implementation: *Negative*. Considerable initial effort required.

Option H3. Availability and EFOR Incentives

Another IRM option that can be implemented in concert with either of the first two options is to establish availability and/or EFOR targets for individual stations or for the portfolio of stations. To the extent that it is possible to identify periods of the year where these measures are particularly important, it certainly makes sense for OPG to calculate and report these results. Further, to the extent that OPG can influence these measures and benefit customers by doing so then it might be appropriate to develop an incentive mechanism that applies to one or both of these measures. An incentive mechanism that establishes targets during pre-defined “high-value” periods would not be appropriate unless OPG has the ability to take actions that can influence availability during these periods, without significant adverse consequences on the overall performance of its hydroelectric assets.

Given the fact that OPG operates its hydroelectric assets as a portfolio, an IRM should be based either on the Niagara plants (excluding DeCew Falls I) or on these plants plus R. H. Saunders. It may also be appropriate to base such an incentive on a rolling average of three consecutive years in order to smooth out the effects of individual outages and to deter scheduling activities in such a manner as to benefit from the incentive mechanism.

Should this approach be adopted, there remains the challenge of setting an appropriate target level and incentive amount once these definitional issues are resolved. It is probably appropriate to set the target based on recent experience during years in which there were no extraordinary events. The target would therefore reflect normal, but not stretch conditions. Nor would it reward OPG for performance that is improved over a relatively poor performing year.

The value created by such an incentive could be estimated by calculating the market benefit of a higher availability factor throughout the year and then estimating the net impact on the GA. However, this is not a simple calculation and would require a sophisticated market model and several simplifying assumptions. An approximate and less perfect approach based on a reward for each tenth of a percent improvement in performance could incent the desired performance without requiring complex electricity market modeling. The reward could be based on approximate calculations and incorporate judgment to ensure that the reward level is high enough to incent the proper result. For example, a reward in the millions (but not tens of millions) for every percentage point increase in the availability factor would provide an adequate incentive to OPG while providing substantially more value to Ontario’s consumers.

<u>Implementation Requirements and Assessment</u>:

This option depends on measures that are already being compiled for management purposes. It may be possible to perform an analysis based on IESO data that estimates the incremental value of improved EAF or EFOR performance and this is likely to require a substantial effort to define and then perform the analysis and then present the results to the Board and other stakeholders. A judgmental approach, by definition, would require substantially less effort.

Applying the criteria described in Chapter 3.7, Option H3 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) <u>Promote Efficiency</u>: *Positive.* Assumes that it is combined with Option H1.
(2) <u>Contribute to Lower Electricity Bills</u>: *Moderately Positive.* Increases the availability of the hydroelectric assets to provide low-cost power, dampened by the GA offset.

(3) Preserve OPG's Financial Integrity: *Moderately Positive*. Depends on difficulty of achieving target levels.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral*. Distinct Issue.
(5) Preserve the Value of OPG's Facilities for Future Use: *Moderately Positive*. Maintenance activities necessary to improve performance may also enhance longer-term asset condition.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Positive*. Should contribute to greater understanding of the value of hydroelectric production.
(7) Preclude Unintended Consequences: *Moderately Positive*. Conceivable that driving performance based on one or two measures could have unintended consequences that are not contemplated until the measure is implemented.
(8) Ease of Implementation: *Neutral to Moderately Negative.* Depends on complexity of analysis used to establish incentive reward/penalty structure.

Option H4. Incentives to Maximize "Other Revenues"

A final set of market-related incentives relates to the use of the prescribed hydroelectric facilities to provide ancillary services. The current policy is to reflect a forecast of ancillary revenues in the calculation of rates and to record the difference between this forecasted amount and actual revenues in a variance account. Tracking 100% of the difference between actual ancillary revenues and the amount reflected in rates in a variance account eliminates any incentive for OPG to increase these revenues. Changing the structure of this account is appropriate only to the extent that there are actions that could be taken by OPG to increase its ability to provide ancillary services or to provide more of them (i.e., operating reserves) during hours when prices are highest. However, given the relatively limited revenues associated with these services and the fact that high operating reserve prices are highly correlated with high HOEP, this isn't viewed as a major opportunity. More importantly, adoption of this option may invite a more detailed review of OPG competitive actions, a prospect that is likely to raise concerns from OPG. For this reason, the incentive might be best measured and applied at an aggregate level.

With respect to the revenues from support provided to Hydro Québec and water transactions with NYPA, the existing three-year average approach provides an incentive to increase these revenues without introducing a new mechanism for what would probably be a relatively modest potential incentive for either OPG or customers.

Under any of these options, it is necessary to review the appropriateness and current structure of existing variance accounts. These relate to the impact of water levels on OPG's revenues, the amount of ancillary revenues, and variations of the impact of SBG on OPG's production levels.

Implementation Requirements and Assessment:

This option should require minimal implementation effort. It relies on information that is already being compiled by the IESO for billing purposes.

Applying the criteria described in Chapter 3.7, Option H4 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Slightly positive*. OPG should already be operating in a manner that generates ancillary service revenues.
(2) Contribute to Lower Electricity Bills: *Slightly positive*. Some incremental value may be created and flowed directly through to customers through the GA.
(3) Preserve OPG's Financial Integrity: *Slightly positive*. Some incremental profit to OPG through a sharing mechanism, assuming that it is a one-way incentive, i.e., that OPG is not penalized for lower than a forecast level of ancillary service revenues, which are largely beyond their control.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral*.
(5) Preserve the Value of OPG's Facilities for Future Use: *Neutral to Slightly Negative*. Could incent operations of Sir Adam Beck PGS that contribute to degradation of the facility.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Neutral to Slightly Positive*. May require more detailed examination of OPG competitive operations, a prospect that is likely to raise concerns from OPG's perspective.
(7) Preclude Unintended Consequences: *Neutral to Slightly Negative*. Could result in unintended consequences although financial benefit to OPG is likely to be modest.
(8) Ease of Implementation: *Positive*. Not difficult to implement, assuming that regulatory approval is granted.

5.3.2 IRM Options that Incent Cost Efficiencies

As discussed in Chapter 3, broad-based price-cap incentives are designed to encourage utilities to operate more efficiently by providing them with an opportunity to increase earnings during the term of the IRM. This results from weakening the link between costs and prices after initial cast-off prices have been established using CoS principles. The price cap is the most common approach and is currently applied by the Board to Ontario's electric distributors.

As discussed in Chapter 2.2.2, the circumstances faced by OPG with respect to its prescribed hydroelectric facilities are substantially different from those faced by Ontario's electric distributors. A much greater proportion of OPG's cost of service is comprised of fixed costs, and in particular, the aggregate costs from the return of and on capital and associated income taxes. OPG's capital budget tends to be composed of a smaller number of distinct investments although the contribution of some projects to rate base will be significant. While it is important in both the distribution business and in OPG's business to adequately maintain the value of the assets, failure to do so in a manner that would remove one of the hydroelectric stations from service for an extended period would have much more drastic consequences than the issues typically faced by a distributor.

The goals with respect to a potential O&M incentive mechanism are more straightforward and similar to objectives that are common with existing T&D IRM plans. As noted above, there does not appear to be the same degree of concern with respect to the efficiency of OPG's O&M services for its hydroelectric business as there is for the nuclear business. That does not mean that there aren't opportunities for improvement, however.

There are two basic options that are intended to reduce costs: a price cap approach that applies to the entire hydroelectric business and a more limited O&M incentive.

Option H5. Price Cap Approach

This approach could be implemented as it has been in the 3rd Generation IR for distributors although it would be necessary to develop inflation and productivity factors that correspond to hydroelectric generation. Thus, special studies based on available data would be required. The fact that there may not be any similar mechanism in place elsewhere is likely to present some initial data and analytical challenges. Given the capital-intensive nature of these facilities, and the limited focus on hydroelectric OM&A costs in recent payment reviews, the prospect for significant reductions may be limited. For all of these reasons, it may be adequate to use the same inflation index as in a nuclear price cap (assuming it is a broad Canadian economy production-related index) and incorporate a relatively modest productivity offset, based on judgment.

Given the relative contribution of the GRC to total payment levels and the fact that it is beyond the control of OPG, it should be excluded from the application of the price cap mechanism.

Given the nature of capital additions for hydroelectric operations, it is more likely that a price cap approach will yield earnings that deviate from the authorized return than would occur in the distribution business. It is certainly possible price increases driven by inflation will produce substantial earnings in a year in which CAPEX is relatively low. This can and should be addressed through a form of earnings sharing outside of deadband. Given the likely adoption of an electricity market component to the IRM, the earnings sharing mechanism should apply to both the price cap and electricity market impacts.

Finally, a separate rate accommodation to account for extraordinary capital projects would be as applicable, if not more applicable, for the hydroelectric business than it is for electric distributors.

Implementation Requirements and Assessment:

A significant implementation effort will be required for the initial development of the price cap assumptions. Some effort will be required for identification of an appropriate inflation index but considerable quantitative analysis will be necessary to develop the productivity offset. Substantial resources will also be required by the Board and other stakeholders to review these assumptions. These efforts will be aided by the fact that a price cap approach has already been implemented for Ontario's electricity distributors.

Applying the criteria described in Chapter 3.7, Option H5 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Moderately Positive*. Should contribute to modest O&M savings.
(2) Contribute to Lower Electricity Bills: *Moderately Positive to Moderately Negative*. O&M savings provide direct benefits through the GA. However, price cap would apply to the entire payment amount, including the recovery of capital costs. It is possible that increased revenues from a price cap may more than offset any increases in the CoS.
(3) Preserve OPG's Financial Integrity: *Neutral to Slightly Positive*. Price cap provides an opportunity for OPG to retain efficiency improvements during the term of the IRM.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral to Moderately Negative*. May require reporting on reliability and safety to ensure that incentive to reduce costs does not have an adverse impact on performance.
(5) Preserve the Value of OPG's Facilities for Future Use: *Neutral to Moderately Negative*. Cost cutting in maintenance area could degrade future performance without assurances to the contrary.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Neutral.*
(7) Preclude Unintended Consequences: *Moderately Negative*. Refer to (4) and (5).
(8) Ease of Implementation: *Moderately Negative to Negative*. Initial implementation will require significant effort.

Option H6. O&M Efficiency Incentive

An IRM that establishes the amount of O&M costs that are included in the payment amount, with the remaining payment components requiring a continuation of the current approach (perhaps extended to a third year), is an alternative to the price cap approach. However, focusing only on O&M costs ignores the tradeoff between capital investments and O&M costs that impact many investment decisions.

This consideration along with the absence of specific concern with respect to O&M costs makes this option less appropriate than the price cap approach.

Implementation Requirements and Assessment:

Modest implementation effort will be required to define the measure in a manner that precludes any opportunity for gaming that could result from accounting practices (i.e., assigning specific expenses and investments to accounts).

Applying the criteria described in Chapter 3.7, Option H6 is assessed as follows:

Ability to Satisfy Outcome Goals:

(1) Promote Efficiency: *Moderately Positive*. May be preferable to a price cap given OPG's cost structure, particularly if the primary objective of a CoS incentive is to reduce O&M costs.
(2) Contribute to Lower Electricity Bills: *Moderately Positive*. O&M efficiency gains may not be substantial but they do contribute directly to a reduction in the GA.
(3) Preserve OPG's Financial Integrity: *Moderately Positive*. Some opportunity to increase profit.
(4) Preserve the Reliability and Safety of OPG's Facilities: *Neutral to Moderately Negative*. May require reporting on reliability and safety to ensure that incentive to reduce costs does not have an adverse impact on performance.
(5) Preserve the Value of OPG's Facilities for Future Use: *Neutral to Moderately Negative*. Cost cutting in maintenance area could degrade future performance without assurances to the contrary.

Ability to Achieve Implementation Goals:

(6) Ensure Accountability and Transparency: *Neutral.*
(7) Preclude Unintended Consequences: *Moderately Negative*. Refer to (4) and (5).
(8) Ease of Implementation: *Neutral to Moderately Negative*. Should not require a substantial effort, particularly as compared to H5.

5.3.3 Service Quality Incentives

As to the safety of the general public around OPG's hydroelectric facilities, it is certainly appropriate to track and investigate all incidents that occur. However, given the discrete and unique nature of incidents and the fact that some may not have been preventable, it doesn't appear to be practical to craft a reasonable, formula-based incentive mechanism. A more appropriate regulatory approach is to address the issue in a payment proceeding based on relevant facts and the application of judgment.

5.4 Conclusions

First, with respect to electricity market participation incentives, it is essential that some form of the HIM be retained. The formula need not be changed if it provides the proper price signals and any concerns regarding the "richness" of the incentive are better addressed through a sharing mechanism. Availability or EFOR incentives should be considered but only if OPG can take reasonable actions to ensure that its facilities are available when they provide the greatest value. These steps are likely to accomplish the same objectives as shaping the payment without unnecessarily complicating the payment setting calculations. Exempting OPG from payment of the WMSC should be considered if it strengthens its incentive to operate the Sir Adam Beck PGS to maximize its contribution to customer benefits. The current regulatory approach of reviewing the OPG's actions to mitigate the adverse consequences of SBG is acceptable and should be continued as opposed to the alternative of developing an incredibly complex HIM to address circumstances that are largely beyond OPG's control.

Second, with respect to OPG's costs, a price cap approach seems to be appropriate particularly if a similar mechanism is adopted for OPG's nuclear assets. The mechanism should accommodate separate treatment for recovery of the revenue requirements associated with extraordinary construction projects. Care should be taken to implement the price cap in order to avoid an opportunity for excessive earnings. For this reason, an earnings-sharing mechanism that applies either to the hydroelectric business or to OPG's entire regulated business should be considered. However, if a price cap is not adopted for OPG's nuclear operations, then the O&M focused incentive for hydro-electric operations should be considered as an alternative to the price cap as the implementation effort is reduced and it more directly targets the potential efficiency improvements.

Finally, it does not appear necessary to adopt any service quality measures at this time.

6. Conclusions, Recommendations and Implementation

Several IRM options were identified and assessed in Chapters 4 (nuclear) and 5 (hydroelectric). As is evident from these discussions, IRM options are not mutually exclusive and can be combined to achieve an overall desired outcome. Thus, it is possible to combine a broad IRM such as a price cap mechanism with more targeted performance measures that are designed either to encourage output during particular hours (hydroelectric) or send a stronger signal that higher unit availability factors provides particular value to Ontario's customers (nuclear). It is also possible to apply an ESM, discussed in Chapter 4 as Option N6, on top of a price cap or targeted IRM (or both) and to apply it to all of OPG's prescribed facility operations. These mechanisms are particularly attractive for IRMs as performance under an IRM can be more difficult to predict than under a traditional CoS approach.

As discussed in Chapter 4, the DRP provides a particular challenge for IRM and we recommend that it be treated in a manner that isolates the impact of related unit outages and therefore preserves the potential to use IRM to achieve operating efficiencies in the units that continue to operate.

6.1 General Conclusions

The most important conclusion is that IRM should be applied to OPG's regulated nuclear and hydroelectric businesses. With respect to nuclear operations, the benchmarking analyses that have been performed indicate that OPG's nuclear units have performed poorly, and dramatically so with respect to the Pickering units. Although the performance concerns are primarily associated with the Pickering units, the IRM should include all units in order to focus on efficiency improvements across the fleet and to avoid any incentive to shift costs among units. Further, the ScottMadden benchmarking results indicate that improvements in this performance can be achieved by OPG actions and are not entirely beyond the control of OPG, although certain challenges related to the condition of the units have been acknowledged. It should be noted that the ability of the plants to operate safely has not been called into question.

With respect to the hydroelectric business, the existing HIM has been working fairly well although there are concerns as to whether more could be done to mitigate the potential adverse consequences that result from SBG conditions. These conditions are largely beyond OPG's control and Power Advisory has not identified an improvement to the mechanism that would address this issue in a straightforward manner. Power Advisory has also noted that cost efficiencies have not been a major concern with respect to OPG's hydroelectric business although a price cap mechanism may be successful in generating incremental O&MA efficiencies.

6.2 Summary of Recommendations

Based on our assessment of the options presented in this report, and in consideration of how they might be combined to achieve a comprehensive outcome that will benefit Ontario and its electricity customers, Power Advisory makes the following recommendations:

<u>Nuclear Operations</u>:

- Establish the cast-off prices based on the cost-of-service, reflecting a modest increase in the Unit Capability Factor (UCF) of the Pickering units.

- Adopt price determination method Option N2, with OM&A and other cost efficiencies and increased production reflected in the calculation of prices in years 2 through the end of the IRM term (assumed to be at least four years in total).

- Consider an additional incremental targeted incentive(s) directed toward continuous improvements in UCF and Forced Loss Rates (FLRs) at the Pickering and Darlington plants, considered as separate plants and thus potentially resulting in a reward for progress made in one plant being partially offset by a penalty for a degradation of performance at the other plant.

- Establish a variance account for the DRP, with an incentive mechanism that is aligned with any cost and completion date incentives that are in place for the Engineering, Procurement and Construction (EPC) contractor and other key vendors.

- Provide for timely recovery of existing fixed costs for Darlington units while they are out of service; fixed costs attributable to the refurbishment would be placed in a deferral account for recovery after the units return to service.

<u>Hydroelectric Operations</u>:

- Establish a traditional price cap mechanism (Option H5) with a modest "x-factor" that encourages cost efficiencies without threatening the continued future availability of OPG's prescribed hydroelectric facilities;

- Retain the HIM (Option H1), with incentive payments that are proportionate to the benefits that are reflected in customer bills, thus retaining the existing sharing above a capped amount approach; and

- Continue the practice of after-the-fact reviews of OPG's performance during SBG conditions, making adjustments to a variance account if it determines that OPG could have reasonably taken actions to mitigate the impact of SBG conditions.

OPG Financial Performance:

- Implement an earnings-sharing mechanism (Option N6) that applies to the entirety of OPG's prescribed facility operations with a relatively broad deadband (e.g., plus or minus 250 basis points) around the authorized return and symmetrical sharing above and below the deadband;

- Incorporate a z-factor to account for the potential for the impact of extraordinary exogenous events that are beyond the control of OPG management and were not foreseen when the plan was implemented; and

- Implement an off-ramp that terminates the IRM should OPG's financial performance be so impaired as to threaten OPG's ability to attract capital to finance its construction budget on reasonable terms.

Power Advisory acknowledges that these recommendations represent a departure from past practices either in Ontario or elsewhere, and particularly with respect to the recommendation to implement a target revenue requirement under Option N2 that incorporates cost and production efficiencies in years 2 through the end of the IRM term. These recommendations attempt to reflect the unique role of OPG's assets and its position with the Province of Ontario as its sole shareholder. This also presents certain challenges as ideally management and employee incentives should be aligned with those of the organization and in this case, Ontario and its customers. This is harder to achieve in a public organization than in a private firm. We therefore recommend that OPG review its compensation practices to determine if this alignment can be improved, but accomplished in a manner that will be acceptable to the Province and its citizens.

6.3 Implementation

Implementation of these recommendations will require an updated benchmarking study that is designed to support the implementation of the nuclear N2 option as well as a more traditional productivity study to support a price cap for hydroelectric operations. Substantial controversy is likely to be involved with respect to the benchmarking study and Power Advisory would recommend that a scoping exercise be conducted that provides for an opportunity for comment by the Board and stakeholders.

The performance of a hydroelectric productivity study may encounter the same data challenges as beset efforts to perform an analogous study for Ontario's electric distributors but also introduce validity concerns due to the unique nature of the OPG hydroelectric operations relative to comparative operations. Given the relatively modest level of concern that has been expressed regarding the potential for cost efficiencies for OPG's hydroelectric operations, a modest x-factor based on judgment and any supporting analyses that can be provided by OPG, including benchmarking results, may suffice.

Under any IRM, Power Advisory recommends a formal reporting process that improves the transparency of key performance metrics in both the nuclear and hydroelectric operations. These metrics certainly include UCF and FLRs for nuclear operations, EAFs for hydroelectric operations, and cost benchmarks for both operations.

As OPG is owned by the Province, it is appropriate to enhance this transparency and accountability by broadcasting key performance metrics to the public, along with sufficient explanation to provide for proper interpretation. Such communications could clearly describe major capital projects such as DRP, the costs and benefits of these projects, and steps that are being taken to efficiently manage the projects. These communications could serve as a mechanism to explain the merits of any employee and management incentives that are implemented as part of a broader IRM approach.

I. INTRODUCTION

Q. Please state your name, business address and present position for the record.

A. My name is Robert C. Yardley, Jr.; my business address is 107 South Street, 3A Boston MA 02111. I am the founder of Waterstone Group, which provides advisory services to public and private energy organizations with particular expertise in regulatory policies that pertain to the transition to competitive wholesale and retail energy markets.

Q. Please describe your educational and professional background.

A. A statement of my education and experience is attached to my testimony as Attachment 1. As indicated in this attachment, I have worked in the energy industry for my entire 20-year professional career. For two of those years (1991-92), I served as Chairman of the Massachusetts Department of Telecommunications and Energy (which was named the Department of Public Utilities at that time).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Southern Gas Company's ("Southern's" or "the Company's") proposal to implement an alternative rate or performance-based ratemaking ("PBR") plan. I have been working as an advisor to Southern since January of this year to develop a PBR proposal. Specifically, I was asked by the Company to help them develop a proposal that would provide tangible benefits to Southern's customers, advance the policy objectives of the Commission, and provide Southern with incentives to operate efficiently and grow while preserving the Company's quality of service. I believe that Southern's PBR proposal accomplishes these objectives in a manner that provides an appropriate balance between the interests of Southern and its customers.

My testimony will provide an overview of the plan, the details of the rate aspects of the plan, and the reasoning relied upon to develop the plan. I will also provide an overview of the Service Quality Plan ("SQP"), which is a key component of Southern's proposal. In so doing, I will describe the importance of a SQP as an element of a PBR proposal and the process that Southern used to develop the specific service quality measures.

Q. Are any other witnesses providing testimony that addresses Southern's PBR proposal?

A. Yes. Mr. Sal Ardigliano and Mr. Peter Loomis present testimony which describes the SQP in much greater detail, including a discussion of each of the specific measures that are being proposed by Southern. These individuals have responsibility for the operational areas of the Company that provide the customer services that the SQP will measure.

Q. How is Southern's PBR proposal related to its proposal in this application to increase its rates and charges?

A. Southern is filing a traditional rate case in this application to address a revenue deficiency. The rates established in the rate case portion of this proceeding will serve as the "cast-off" rates for purposes of implementing the PBR plan.

There is one important distinction, however. As indicated in the Application, Southern reserves the right to decline to implement the PBR plan should the likely revenue path established by the Commission order prove to be untenable. This option is made necessary by Southern's agreement to relinquish its right to file a rate case during the term of the plan. It is certainly Southern's intention to avoid this result and the PBR proposal has been developed with that objective in mind.

Q. What will happen if Southern declines to implement the PBR plan?

A. If Southern declines to implement the PBR plan, the current regulatory rate setting practices would continue to apply. Thus, Southern would be subject to an excess earnings review if its earned return on equity exceeded its allowed return on equity by greater than 100 basis points for six consecutive months. The

Commission would also require Southern to file for a Financial Review after four years if Southern had not filed a rate case in the interim. Thus, the PBR plan is truly intended and perhaps best considered as an "alternative" approach to rate setting over the next four years for the Commission to consider.

Q. How is your testimony organized?

A. In the following section, I will present a summary of Southern's proposal and my proposed findings. That will be followed by a discussion in Section III of background information that Southern considered in developing its proposal, including relevant precedent in the State of Connecticut. The details of Southern's proposal are described in Section IV. A summary of the merits of the proposal is presented in the final section of my testimony.

II. SUMMARY OF SOUTHERN'S PBR PROPOSAL

Q. Please provide a summary of Southern's proposal.

A. Southern is proposing to freeze its base rates for the next four years at the levels to be established in this proceeding, with the following caveat: if the Commission agrees that an acceleration of Southern's bare steel services and cast iron mains replacement program is desirable, Southern will increase its expenditures in this area by as much as $3 million per year over and above the $5 million of annual expenditures that are reflected in the current capital plan. This option would have a modest impact on customer rates.

Southern is also proposing to implement an Earnings Sharing Mechanism ("ESM") with 50-50 sharing of any earnings that exceed Southern's allowed return on equity outside of a 100 basis point collar or deadband. Sharing with customers will occur on the upside only; Southern proposes that its shareholders absorb any earnings shortfall on the downside.

In order to demonstrate an ongoing commitment to service quality, Southern is proposing to implement a Service Quality Plan (“SQP”) as an integral part of the PBR proposal. Under the SQP, Southern will submit periodic information to the Commission regarding its service quality based on five separate measures. Southern is not proposing to institute any financial rewards or penalties as part of its SQP.

Finally, as is common in PBR proposals, Southern is proposing a limited set of rate relief conditions under which rates would either be adjusted (to reflect the impact of a limited set of pre-specified “exogenous” events) or reopened (to address any serious deterioration in Southern’s financial condition).

Q. How does the proposal provide tangible benefits to Southern’s customers?

A. The proposal provides rate stability and certainty to Southern’s customers over a four-year period, while providing an opportunity to share significantly if Southern is able to increase its earnings as a result of operating more efficiently or successfully competing to attract new load. Second, the SQP provides the Commission with an assurance that Southern’s commitment to providing service of the highest quality will continue and provides the Commission with a formal mechanism to track its performance in this area. Third, the bare steel/cast iron replacement option, if implemented, will improve the safety and reliability of Southern’s distribution system.

Q. Does the Commission have the statutory authority to approve Southern’s proposal?

A. Yes. It is my understanding, based on a review of Connecticut General Statute Section 16-19kk(c) and consultation with Southern’s legal staff that the Commission has the authority to approve Southern’s proposed alternative rate plan.

Q. Please summarize the findings that you propose be adopted by the Commission.

A. I propose that the Commission find that:

(1) it has the statutory authority to approve a PBR plan for a natural gas distribution company;

(2) Southern's proposal will provide tangible benefits to customers and is in the public interest;

(3) Southern's PBR plan be approved as proposed by Southern without modification;

(4) Southern's rates over the term of the PBR plan will conform to the principles and guidelines set forth in Connecticut General Statute, Section 16-19e; and

(5) The plan for periodic review of the PBR shall be in lieu of the requirements of Connecticut General Statute, Section 16-19a(a) as permitted by Section 16-19a(b).

III. BACKGROUND ON PBR AND CONNECTICUT PRECEDENT

Q. Has the Connecticut DPUC approved PBR plans for other utilities?

A. Yes. United Illuminating Company ("UI") and Southern New England Telephone Company ("SNET") are currently operating under multi-year PBR rate plans. While the circumstances faced by these utilities are distinct from those facing Southern, the Commission's orders in these cases provided useful guidance to Southern in developing its own proposal.

The UI precedent is the most relevant of the two cases. This is due in part to the fact that both the electric and natural gas distribution industries are in the early stages of a transition toward retail competition. UI's proposal is also responsive to its need to dispose of its generation assets and the potential for stranded costs associated with its nuclear generation facilities, a circumstance that is not shared by Southern. However, the UI precedent did provide the Commission's perspective on the importance of providing tangible benefits to customers and the role of service quality monitoring during the term of the plan. Most importantly, it indicated that the Commission is willing to consider and approve an alternative approach to rate setting that recognizes the potential for customers and shareholders to benefit from improved operating efficiencies.

The SNET precedent has much less direct relevance because of the fact that the industries are radically different, particularly with respect to the role that emerging technologies play in the telecommunications industry. However, the SNET experience did provide some guidance in developing Southern's SQP.

Q. Have other natural gas distribution utilities in this region implemented PBR plans?

A. Yes. Within the last few years, PBR plans have been approved for Boston Gas Company, Bay State Gas Company and Providence Gas Company. Additionally, many of the New York distribution companies have been operating under multi-year rate settlement agreements which operate in many respects as PBR plans.

Each utility's PBR proposal reflects its unique set of financial and operating circumstances as well as policy guidance that has been provided by its state regulatory agency. Nonetheless, these plans are informative because they provide a sense of how rate and service quality issues have been addressed by other utilities and their regulatory commissions.

Q. Why have state regulatory commissions and utilities expressed an interest in PBR in recent years?

A. I believe that there are two primary and closely-related factors that are driving the interest in PBR and multi-year rate agreements. First, there has been an interest over the past decade in improving the incentives that utilities have to lower costs and thereby lower customer bills. In New England, this interest began as the region slowly emerged from the economic slowdown at the end of the 1980s and has not abated. While the traditional rate case approach served regulators well for many years, there was a growing interest in trying "incentive-based" approaches. At first, many of the incentive programs were developed to provide utilities with an incentive to invest in conservation and load management programs or to operate their generating facilities more efficiently. However, as rate pressures grew, commissions and utilities began to focus on broader incentives.

The second and related factor is the introduction of retail competition. With the introduction of retail competition, utilities recognize the need to be more competitive. Lower rates and higher quality service each contribute to this objective. In addition, as a result of legislative and regulatory policies, there is a much finer distinction between activities that will continue to be regulated and those that will be provided by utilities and other firms in a competitive environment. The restructuring effort frequently includes provisions that encourage regulatory agencies to consider PBR for those activities that continue to be regulated.

There is also a recognition by both utilities and regulatory agencies that the introduction of retail competition requires an enormous amount of work on both policy development and business process redesign and implementation. Time and resources devoted to litigation of traditional rate cases and earnings reviews might be more productively spent on the challenge of ensuring that customers will benefit from retail competition.

Q. Is PBR a radical departure from the traditional regulatory rate setting practices?

A. PBR is not really a radical departure from traditional regulatory rate setting practices. In particular, the goals of regulation have not changed dramatically. However, PBR does represent an alternative means of pursuing those goals and can result in greater efficiency and lower rates to customers.

IV. DETAILED REVIEW OF SOUTHERN'S PBR PROPOSAL

Rate Plan and Term

Q. How will customer rates be set during the term of the PBR plan?

A. Southern is proposing to freeze its base rates through December 31, 2003 (or approximately four years depending on the effective date of the rates established in this proceeding). Rates will be frozen at the levels to be established in this proceeding. Southern is also proposing to accelerate its cast iron main/bare steel service replacement program as an option for the Commission to consider. This option, which will be described later in my testimony, would have a modest impact on rates.

Q. Why is Southern proposing a four-year term for the plan?

A. A four-year term reflects a balance between Southern's desire to provide its customers with the benefits of an extended rate freeze and the considerable operating uncertainties that Southern and other distribution companies will face over the next four years. These uncertainties are primarily attributable to the changes in the industry brought about by the transition to a competitive retail market. Southern's proposal has been structured to insulate Southern's customers from these risks. In particular, under Southern's proposed ESM structure, Southern's shareholders absorb all of the downside earnings risk while providing customers with the ability to share in upside earnings. The risk associated with Southern's rate freeze and ESM commitments increases as the term of the PBR plan increases.

Earnings Sharing Mechanism

Q. Why is Southern proposing an Earnings-Sharing Mechanism?

A. ESMs are frequently included as part of PBR plans because they provide an automatic mechanism for customers to share in benefits that result from the types of activities that the PBR plan is intended to encourage. In Southern's case, the mechanism as proposed is assymetrical; that is, it provides customers with the ability to share in cost savings or revenue increases that contribute to an increase in earnings, while insulating them from the impact of a deterioration in earnings during the term of the rate plan. Southern believes that this is a much more efficient regulatory approach as it encourages efficient behavior and is also more administratively efficient than the current regulatory approach.

Q. How will the ESM work?

A. Southern's return on equity will be calculated annually, based on a fiscal year basis. Southern's fiscal year is the twelve months ending September 30th of each year. If the earned ROE, using the DPUC approved cost of capital method, is either below the allowed ROE or within a 100 basis point "deadband" above the allowed ROE, no adjustment to rates will be made. However, if the earned ROE exceeds the allowed ROE by greater than 100 basis points, the "excess" earnings will be divided equally between customers and shareholders. Any resulting rate decrease would be applied to customer bills during the following year.

Q. How will the ESM be calculated in the initial year if rates go into effect after January 1, 2000?

A. The ESM will be calculated based on the twelve months ended September 30, 2000, even if the rates established in this proceeding go into effect after January 1, 2000. The ESM calculation will be based on a three-month period from October 1, 2003 through December 31, 2003 at the conclusion of the rate plan.

Q. How does the ESM compare with the Commission's examination of Southern's earnings under the current regulatory review process?

A. Southern has structured the ESM component of the PBR plan to be similar in many respects to the current earnings review process. For example, under the current process, an excess earnings review is not triggered until Southern earns at least 100 basis points above the allowed ROE for six consecutive rolling 12-month periods. Furthermore, no provision is made to increase rates should the earned ROE fall below the allowed ROE unless Southern files for an increase in rates.

Under the ESM proposal, Southern would continue to provide the Commission with the information required to verify its earned ROE each month based on a rolling twelve-month historical period. As indicated above, the ESM calculation would be based on the earned ROE calculated for the twelve months ended September 30th of each year.

The more important distinction between the current and proposed approaches is that there will be no need for the Commission to conduct a litigated proceeding to examine excess earnings and to determine whether the overearnings were likely to continue into the future or whether they would benefit customers. It is therefore quite conceivable under Southern's proposal that customers would share in earnings above the allowed ROE even if it was unlikely that the Southern would continue to earn at such levels. The "automatic" nature of the ESM would preclude Southern from making the claim that the earnings were the result of extraordinary circumstances.

Q. How will Southern's customers benefit from the ESM mechanism as it has been structured by Southern?

A. The ESM mechanism provides Southern's customers with an effective and administratively efficient mechanism to share in benefits that are generated from activities that either reduce costs or increase revenues. At the same time, they are not only insulated from sharing on the downside, but are protected from a rate increase for a minimum of four years, unless Southern experiences financial hardship that results from extraordinary circumstances.

Q. Why is the ESM superior to the existing approach?

A. The ESM approach is more likely to lead to behavior that generates long-term benefits to customers and provides for an administratively efficient mechanism of sharing the benefits with customers. Southern believes that the time that is currently devoted to the excess earnings reviews by all parties can be spent more effectively if devoted to other important activities.

Service Quality Plan

Q. Why did Southern decide to include a SQP as part of its proposal?

A. State regulatory commissions throughout the country have expressed a concern that utilities operating under a PBR mechanism may have an incentive to cut costs in a manner that results in a deterioration of the quality of service provided to customers. A SQP provides a means for regulatory commissions to monitor performance in this area and sends a message to customers and the utility that service quality should not be allowed to suffer as utilities pursue more efficient operations. Southern's commitment to providing service of the highest quality has not changed and it believes that incorporating a SQP as a key element of its PBR proposal is entirely appropriate.

In fact, this commitment and its relationship to the goal of operating efficiently is reflected in the language used to express one of the Company's key strategic objectives:

- **Aggressively control operating and maintenance expenses to maximize efficiency and reduce the cost of service, while maintaining the existing high level of safety and quality of service.**

Q. What were the Company's overall objectives in developing the SQP?

A. Southern's development of the SQP was guided by the following objectives:

(1) each measure should be of high importance to Southern's customers, the DPUC, and to Southern;

(2) the ability to perform under each measure should be largely within Southern's control and not driven by outside factors beyond Southern's control;

(3) implementation efforts required to collect and report the measurement should not be significant or require a costly investment in new business processes or systems; and

(4) the data to be reported to the Commission should either be publicly available or able to be provided under a protective order.

In the UI order, the Commission directed UI to develop between four and ten measures of service quality. In preparing its SQP, Southern wanted to have at least four measures but did not otherwise constrain the evaluation process to arrive at a specific number of measures, and selected all measures that it believes are appropriate.

Q. How many measures are included in Southern's proposal?

A. Southern is proposing to implement five service quality measures:

(1) ***Customer Satisfaction***: as represented by a statistically valid survey instrument that measures the satisfaction of customers that have recent contact with the Company, including its customer service personnel and field technicians (the survey instrument currently measures the performance of the Company based on 34 distinct "characteristics");

(2) ***Call Center Responsiveness***: as represented by the average time in seconds that a customer waited in queue for a resource capable of addressing their inquiry, which could be an agent or an automated process;

(3) ***Suspected Gas Leak Call Responsiveness***: as represented by the percentage of calls that are reported as suspected gas leaks on a customer's premises that are responded to within DPUC Staff guidelines;

(4) ***Service Call Responsiveness***: as represented by the ability of the Company to meet scheduled 4-hour appointment windows for four types of service calls (no-heat service calls, turn-on service calls, no hot water service calls, and legal meter changes); and

(5) ***Billing Based on Actual Meter Reads***: as represented by the ability of the Company to provide customers with bills based on an actual meter reading, expressed as a percentage of customer bills that are generated based on an actual meter reading.

Each of these measures is described in considerable detail in the testimony of Mssrs. Ardigliano (measures 2, 3 and 4) and Loomis (measures 1 and 5) which includes the specific definition of each measure, a proposed benchmark against which future performance will be measured, and the information that will be reported to the Commission during the term of the PBR plan.

Q. How did Southern decide which measures to include in its proposal?

A. Southern expended considerable time and effort to identify potential measures, subject them to an evaluation process to develop a short-list of the most promising measures, and refine the definitions. The process involved individuals from throughout the organization including the senior management team, but particularly those that are responsible for the customer care activities.

Although service issues in the natural gas industry are different in some significant respects from the electric industry, the Commission's guidance provided in its order on the United Illuminating PBR proposal was also helpful.

Finally, the Company examined the SQPs from other LDCs in the region to identify the measures that have been implemented by other utilities.

Q. What types of measures were considered but not included in the final list of proposed measures?

A. Southern considered several measures that are not included in its proposal. For example, the Company considered measures that would directly measure the safety of its operations. These included both an employee safety measure (based on lost work time) and a community safety measure (based on damage to Southern's mains and services for which it is responsible). These were rejected as either being less important from the perspective of customers (employee safety) or already subject to appropriate Commission oversight authority (community safety).

The Company also considered measures that would address the satisfaction of retail marketers as customers but concluded that it is still premature to define and implement such a measure at this time, even on a pilot basis.

The measure that received the greatest consideration but was ultimately excluded from the SQP proposal was a customer complaint measure that would be based on complaints received regarding Southern's performance by the DPUC.

Q. Why did Southern decide not to propose the DPUC-based customer complaint measure at this time?

A. There are legitimate concerns regarding such a measure from both the DPUC and Company's perspective. From the Company's perspective, it believes that it would be necessary to work with the DPUC to develop a data collection process that was consistent with the existing DPUC Scorecard process, but which provided for a more precise and perhaps stringent definition of calls which are logged as "complaints". Under the current Scorecard process, there are some calls which are more appropriately characterized as "inquiries" regarding

Southern's billing or other practices than as "complaints". This may be appropriate for the purposes of preparing the DPUC Scorecard, but may not be appropriate for purposes of a SQP measure.

More importantly, Southern believes that the Customer Survey measure, if properly designed and conducted, is a superior way to measure customer attitudes toward the Company and to evaluate their satisfaction with interactions that they have had with Company personnel.

Q. Is the Company aware that the DPUC has expressed reservations about the reliance of customer survey instruments as a service quality measure?

A. Yes. UI, in its initial PBR proposal, proposed a measure that was based on a customer satisfaction survey. In rejecting the use of a survey by UI, the Commission raised concerns regarding the ability to make the results available to the public, the weighting scheme to be applied to the responses to various survey questions, and the general reliance on survey instruments for regulatory oversight.

Q. What steps has Southern taken to address these concerns?

A. Southern's proposed survey measure, as discussed in the testimony of Mr. Loomis, addresses some of the Commission's concerns. Southern proposes to make the survey instrument and summary results publicly available. In addition, there is no complicated weighting scheme – the scoring is based on a simple average of the responses to 34 questions in three categories:

- General Company ratings (13 characteristics);
- Office/Customer Service Personnel ratings (8 characteristics); and
- Field Technician ratings (13 characteristics).

In Southern's case, the customer survey measure is proposed in addition to four other more specific customer satisfaction measures, which also distinguishes the proposal somewhat from UI's initial proposal.

In addition, Southern proposes to work with the Commission Staff to continue to improve its survey instrument in an endeavor to make it acceptable for both internal and regulatory purposes. Southern has recently completed its second annual customer survey which was designed and conducted by the Center for Research and Public Policy, a firm that is respected as an independent and eminently qualified survey firm. The Center for Research and Public Policy counts both regulatory agencies and utilities among its clients.

If the Commission agrees that the customer survey instrument has potential as a regulatory oversight tool, Southern would propose to involve the Commission Staff in its planning efforts for next year's survey. Thus, Staff would be provided with an opportunity to meet with survey consultant prior to the conduct of the survey to address concerns that it may have regarding the design of the instrument, conduct of the survey, and interpretation of the results.

Q. Why is Southern proposing to exclude financial rewards and penalties at this time?

A. Southern has decided not to propose rewards or penalties at this time for several reasons. These include:

- Southern's PBR plan does not provide for annual price increases; many proposals that provide for price increases also have a SQP with a graduated penalty structure;

- the reasoning applied by the Commission in rejecting UI's proposed reward/penalty structure also applies to Southern, namely, that Southern's objective should be to maintain its existing high quality of service during what is expected to be a period of transition to a competitive market structure; and

- as its first PBR plan, Southern has tried to keep the proposal relatively simple; it makes more sense to gather service quality measure data for some period, before applying financial rewards and penalties.

Most importantly, even without financial rewards and penalties, the SQP provides the Department with the ability to monitor quality of service during the term of the plan and assure itself that service quality will not be adversely impacted by the implementation of Southern's PBR proposal.

Cast Iron Main/Bare Steel Service Program Acceleration Option

Q. Why is Southern offering to accelerate its cast iron/bare steel replacement program?

A. Southern believes that an acceleration of its cast iron/bare steel replacement program is in the public interest as it improves the safety and reliability of its system, <u>but only if</u> it can be accomplished with an acceptable rate impact.

Over the past several years, Southern has been replacing approximately 855 services and 7 miles of mains per year in its replacement program. The factors that have limited a more aggressive replacement program are concern over revenue impacts (as these "replacement" investments generally do not contribute to increased throughput) and Southern's ability to manage the engineering construction effort.

Q. Does the rate freeze reflect any capital expenditures in this area?

A. Yes. The rate freeze commitment reflects a continuation of Southern's program to replace the cast iron mains and bare steel services on its system by investing approximately $5 million per year. In order to maintain this level of non-revenue producing investment and avoid an earnings deficiency, Southern must either decrease costs or increase net revenues by approximately $1.0 million each year. However, Southern is proposing to accelerate this program for the term of the rate plan by increasing the annual expenditures by as much as 60 per cent or $3 million per year if the Commission authorizes recovery of the depreciation, taxes and return on investment associated with this incremental investment.

As the investment required per service and per mile of main can vary significantly, Southern proposes that a cap on incremental expenditures be set at $3 million per year to be divided between service replacements ($1.75 million) and main replacements ($ 1.25 million) and that the total expenditures be capped at $8 million per year. The split between service and main replacements maintains the emphasis on these investments that is in the current replacement plan. Although Southern may have to use some overtime work to handle the engineering and construction management effort, the Company believes that it can accommodate this level of acceleration in the program.

Q. What increase in customer rates would be required to accommodate the acceleration of the bare steel/cast iron replacement program?

A. An increase of $3 million in Southern's program would result in an increase in total revenue requirements of approximately $0.6 million per year. In percentage terms, average margins would increase approximately 0.5 % per year and total rates would increase by approximately 0.3% per year to accommodate this level of expenditures. It is important to note that potential acceleration of this program is facilitated by the commitment to freeze rates based on an assumption that replacement investments continue at their current level. In other words, if other areas of Southern's operations were likely to contribute to a need to increase rates, the rate impact attributable to accelerating these investments may no longer be acceptable.

Rate Relief Conditions

Q. Please describe the conditions under which the plan can be revisitied.

A. There are two categories of "exogenous" events that will require that the PBR plan to be revisited by the Commission. The first of these are events that require that rates be recalculated. There are also conditions under which the plan should be terminated.

Q. What factors will lead to a need to recalculate rates under the plan?

A. There are certain events that cannot be anticipated by Southern or by the Commission that would require rates to be recalculated (either increased or decreased) during the term of the plan if they have a material impact on Southern. These are:

(1) A legislated change in a federal or state tax rate;

(2) A change in a tax law or accounting standard;

(3) A change in a law or regulation;

(4) Environmental clean-up costs which require a current expense;

(5) Litigation involving Southern that results in either a significant windfall gain or loss (e.g., resolution of an environmental remediation or property tax suit); and

(6) An "Act of God".

Q. Are these factors typical of PBR plans?

A. Yes. This is a fairly standard and limited list of conditions under which rates would be recalculated during the term of a PBR plan.

Q. What factors will led to a reopening of the plan?

A. The plan would be terminated at Southern's option, or in effect, Southern would be required to file a new rate case if one of the following conditions occurs:

(1) Either the rate of inflation increased by 150% or the prime rate increased by 100% or more from the levels that exist today (2.1% for inflation as measured by the CPI, and 7.75% for the prime rate);

(2) The 30-year treasury rate increases by 50% or more from its current rate of 5.96 %; or

(3) Southern's earned ROE falls below its allowed ROE by 200 basis points or more.

The third condition is fairly standard in PBR plans. The first two conditions are really less direct measures of the same consequence, namely adverse economic conditions that result in a significant deterioration in Southern's financial condition. These conditions were included in Southern's 1993 rate settlement, approved by the Commission in Docket No. 93-03-09.

Q. When would Southern make compliance filings under the PBR plan?

A. Southern would make annual compliance filings under the plan to provide information on both its financial performance and SQP measures. The impact of the earnings sharing mechanism and, if approved, accelerated bare steel/cast iron replacement program, would be calculated on a calendar year basis.

The resulting change in rates would be applied over the next twelve months beginning on the anniversary date of the effective date of rates to be established in this docket. Any rate increase or decrease would be applied to the volumetric portion of the rate design for all firm customers and would be shown separately on the bill. However, if the impact is relatively minor, Southern may propose to implement the resulting change over a much shorter period, and perhaps during a single billing period if the impact is minor.

Q. Why is Southern reserving the right to decline to implement the PBR plan?

A. Southern is reserving the right to decline the PBR plan because it is the only reasonable recourse available to the Company should the Commission modify the plan in a manner that is untenable to the Company. Having said that, it is important to note that the Company is making this proposal because it believes strongly that it serves the interests of its customers and shareholders, and will be viewed positively by the Commission as well.

The direction that I received from Southern was to assist the Company in developing a proposal that would be acceptable to the Commission without modification. I believe that this proposal accomplishes this objective, but I do not presume to substitute my own judgement for the Commission's in this regard.

V. SUMMARY AND CONCLUSION

Q. Please summarize your recommendation that the Commission approve Southern's PBR proposal without modification.

A. In summary, Southern's PBR plan should be approved because it accomplishes the following objectives:

(1) it provides rate stability and certainty to Southern's customers over a four-year period;

(2) it insulates Southern's customers from many of the risks that will be facing distribution companies over the next four years;

(3) it provides an opportunity for customers to experience lower rates if Southern is able to increase its earnings as a result of operating more efficiently or successfully competing to attract new load;

(4) it provides Southern with a clear incentive to pursue activities that result in operating efficiencies or profitable new load;

(5) the bare steel/cast iron replacement option, if implemented, will improve the safety and reliability of Southern's distribution system;

(6) the SQP provides the Commission with an assurance that Southern's commitment to providing service of the highest quality will continue and provides the Commission with a formal mechanism to track its performance in this area; and

(7) it provides Southern and the Commission with some additional time and resources to devote to important unbundling issues.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.