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VIA *RESS* FILING AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli

Re: Ontario Energy Board Consultation on Incentive Regulation for Ontario Power Generation
Submission of the Power Workers' Union - October 1, 2012
Ontario Energy Board File No. EB-2012-0340

Please find enclosed the Submissions of Power Workers' Union in connection with the above-noted proceedings.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

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cc: J. Kwik
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EB-2012-0340

Ontario Energy Board Consultation on

Incentive Regulation for Ontario Power Generation

Submission of the Power Workers' Union

October 1, 2012

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Incentive Regulation for Ontario Power Generation

PWU Submission

1 BACKGROUND

In a 2006 Ontario Energy Board ("OEB" or "Board") consultation (EB-2006-0064) on a methodology for the regulation of Ontario Power Generation ("OPG") the Board noted its preference for implementing a full incentive regulation ("IR") regime for OPG once an IR formula has been determined based on OPG's financial and cost data and concluded that a limited series cost of service ("COS") process should be used to determine the base payments for an IR plan:

> **However, the Board considers that a full incentive regulation regime is in this case better implemented once the parameters of the incentive regulation formula (i.e., base payments, productivity and cost inflation factors) have been determined by a review of OPG's financial and cost data. The Board has therefore concluded that a limited issues cost of service process should be used for determining the base payments for incentive regulation.**[1]

Subsequently the Board held COS reviews on OPG's 2008 and 2009 payment amounts application (EB-2007-0908) and on OPG's 2011 and 2012 payment amounts application (EB-2010-0008). In its decision on OPG's 2011 and 2012 payment amounts, the Board indicated that it remains convinced that an IR mechanism ("IRM") for OPG's payment amounts will be beneficial in the long term. The Board notes that, assuming a suitable IR design for OPG's payment amounts, the benefits would be those set out in the Board's Natural Gas Forum Report[2] including sustainable gains in efficiency, appropriate quality of service and an attractive investment environment:

[1] OEB. EB-2006-0064. Board Report - A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc., November 30, 2006. Page 1.
[2] OEB. RP-2004-0213. Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum. March 30, 2005. Page 22.

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

In its decision on OPG's 2011-2012 payment amounts the Board concluded that IR for OPG beginning in 2015 should be considered and provided for a review to consider IR in the context of OPG's unique circumstances.

However, the Board concludes that incentive regulation beginning in 2015 should be considered. To facilitate this, the Board will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG. This review may include options and preferences on the general type(s) of incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. This preliminary process to consider incentive regulation mechanisms in the context of OPG's unique circumstances will allow for input from OPG and all other interested stakeholders.[3]

Further, the Board stated its expectation for OPG to file an application, no later than the fourth quarter of 2013, for an IR plan to be in effect starting in 2015.

On April 20, 2012 the Board issued a report prepared by Power Advisory LLC ("PA report")[4] that set out IRM options for OPG's regulated nuclear and hydroelectric generation facilities. A stakeholder meeting was held on August 28, 2012 at which PA presented its options. OPG and OPG's expert consultant London Economics International LLC ("London Economics") also made presentations on IR options for OPG at the stakeholder meeting. In addition OPG's expert consultant Harbourfront Group, Inc. ("Harbourfront") made a presentation on the US state commissions' regulatory focus on nuclear generation performance standards.

[3] OEB. EB-2010-0008. Decision with Reasons. Ontario Power Generation Inc. Payment Amounts for Prescribed Facilities for 2011 and 2012. March 10, 2011. Page 156.
[4] Power Advisory LLC. Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets. April 20, 2012.

2 PWU POSITION

The Power Workers' Union's ("PWU") submissions on considerations of IR for OPG starting in 2015 are guided by its energy policy:

> **Reliable, secure, safe, environmentally sustainable and reasonably priced electricity supply and service, supported by a financially viable energy industry and skilled labour force is essential for the continued prosperity and social welfare of the people of Ontario. In minimizing environmental impacts, due consideration must be given to economic impacts and the efficiency and sustainability of all energy sources and existing assets. A stable business environment and predictable and fair regulatory framework will promote investment in technical innovation that results in efficiency gains.**

Regardless of the approach used in regulating OPG's regulated assets, the Board must provide for reasonableness, predictability and fairness in requiring OPG to achieve efficiency gains while avoiding irrational cost cuts that compromises the sustainability of OPG's facilities and service value. It is essential for the Board to ensure that OPG's pursuit of IR's economic incentives do not result in the compromise of public and employee health and safety.

In its EB-2010-0008 decision the Board noted that it is not aware of any IR plans that apply only to generators that might help in the development of a plan for OPG. In addition to the apparent absence of IR plans for generation-only utilities that might help evaluate the implications of IR options for OPG, there are other significant challenges and obstacles in the development of IR for OPG that must be addressed. Incentives for cost and quality performance can be powerful and a comprehensive understanding of how an IR plan can meet the desired objectives while addressing the challenges and obstacles is essential. In the absence of such insight, there is a serious risk that the incentives may result in inadvertent deterioration of quality performance and compromise the sustainability of the regulated assets that OPG has stewardship over on behalf of the people of Ontario. With OPG's regulated assets providing a significant portion of Ontario's low cost baseload generation, a reduction in the production from these assets will result in higher electricity prices if higher-priced generation supply is required to make up for the lost production. This outcome would be detrimental for electricity customers and the economy, and is not in the public interest.

Addressing the challenges and obstacles precludes the implementation of a simple IR approach for OPG and would require a complex IR framework. It is not acceptable, even as a starting point, to settle for a simplistic IR framework that arises from the lack of real world precedents of IR for generation-only utilities, the limits of the Board's own IR experience, and the Board's limited familiarity with the costs of OPG's complex operations. Doing so exposes OPG and consumers to the risks of unanticipated perverse outcomes including nuclear safety concerns. Given the improbability that these challenges will be overcome and the potential risk to safety performance it would be imprudent to compel OPG to embark on a broad IR plan in 2015, if ever.

In this submission the PWU describes essential components of an IR framework followed by discussions on the challenges and obstacles of implementing an IR framework for OPG, including major planned OPG capital projects, anticipated changes in Ontario's energy market, and the ongoing workforce renewal. In addition the PWU discusses uncertainties that are not in the control of OPG that present challenges to the use of a Total Factor Productivity ("TFP") cap mechanism. Other issues discussed include the U.S. experience with IR for utilities with nuclear generation, the OEB's paucity in its IR experience, the lack of data required to inform the development of an appropriate TFP cap mechanism, and the importance of including quality performance (e.g. safety performance) standards and incentives in IR.

Based on the above discussions, comments are provided on the discussions and options on IR for OPG forwarded in the PA report and in OPG's, London Economics' and Harbourfront's presentations made at the stakeholder meeting.

The PWU supports OPG's proposal presented at the stakeholder meeting that its nuclear assets continue to be regulated on COS regulation until Darlington refurbishment is completed and Pickering is out of service. However, in the PWU's view, given the many challenges and obstacles discussed in this submission, implementation of IR for OPG nuclear is questionable even beyond the completion of these significant capital projects.

3 ESSENTIAL COMPONENTS OF AN IR FRAMEWORK

In this section essential components of an IR framework are described that provides the context for the PWU's comments on IR for OPG's regulated assets.

IR is an alternative regulatory approach to traditional COS regulation that is intended to provide more powerful incentives for regulated companies to increase efficiency, improve quality performance, and pursue innovation.

As OPG noted at the stakeholder meeting and PA notes in its report, OPG's business plan is based on a top-down budgeting process that incorporates significant performance improvement targets in the four cornerstone value areas of safety, reliability, human performance and value for money that is embedded in its approved rates. In considering IR for OPG, its business plan performance targets implicit in base rates must be considered to avoid unrealistic expectations that are likely to result in unexpected, undesirable outcomes.

As the PA report notes, IR can be broad-based or targeted. Price cap and revenue cap mechanisms are examples of broad-based mechanisms. Targeted approaches focus on a narrow set of activities and encourage specific behaviour with respect to those activities.[5]

PA uses a price cap mechanism to describe a broad-based IR mechanism. Under price cap regulation the regulator typically sets an initial price ("P_0" or "baseline") through COS regulation. P_0 is then adjusted annually, over the term of the IR plan, for inflation and a target productivity factor (X). The inflation index should represent the inflationary pressures that will impact the utility's costs. This is the typical IR TFP cap mechanism.

According to Paul L. Joskow (2005) P_0 and X are developed based on a review of the utility's cost efficiency, current capital rate base (adjusted for depreciation), forecasts of future capital additions required to provide target levels of service quality, depreciation rates, estimates of the cost of debt and equity capital, and other

[5] PA Report, Pages 31-32.

variables.[6] Historically the choice of P_0 and X was driven by the notion that the regulated firms should be given some time to achieve reductions in operating costs to the efficient benchmarked level, leading to a relatively higher initial value for P_0 and a value of X that brings operating costs to efficient levels over the period the price cap is in effect. Because the overall price covers both capital and operating costs, the ultimate value of X depends on both the target cost efficiency improvements and the forecast carrying charges on the existing rate base plus carrying charges on allowed levels for future investments over the IR plan period.[7]

Joskow[8] points out that cost is only one dimension of a utility's multi-dimensional performance. Utility performance also includes "quality" dimensions (e.g. safety performance) and there are inherent trade-offs between cost and quality. For example, quality performance delivered by electricity distributors (e.g. frequency of outages, duration of outages) may deteriorate under price cap regulation because utilities may be willing to cut corners or even eliminate certain services. Accordingly, a regulatory framework that includes incentives for cost efficiency, of necessity must include incentives for quality performance to mitigate any urge on the part of the regulated entity to cut costs at the expense of quality performance. Targeted incentives are often applied by defining service quality performance standards and imposing penalties on the utility if the standards are not met.

In the PWU's view, in the case of generation, a quality performance metric that needs to be included in the IRM framework is safety performance. The PWU submits that the US Nuclear Regulatory Commission's ("NRC") concerns with regard to US state commissions' Nuclear Performance Standards described by Harbourfront at the stakeholder meeting, and discussed in section 5.1 below, point to the essential need for safety performance metrics in a nuclear IRM framework. In its presentation at the stakeholder meeting Harbourfront indicated that many U.S. commissions have

[6] Joskow, Paul L. MIT. Incentive Regulation In Theory and Practice: Electricity Distribution And Transmission Networks. Center for Energy and Environmental Policy Research. 05-014. September 2005. Page 38.
[7] Joskow, Paul L. MIT. Incentive Regulation In Theory and Practice: Electricity Distribution And Transmission Networks. January 21, 2006. Page 23.
[8] Ibid. Page 16.

frequent communications with staff at nuclear plants on costs and performance and that commissions either have qualified staff or retain nuclear expert consultants. Therefore IRM for OPG nuclear would require the Board to have nuclear experts on staff and/or retain expert consultants.

Another essential component of an IR framework is a mechanism such as an earnings sharing mechanism that will mitigate the risk of a productivity factor that may be too high or too low.

The PWU submits that the efficiency gains to be achieved over the IRM period assumes that the environment and the conditions that a regulated entity operates under at the time the IRM baseline is set are similar relative to the environment and operational conditions that would be expected over the time the IRM is applied. IRM requires that the regulated entity operates in a steady state environment. This is supported by London Economics following statement made at stakeholder meeting:

> **Theoretical underpinnings of a TFP-based price cap are generally fulfilled only in a steady state environment, where the regulated utility has matured and is facing steady state operations consistent with long run dynamics (e.g. capital expenditure that is consistent with depreciation expense on existing assets)**[9]

In addition, a factor that will account for unanticipated or extraordinary events (i.e. Z factor) that are not in the control of the utility needs to be included in an IR framework.

Furthermore, it must be recognized that the implementation of an IRM relies on information gathering, auditing and accounting requirements that are typically associated with traditional COS regulation. In reviewing IR theory and practice, Joskow (2005) observed:

> **Incentive regulation has been promoted as a straightforward and superior alternative to traditional cost of service or rate of return regulation. In practice, incentive regulation is more a complement to than a substitute for traditional approaches to regulating legal monopolies. In some ways it is more challenging. Whether the extra effort is worth it depends on whether**

[9] London Economics International LLC. Considering Incentive Rate Making Options for OPG's Prescribed Generation Assets Presentation at the Stakeholder Meeting hosted by the Ontario Energy Board. August 28, 2012. Page 5.

the performance improvements justify the additional effort. Incentive regulation in practice requires a good accounting system for capital and operating costs, cost reporting protocols, data collection and reporting requirements for dimensions of performance other than costs. Capital cost accounting rules are necessary, a rate base for capital must still be defined, depreciation rates specified, and an allowed rate of return on capital determined. There are still comprehensive rate cases required to implement "simple" price cap mechanisms. Planning processes for determining needed capital additions are an important part of the process of setting total allowed revenues going forward. Performance benchmarks must be defined and the power of the relevant incentive mechanisms determined. The information burden to implement incentive regulation mechanisms well is similar to that for traditional cost of service regulation.[10]

It is clear that IR is not simple and if the Board is determined to regulate OPG using IR, the Board must be prepared to properly address all the complexities and challenges in doing so. The unintended and unanticipated consequences of flawed incentives on cost and quality performance can be significant, and in the case of a utility that owns and operates nuclear units, it can be dire.

In its presentation at the stakeholder meeting OPG indicated its support for separate IRM models for its regulated hydroelectric generation assets and its nuclear assets. OPG stated that separate IRM models can be workable given the "separate operational businesses and different operating environments". Should the Board pursue IR for OPG, the PWU supports the separate approach and as a matter of fact, in the PWU's view, the use of a single IRM model is not plausible because of the differences in operating environments for which a common set of incentives could result in inconsistent outcomes.

4 OPG's UNCERTAINTIES

In assessing IR for OPG, in addition to IRM design challenges, the Board needs to consider the significant uncertainties that OPG faces that must be addressed in the IR framework. The uncertainty stems from the economy, OPG's planned massive capital programs, changes contemplated to Ontario's Independent Electricity System

[10] Joskow, Paul L. MIT. Incentive Regulation In Theory and Practice: Electricity Distribution and Transmission Networks. Center for Energy and Environmental Policy Research. 05-014. September 2005. Page 80.

Operator's ("IESO") administered market, and the operations of the distribution companies. Consequently, OPG is not in a "steady state" or "business as usual" mode and it is unrealistic to expect that reasonable base payments can be established for an IR term or that reasonable IR parameters can be developed.

Further, the Board needs to be mindful of the fact that there are significant issues that OPG needs to deal with that are not in its control. In an article on *How Performance Measures Can Improve Regulation,*[11] Costello identified the need to separate the effects of factors that are beyond a utility's control in applying performance measures and warns against mechanically applying performance measures:

> **Performance depends upon different factors, …, some under a utility's control, others exogenous to a utility. The challenge for regulators is to separate the effects of management from the effects of factors beyond a utility's control. Without separation, the proper applications of performance measures become greatly restricted. Specifically, it is unreasonable for regulators to then apply performance measures mechanically or as the sole source of information for evaluating a utility's performance.**

According to PA no nuclear-only IR has ever been implemented in North America. No doubt, there are intrinsic reasons why the twenty-year plus history of incentive regulation has unfolded without a single implementation of standalone-nuclear IR. This absence should cause the Board to pause and contemplate its future actions. The Board needs to thoroughly consider all the implications of the "IR bargain".

In fact, at the stakeholder meeting, some stakeholders raised concerns about unintended consequences and the inherent dangers of applying IR to nuclear generation. Energy Probe noted the scheme could create "perverse incentives" and that safety would be a trade-off. Energy Probe also noted that top down incentives are at odds with a safety culture and clearly articulated the need to embed safety standards. As Energy Probe succinctly concluded, some things were worth paying for.

[11] Costello, Ken. How Performance Measures Can Improve Regulation. National Regulatory Research Institute. June 2010. Page 10.

PA stated that the issues raised by Energy Probe were “difficult” and that PA could not provide any “comfort”. Indeed, PA stated that it had “skated over” these issues.

In this section the PWU describes the significant uncertainties that OPG faces that are major obstacles to the implementation of IR. The PWU then discusses how the typical IR TFP cap mechanism is inherently at odds with the operations of a generation facility and the uncertainties that it is subject to that are not in its control. The price cap is designed to allow output to vary within a price ceiling. However, this shifts an unacceptable level of risk onto a generator by allowing production and revenue to fluctuate with a wide array of uncontrollable events such as weather, recession, or structural changes in end-user or energy markets. The PWU then comments on an IR approach forwarded by London Economics that is intended to address the uncertainties that OPG faces.

4.1 Major Capital Projects

OPG faces significant challenges related to Ontario’s 2010 Long Term Energy Plan[12] (“LTEP”) that contributes to uncertainty. The LTEP includes major OPG capital projects i.e. the life extension of Pickering B, refurbishment of Darlington units, and new nuclear build at Darlington. The current economic instability can create significant uncertainty in the cost of materials and financing for these major capital projects. London Economics described these major capital projects as contributing to an environment that is not a steady state environment. London Economics noted that OPG’s long run historical dynamics are therefore not appropriate to apply on a forward looking rate setting mechanism basis.

With regard to its nuclear business OPG has anticipated:

- Pickering A and B nuclear stations will be out of service in early 2020;

[12] Ontario’s Long-Term Energy Plan – Building Our Clean Energy Future. Ministry of Energy. 2010. http://www.mei.gov.on.ca/en/pdf/MEI_LTEP_en.pdf

- The life extension of Pickering B units by four or more years (from 2014/2016 to 2018/2020); and,
- The Darling Refurbishment project is expect to start the first refurbishment outage in 2016. The completion of the project is expected for 2024.

It is clear that OPG will not operate in a steady state over the next 12 years. Under these circumstances OPG will have to accommodate capital expenditures well above what it will need consistent with steady state operations (i.e. the capital expenditures consistent with the depreciation expense on existing assets). Also, capital projects anticipated by OPG over the next years will significantly impact OPG's nuclear output.

4.2 IESO-Administered Electricity Market Impact

The LTEP provides for increasing amounts of variable renewable generation (i.e. wind and solar) that creates market uncertainty for OPG. The IESO-administered market is undergoing changes as a result of changes in Ontario's generation mix as set out in the LTEP and the 2011 Supply Mix Directive[13] to the Ontario Power Authority. The increasing amounts of variable wind and solar generation in the supply mix will have deleterious impacts on OPG's market participation as well as on its baseload generation assets.

Electricity generation, unlike electricity distribution and transmission, is not a natural monopoly and the economic regulation of OPG, an IESO-administered market participant, is an anomaly. Fundamentally, IR is intended to provide natural monopolies with incentive for efficiency improvement that in competitive environments is a result of market forces. OPG however, operates within a competitive market.

[13] Supply Mix Directive. Ministry of Energy. February 17, 2011.
http://www.powerauthority.on.ca/sites/default/files/new_files/IPSP%20directive%2020110217.pdf

Like any market, the IESO-administered electricity market is vulnerable to market uncertainties. In the Board's report on a regulatory methodology for OPG (EB-2006-0064), the Board noted that the regulated price arrangement is an "example of limiting OPG's total revenues while the energy produced from the prescribed generation assets is offered into the market". While the Board approves per unit (i.e. kWh) payment amounts for OPG's production from its regulated assets, the amount of energy offered into the market and dispatched depends on the IESO-administered electricity market conditions. The IESO market therefore impacts OPG's financial performance and operations. How IR might accommodate electricity market uncertainty is an obstacle that needs to be overcome in implementing IR for OPG, especially with the changing market related to the increasing variable generation (i.e. wind and solar) levels in the supply mix that is a result of the Ontario Government's energy policy. Changes contemplated to the IESO market rules to accommodate the increasing amounts of variable generation exacerbate the market uncertainty for OPG.

Surplus baseload generation ("SBG") is a growing issue for the IESO-administered market. In a presentation made at an IESO consultation on Renewable Integration (SE-91) the IESO identified the following impacts of the growing variable generation including the potential for increased SBG:

- **Lack of visibility of some variable resources**
- **Increased variability of demand and supply forecasts**
- **Limited flexibility of resources**
- **Potential for additional or extended periods of Surplus Baseload Generation**[14]

In describing the impact of SBG on hydroelectric facilities the PA Report notes that there are operational limits and consequences associated with the use of hydroelectric facilities to respond to SBG. The operational limits and consequences are a result of generating units that must "operate 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." In addition there

[14] IESO Centralized Forecast – Webinar. http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20111021-Centralized_Forecasting.pdf. Slide 10.

are public safety concerns related to potential downstream impacts of water spills. PA notes that the Board has directed OPG to address the Hydroelectric Incentive Mechanism ("HIM") in its next payment filing including, "an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches." These SBG considerations would need to be accommodated in an IR framework.

The PWU notes that recently OPG Nuclear was also required to react to an SBG event.

The IESO is currently developing a floor price approach to managing SBG. This development can have a major impact on generators' bid-strategies. The impact of the floor prices on OPG's regulated generation needs to be considered in any IR that the Board might contemplate. This impending market change contributes to uncertainty for OPG. The cost impacts of significant market developments would be considered in the COS review. Under IR, not only are costs delinked from the payment amounts, the effect of the market change on the Board's IR incentives may not be intuitively obvious.

4.3 Workforce Renewal

According to the 2012 report of the Electricity Sector Council electricity industry employers will need to recruit over 45,000 new workers between 2011 and 2016 which represents over 40% of the current workforce.[15] The new workers are required to replace retiring workers and to build and operate the next generation of infrastructure, including renewable energy, refurbished generation, and transmission and distribution systems.

It takes years to develop a recent hire to the "journeyperson" level of knowledge and output and significantly longer to develop a competent supervisor. Increased investment will be needed to recruit, mentor, train and qualify new employees to

[15] Electricity Sector Council. 2012. Power in Motion. 2011 Labour Market Information (LMI) Study Full Report. Page 4.

perform needed functions safely and efficiently as well as to train the next generation of supervisors. Vast improvement in enterprise-wide systems and processes are required to help trainees get up to speed including appropriate documentation, standardization of processes, and quality and certainty of data. These improvements are essential for the transfer of institutional knowledge to new employees and must be implemented before employees with the institutional knowledge and memory retire.

This workforce renewal has significant impact on OPG's costs as it does on the costs of other industry employers, and is an issue that needs to be accommodated in an IR approach for OPG.

4.4 The Price Cap Bargain: Fixed Prices and Variable Output

Under price cap mechanisms, regulated firms make a two-part agreement. First, the rate ceiling is fixed and subsequently adjusted through the IRM i.e. the rate adjustment mechanism. Given the specific values of the IRM's parameters, the adjustment historically has often been to lower the ceiling at the start of each year in the plan term. Second, and of critical importance for OPG, the output of the regulated firm under price caps is variable, i.e. the firm's production will be impacted by a wide variety of factors and events beyond its control. As its revenue is impacted, OPG's budgets could come under increased pressure and safety expenditures and activities could be cut.

Some of these factors are related to weather (e.g., very cool summers, hurricanes, blizzards, tornados), some to the economy (e.g. recessions and structural adjustments), and some to the network or electricity policies (e.g. outages, reliability degradation, line loss improvement, conservation, price adjustments).

In this section some of the risks and the quantification of the magnitude of the risks are discussed.

A number of event-related output losses have been observed over the past twenty years in Ontario. Some of these output losses have been substantial. Such events that potentially affect OPG's production include:

- Price increases;
- Economic cycles;
- Structural changes and customer plant closings;
- Non-seasonal temperatures;
- Load loss related to extreme weather events;
- Reliability related outages,
- Distributors potential improved line loss performance

All of these factors have cut OPG's output in the past and almost certainly will impact OPG's output in the future.

Over a longer term, changes to other structural conditions can also significantly reduce OPG's output:

- Conservation programs and home energy improvements;
- Take-or-pay contracts with independent power producers; and,
- Wind and other renewable supplies bumping OPG production.

Some of these events are major discontinuities occurring in the electricity market itself.

OPG's output will certainly be affected by a number of the events listed above. It is likely that the losses associated with individual factors could put notable revenue pressure on OPG. When impacts are considered in combination, OPG's actual lost revenue may be markedly larger than the revenue reduction brought about by whatever X factor might be imposed by the OEB in an IRM. The combination of the Board's mandated X factor and the occurrence of one or more of the events listed above would reduce OPG's revenue by a significant amount. The demand elasticity response to the forecast rise in power prices alone will cause power output to decline.

It is unlikely that regulators would want nuclear power generators to be faced with choosing between profit or safety when an event impacts generation demand and revenue. Therefore, the lack of precedence of IR for nuclear generation should not be surprising. The consequent absence of any nuclear-only implementation should cause the Board to reconsider its intended implementation of IR for OPG.

4.4.1 Price Elasticity Responsiveness

Customer response to price changes usually occurs over a period of time following the change in price. In the short run, customers have fewer options and responses may be somewhat muted. Over the longer term, customers can explore more options and examine choices which produce more optimal outcomes. The latter usually entail larger adjustments than seen near term as customers optimize over a longer time horizon.

For example, if we look at the research on residential electricity demand we see that the long run response is potentially two to three times, or more, what the short run response might be. Alberini and Filippini (2010)[16] provide a review of prior literature and their own estimates of the price elasticity of demand for residential electricity. They find that in the short run, if the price of electricity were to double, residential demand would fall 20 to 35 percent; a fifty percent increase in price would reduce demand 10 to 18 percent. In the long run, they conclude that residential demand would fall 30 to 80 percent; a fifty percent increase in price would reduce demand 15 to 40 percent.

According to the US Department of Energy ("DOE"), for the commercial sector, the short-run price elasticity estimate for all major end uses except refrigeration is similar to Alberini and Filippini's residential estimate and would produce similar reductions in demand to price increases.

[16] Alberini, A. and Filippini, M. Response of Residential Electricity Demand to Price: The Effect of Measurement Error. Centre for Energy Policy and Economics. CEPE Working Paper No 75. July 2010.

For the industrial sector larger responses are expected since many end-users have already implemented energy strategies in the past during other periods of price increases. For example Agnolucci (2009) found similar price elasticity for both the short and long run for industrial electricity demand: a short-run response of 32 percent to a fifty percent price increase.[17]

Agnolucci, notes that this high price elasticity provides an effective policy tool for reducing demand. So too would higher prices in the case of Ontario.

Between 2010 and 2015, the price of electricity is forecast to rise almost 50 percent in Ontario. Based on the extensive econometric research on the price elasticity of demand, some of which is reviewed above, reduction in demands across all end-use sectors can be expected with very significant reductions passed back to OPG.

4.4.2 Economic Cycles and Structural Changes

Economic cycles and structural adjustments can have significant impacts on power demands. Both residential as well as commercial-industrial loads can be lost with the economic declines associated with recessions and structural changes.

Economic Cycles

In Table 1 below, residential load impacts are examined using data for the 1990s that was filed with the Board by 13 Ontario distributors in 200018 as well as in rate submissions and other published data sources. Column 2 indicates that between the years 1993 and 1999, there was a notable change between the peak year of residential consumption and the trough. The range covers a decline of 7.7 to 34.2 percent. The decline exceeded 10 percent for seven of the 13 distributors.

[17] Agnolucci, Paolo. The Energy Demand in the British and German Industrial Sectors: Heterogeneity and Common Factors, *Energy Economics*, January, 2009: 175-87.

[18] OEB. RP-2000-0069. Submission of Hamilton Hydro in the Generic Proceeding on June 7, 2000 Minister's Directive.

Table 1. Residential Load Losses for a Sample of Ontario MEUs

Utility	1993-1999 Peak to Trough Percentage Change Residential Kwh	Residential Share of Total Revenue
1	-24.7	48.9
2	-34.2	52.0
3	-08.5	58.6
4	-19.8	51.5
5	-11.01	47.0
6	-19.1	35.1
7	-33.9	31.8
8	-14.8	48.0
9	-8.8	58.9
10	-8.7	55.8
11	-5.9	53.0
12	-7.7	56.2
13	-5.1	72.3

While reasons for such a decline vary, they can be expected to include: economic trends related to growth and alternative fuel choices; cyclical economic impacts and short-run energy prices; conservation; and, weather. An econometric model could be estimated to examine more precisely the individual causal factors and separate out their net effects as is done for load forecasts. A similar model could be estimated to examine the full array of causal factors impinging on the demand for electricity by major end-users. In such an analysis, the effects of a recessionary cycle could be viewed separately from the effects of unusual temperatures, severe weather, blackouts, price increases, conservation or long-term economic growth. The PWU strongly recommends that such an analysis be done before any IR is imposed on OPG.

Residential loads were also impacted by the events that transpired over the latter part of the decade. Table 2 presents data for a very small sample of Ontario distributors that indicates residential load loss exceeded 15 percent for some distributors (e.g. Horizon and Kitchener).

For non-residential losses the upper bound exceeded 21 percent (e.g., Horizon and Kitchener).

Table 2. 2005-2010 Peak Residential and Non Residential Load Losses for a Sample of Ontario Distributors

	Peak Loss Period	**Residential Loss**	**Non-Residential Loss**
Horizon	2007-2009	-15.6 %	-20.4 %
Kitchener	2005-2009	-15.2	-21.3
Burlington	2005-2009	-8.8	-15.1
Enersource	2005-2009	-6.4	-10.1
Toronto	2005-2009	-6.0	-5.3
Hydro One	2005-2010	-4.2	-5.8

Structural Changes

The economy is constantly adjusting to cyclical and structural adjustments. While structural modifications reflect the consequences associated with long-term changes, the associated events often occur precipitously, reflecting the accumulation of many impinging factors. For example, in the last 3-5 year period, important Ontario industries have suffered significant declines in production, including the following industries:

- Smelters[19] and high energy prices in Ontario[20] (Timmins' Xstrata plant);
- Steel fabricators[21] (US Steel's plant in Hamilton, formerly Stelco and the Timken plant[22]); and,
- Pulp and paper mills[23] and load curtailments.[24]

No doubt, similar structural changes can occur over the course of an IR term that bring with them notable losses of load which may be embedded in the IR's baseline revenue and difficult to replace.

4.4.3 Non-Seasonal Temperatures Reducing Load

Over the past 30 years, there have been occasions when non-seasonal temperatures have notably reduced load. A causal look over historical temperature data reveals a number of such instances. Such events occurred in the summer of 1982, 1985, 1986, 1992, 1996, 1997, 2000, 2004, and 2009, among others.[25] In some cases, the event triggered notable reductions in kWh consumption.

For example, in 1992 the observed mean summer temperature was markedly below the long-term trend. In Hamilton the summer average was about 17 degrees versus the long-term average of just under 20 degrees, or about 14.1 per cent below the trend. Despite a 1.2 per cent increase in the number of residential customers, Horizon's residential demand declined 7.4 per cent from its 1991 level. In London, despite a 1.4 per cent increase in the number of residential customers, residential kWh consumption declined 6.7 per cent year-over-year.

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[19] http://www.timminspress.com/2011/01/02/smelter-closure-has-left-resounding-impact
[20] http://www.northernontariobusiness.com/Regional-News/timmins/Top-Five-Newsmakers-of-2010--Timmins-brainstorms-following-closure-of-Kidd-Met-Site.aspx
[21] http://www.cbc.ca/news/business/story/2010/10/01/us-steel-hamilton-closure.html
In 2008 the plant employed about 2400 employees.
[22] http://www.amm.com/Article/3035767/Steel/Timken-to-close-Ontario-steel-bearings-plant.html
[23] http://www.pulpapernews.com/2012/04/cascades-to-close-its-norampac-mill-in-ontario
[24] http://foresttalk.com/index.php/category/mill-closures-layoffs/
[25] http://www.climateontario.ca/doc/publications/datasheet_Hamilton.pdf

In a more recent year, 2009, the mean summer temperature in Hamilton was approximately 18 degrees: about 10 per cent below the long-term trend. Despite a 0.4 per cent increase in the number of residential customers, Horizon's residential demand declined 2.7 per cent from 2008. In London, despite a 1.2 per cent increase in the number of residential customers, residential consumption fell 4.6 per cent year-over-year.[26]

4.4.4 Load Losses from Growing Incidence and Severity of Extreme Weather

Severe weather appears to be happening more frequently and some would argue are more extreme. Two examples that produced record setting impacts and occurred about two months apart are Hurricane Irene in late August 2011 and the Halloween Nor'easter in October 2011. Both resulted in massive electricity service outages.

4.4.5 Blackouts and Outages

Blackouts and managed outages/curtailments are a fact of life for the electricity industry. Over the past decade multiple outages have been reported in Canada and the US. In the US there were the following events: the Southwest blackout of 2011 (7 million customers affected); the Texas outages of 2006 and 2011; the New York blackout of 2007 (and of course the famous 1977 blackout); and, the outages and cutbacks in California over the 2003-2005 period. Alberta imposed power cutbacks in 2012. Major outages have also been recorded in New Zealand, Italy, and Brazil among other jurisdictions.[27]

Indigenous outages are not the only risk. There have been major instances where out-of-jurisdiction electricity failures have cascaded over state and national borders. It is quite possible that an outage occurring outside Ontario could result in a notable loss of load for OPG. Such outages, beyond the jurisdiction, oversight, and control of the Ontario government, regulators, and electricity industry could cause notable

[26] Economic cycle impacts may be co-mingled with these data.
[27] http://en.wikipedia.org/wiki/List_of_power_outages

losses for OPG. The 2003 blackout took the grid off-line for between 12 and 16 hours.[28]

4.4.6 Reliability Degradation

The PWU notes that there have been on-going discussions among stakeholders regarding the need for enhanced investments in infrastructure on the part of the distributors. Distributors have maintained since at least 2006 that the levels of investments by the distributors were insufficient to ensure the reliable delivery of power in Ontario and that the network requires sizable new capital additions to compensate for prior underinvestment and provide a network robust enough for future electricity needs (see section 5.1). Were reliability to degrade, OPG would suffer significant loss of load.

However, as a result of the perverse incentives embedded in the IR for the Ontario distributors, we now know that unanticipated changes have occurred over the past five years or so in distributor investments.[29] A massive shift occurred in labour capitalization among Ontario distributors. The average increase was 228 percent. That is, over the past decade labour capitalization rates more than tripled. Since each dollar of capital additions is now comprised of less hardware, higher amounts of capital additions will be required than would have been previously to remedy degradation of the network's reliability.

4.4.7 Distributors Potential Improved Line Loss Performance

The PWU's submission on the OEB's Renewed Regulatory Framework for Electricity transmitters and distributors includes analysis that indicates that between 1995-1997 and 2009 line losses have degraded by 33 per cent on a customer-weighted basis and 20 per cent on a simple average basis. Since deregulation in the early 2000's line losses in Ontario have been incorporated in the electricity charge removing the

[28] We might also note that the cause of the 2003 outage has been linked to First Energy efforts in cost cutting O&M and the impact this had on their transmission system.

[29] For further information, see, F. J. Cronin. Assessing Distributor Incentives and Performance: 2000 to 2012. The Power Worker's Union submission to the OEB for the Renewed Regulatory Framework. April, 20, 2012.

incentive for the distributors to minimize line losses. The degradation reversed a sizable improvement made during the late 1980s and early 1990s.

In Alberta line loss reduction incentives were introduced under its Formula Based Ratemaking plan that have resulted in reduced line loss rate for Enmax Power Corporation from 3.02 to 2.83 per cent in 2010.[30] Should the OEB introduce incentives for the distributors that reverse the line loss degradation the impact on OPG will be significant. In the near term, this decline in demand would translate into lower output and lower revenue to OPG. The decline in revenue would be hundreds of millions of dollars over a three to five year period. From society's viewpoint, in the longer term, especially once OPG and the network adjusted to the rationalized downsizing, the return would be notable. However, the rationalization should not place cost pressure on OPG's O&M and safety activities as it might under IR.

4.4.8 Conservation Programs and Home Energy Improvements

Conservation efforts and home energy improvements continue to make progress. These advancements will have an impact on OPG residential loads. New houses now offer dramatic energy savings over existing structures. For example the 2009 International Energy Conservation Code ("IECC") offers 12 – 15 percent savings over the 2006 IECC. Some builders now have home building standard that provide 35 percent savings over the 2009 IECC. As more new houses are rolled into the inventory, the average residential load will decrease.

4.5 The Building Block Approach

As noted in section 3 there is the need for a steady state environment for a workable TFP IRM. In the absence of a steady state for OPG, London Economics proposes the Building Block approach that would make "very clear considerations" on

[30] There is a cost that comes with line loss improvements: however, such costs are those that are a result of good investment planning practice that ensure system sustainability and ongoing service quality that stakeholders expect and value.

operating and capital costs and future output. In the Building Block approach forwarded by London Economics:

> **…productivity targets are embedded in the *forecast of future operating and capital costs that are then used to forecast a revenue requirement and rate schedule*. The X factor is not the productivity factor itself but rather a growth factor for rates that indirectly represents productivity improvements over time and the smoothed net present value of the revenue requirement per unit of output.**[31]

While London Economics suggests using a Building Block approach to address non-steady state circumstances, as London Economics observed, the development of the details of the Building Block approach have yet to be considered. In the PWU's view the development of the details of the Building Blocks to properly address the non-steady state circumstances will likely involve significant risk for OPG. Therefore, while conceptually, the Building Block approach appears to be a suitable approach to address the uncertainties faced by OPG, the PWU would want to understand the details of how the issues described in this section would be addressed before commenting on the approach. As discussed in this section, the scope of the uncertainties that will need to be addressed through the Building Block approach would be substantial and complex.

5 IR EXPERIENCE

In this section, U.S. experience with IR for nuclear generation, the Board's IR experience, and Ofgem's IR experience are reviewed. The lessons learned suggest that there is much that would need to be addressed in implementing IR for OPG. The Board's current approaches to IR cannot be relied on in the development of a robust IR framework for OPG to ensure ongoing cost and quality performance.

As noted earlier, the Board has indicated that it is not aware of IR plans applicable to generation-only utilities that might help in the development of a plan for OPG. As

[31] London Economics International LLC. Considering Incentive Rate Making Options for OPG's Prescribed Generation Assets. Presentation at the Stakeholder Meeting hosted by the Ontario Energy Board. August 28, 2012. Page 5.

well, the Board correctly noted that it is not a simple matter of transferring a plan from natural gas and electricity distribution to OPG.

The lack of IR plans for generation-only utilities are likely the result of the economic deregulation and restructuring in the electricity industry in the 1990's intended to increase competition in the industry.[32] Therefore, case studies on IR for nuclear generation stations are likely to date back to pre-restructuring and in most cases are likely to encompass integrated utilities (i.e. delivery plus generation). As noted in section 4 the OEB's regulatory authority over OPG's regulated assets imposed subsequent to the deregulation and restructuring of Ontario's electricity sector is an anomaly.

There is no evidence that capital projects of the scope and complexity of the nuclear projects that OPG will be undertaking (i.e. Pickering B continued operation, Darlington refurbishments, and Darlington new build) have ever been accommodated in an IR approach. Furthermore, as described in this section, there have been concerns expressed on the possible impact of IR on the performance of utilities with nuclear generation that need to be taken into account in considering IR for OPG. These challenges limit the confidence that there is a solid base of IR experience that the Board can rely on to develop a robust IR framework for OPG in the short term, if ever.

5.1 IR for U.S. Nuclear Generation

PA indicates that there is limited experience in designing broad-based IRM approaches for electricity generators either for an independent generation entity or for the generation business unit of a vertically integrated utility. According to PA, 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

[32] Nuclear Regulatory Commission. 10 CFR Part 50. Final Policy Statement on the Restructuring and Economic Deregulation of the Electricity Utility Industry. 7590-01-P. Page 11, Paragraph 2. http://www.nrc.gov/reading-rm/doc-collections/commission/secys/1997/secy1997-117/attachment.pdf

hydroelectric facilities. However, PA notes that 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.[33]

A study prepared by R.L Martin, K. Baker and J. Olson for the NRC indicated that prior to deregulation in the 1990s, several U.S. states introduced incentive programs for efficiency in the operation of nuclear units designed to provide incentives for utilities to increase output and cut costs.[34] These programs used predetermined formulas based on the performance of the nuclear power plant to determine the size of the financial reward or penalty applied to a generating unit or to all system generating assets. Nuclear performance varied widely within the criteria used to measure performance. The criteria included heat rate, capacity factor, or availability factor.

At the time, the NRC was concerned that as nuclear power owners pursued cost-cutting strategies to face future competition, safety priorities might be jeopardized. The NRC closely monitored the implementation of IR programs and performance criteria to nuclear generation, and urged licensees and State regulatory commissions to inform the NRC of incentive programs.

The NRC identified programs as belonging to one of the following three classes: (1) nuclear performance incentive programs; (2) utility performance standard programs; and, (3) utility economic incentive programs. A program classified as a nuclear performance incentive program had the following two characteristics: it included nuclear performance standards; and, it must link to specified predetermined revenue adjustments. Utility performance standard programs made use of either a nuclear or a utility performance standard to determine the prudency or reasonableness of operations. Utility performance standard programs were not directly linked to predetermined rewards or penalties but were used in determining allowed recovery

[33] PA Report, Page 40.
[34] Nuclear Regulatory Commission. NUREG/CR-4911. Incentive Regulation of Nuclear Power Plants by State Regulators. February 1991.

of fuel costs. Utility economic incentive programs provided specified revenue adjustments that were not directly linked to generating asset performance, but were based on a utility efficiency parameter, such as total fuel costs.[35]

In 1991, the NRC issued a policy statement in which it raised concern that certain forms of performance incentive programs might adversely affect the operation of nuclear plants and the public health and safety. The NRC's concern was on the following features of nuclear incentive programs used by some states:[36]

a) Sharp thresholds between rewards and penalties - The NRC defines a sharp threshold as a situation in which a licensee narrowly misses a target capacity factor and must bear a large part or all of the resulting replacement power costs. The NRC determined that an incentive program with a sharp threshold could prompt a licensee to continue to operate a plant to achieve a target capacity factor in order to avoid the large replacement power cost or to earn a substantial reward. The NRC's concern was that this type of incentive could divert attention from safe plant operation. To minimize this affect, the NRC indicated that State regulators should consider a reasonably broad dead band around the targets in which no rewards or penalties are imposed.

b) Performance measurements that have short time intervals - Performance measurements for short-term intervals would encourage licensees to focus on short-term targets such as a higher capacity factor or availability factor. According to the NRC, this target could become the primary focus, diverting attention from the long-term goal of reliability and operational safety. In contrast, NRC favoured performance measurements for long-intervals that would prompt nuclear operators to follow sound operational and maintenance practices to improve performance.

[35] Ibid.
[36] Nuclear Regulatory Commission. 56 FR 33945. Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement. July 1991.

The NRC asserted that performance measurements featuring sharp thresholds and short-term intervals should not allow licensees to operate a plant when it should be shut down for safety reasons.

The NRC stated its intent to request nuclear operators to report to the NRC when state regulators develop or substantially revise economic performance incentives. Further, the NRC stated its intent to ask for discussions with the Federal Energy Regulatory Commission ("FERC") and state regulators on the incentive programs so that the NRC could assess how the programs would affect nuclear plant safety:

> **….the NRC will request by generic letter that licensees report whenever these commissions develop or substantially revise EPIs [economic performance incentives]. The NRC also will ask FERC and the State utility regulatory commissions to discuss with the NRC initiatives to impose or change an EPI program that applies to an NRC licensee. The NRC will take these actions in order to gain information on the principal features of the program so that the NRC can assess the extent to which the program will affect plant safety. Further, by a generic letter, the NRC will request licensees to report the rewards and penalties assessed through these programs as they occur. A free exchange of information between the NRC and the agencies with economic jurisdiction over nuclear utilities will help the NRC and those agencies to work together to achieve the goals of the safe and economic operation of nuclear power plants.[37]**

In a 1999 study, K. Verma, B.M. Mitnick and A.A. Marcus[38] assessed the regulatory incentive programs that were intended to improve efficiency in nuclear plants using a 1987-1990 data set (e.g. prior to deregulation and restructuring) obtained from the US DOE and NRC sources. The study found that the programs did not enhance efficiency and may challenge nuclear plant safety. The authors suggest that one of the reasons may be that the link between reward and performance may not have been strong enough and the rewards not large enough. This finding is consistent with the conclusions presented by Harbourfront at the stakeholder meeting. Harbourfront concluded that based on its U.S. nuclear performance modeling and

[37] Ibid.
[38] Verma, K., Mitnick, B.M. and Marcus, A.A. Making Incentive Systems Work: Incentive Regulation in the Nuclear Power Industry. Journal of Public Administration Research and Theory: J-PART, Vol. 9, No. 3 July, 1999. pp. 395-436.

regulatory experience, incentives (penalties) tied to performance standards would not change nuclear performance.[39]

Further the 1999 study suggested that the existence of an important social priority, safety, may have been blunting the effectiveness of the incentives:

> **This study's results regarding the effects of incentive programs on the efficiency of nuclear plants do not support the argument that they improve efficiency. The results do not suggest that the receipt of rewards or penalties is associated with subsequent improvement in performance; the link between reward and performance does not appear to be strong enough. The rewards themselves may not be large enough. Finally, the existence of another important social priority, safety, may be blunting the incentives' effects. While evidence supports the argument that more-focused programs using a single performance measure are successful, many existing programs employ more than one performance criterion. The industry, however, has been spending more on production, which over time seems to improve performance anyway. Unfortunately, the presence of more-focused incentive programs seems to yield more reactor shutdowns. Ironically, incentive systems that may be more likely to enhance efficiency (i.e., focused incentive programs) may adversely affect safety.[40]**

The study revealed that incentive programs that pursue an increase in performance efficiency (i.e. as measured by capacity factor) may conflict with safety.

> **…the results for safety performance do not provide strong support for the hypothesis that the presence of incentive programs could be detrimental to all kinds of safety performance. The presence of more-focused incentive programs, however, seems to result in a higher number of reactor shutdowns, which could indicate an overextension of the unit. Ironically, incentive systems that may be more likely to enhance efficiency (i.e., focused incentive designs) may in at least some contexts adversely affect safety. In addition, the presence of incentive programs has been found to be associated with safety system actuations.[41]**

The study's concluding remark speaks to the need to consider the full range of factors that impact the success of incentive programs and warns against efficiency and performance expectations based on simplified incentives:

> **Perhaps the most important suggestion we can offer as a consequence of the analysis in this article is that incentive programs must be designed with**

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[39] Harbourfront Group Inc. Analytical and Regulatory Issues Surrounding U.S. Nuclear Performance Standards (NPS). Presentation at the Stakeholder Meeting hosted by the Ontario Energy Board. August 28, 2012. Page 9.

[40] Verma, K., Mitnick, B.M. and Marcus, A.A. Making Incentive Systems Work: Incentive Regulation in the Nuclear Power Industry. Journal of Public Administration Research and Theory: J-PART, Vol. 9, No. 3 July, 1999. Page 425.

[41] Ibid. Page 424.

systematic and integrated attention to the full range of factors that may be associated with producing success via such systems. The firm is not like a big iron pump with a single-handed lever on top; you can't pump a simple reward in and expect that the waters of efficiency and safety will flow, mingled together.[42]

This advice, based on IR experience for nuclear generation is pertinent to IR for OPG and is an essential consideration in the Board's deliberations on this matter.

There are documented cases of management's pursuit of cost cuts resulting in the deterioration of nuclear plant condition. One such case is the Millstone Nuclear Power Station ("Millstone") in Connecticut. According to a 1996 comprehensive review by an independent auditor, management's decisions in the late 1980s were the cause of Millstone's deteriorating plant conditions.[43] According to the auditor's review, concern about the need to trim costs in the face of the upcoming competitive environment led Millstone to manage close to the regulatory safety margin. This decision translated into deferred maintenance and increasing corrective action backlogs that eventually led to a shutdown and several hundred million dollars' worth of repairs.

In March 2002, the most serious safety issue confronting the U.S. nuclear generation industry since Three Mile Island was identified at the Davis-Besse plant in Ohio. After the NRC allowed Davis-Besse to delay a shutdown to inspect its reactor vessel for cracked tubes, the plant found that leakage from these tubes had caused extensive corrosion on the vessel head, a vital barrier to the release of radioactive material.[44] In identifying the actions and lessons learned related to this event the U.S. DOE noted that Davis-Besse's corporate incentive programs were aligned toward short-term production. In combination with other incentives, such as rewards for meeting or exceeding outage goals, emerging work and repairs that did not affect generation were often deferred. The DOE found that this was particularly true for tasks

[42] Ibid. Pages 428-429.
[43] United States General Accounting Office. Report to Congressional Requesters. NUCLEAR REGULATION. Preventing Problem Plants Requires More Effective NRC Action. GAO/RCED-97-145. May 1997. Page 5.
[44] United States General Accounting Office. Report to Congressional Requesters. NUCLEAR REGULATION. NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown. GAO-04-415. May 2004.

associated with reactor pressure vessel head cleaning. One of the lessons learned set out in the DOE's action plan was that budget and schedule pressures must not override safety considerations.[45]

The Millstone and Davis-Besse cases illustrate the impact of management decisions on cost cutting measures. While OPG does not operate in the competitive environment that would induce it to cut costs and manage close to the regulatory safety margin, the Millstone and Davis-Besse cases draw a parallel for IR approaches that provide similar cost and time pressures that can result in irrational cost cuts.

The Millstone and Davis-Besse cases also illustrate the link between economic incentives for cost efficiencies at nuclear plants and the vigilance required by the nuclear safety regulator. Given this link, should the Board embark on IR for OPG, it would be wise for the Board and OPG to communicate with the CNSC on the IR approach being considered, much in the manner articulated by the NRC in its policy statement.

Of interest is the reference in Martin *et al*'s[46] article to utilities' concern with financial rating agencies reacting negatively to the imposition of incentive programs for nuclear plants:

> **Incentive programs may minimally affect the budgets of utilities as the programs are intended to function as an alternative to routine individual outage reviews and fuel cost disallowances. However, the visibility of the penalties and the resulting decrease in revenues are frequently viewed by the utility as equally undesirable. Ratepayers and utility stockholders may view penalties as an indication of deficient management. The imposition of nuclear performance standards on utilities has, in a number of cases, impacted investment in utilities' generating assets; a number of financial rating agencies have reacted unfavorably to the imposition of incentive programs. Selected utilities have expressed general concern over the reactions of the financial community, pointing out that the major rating agencies have downgraded a few utility securities (Franklin and Hirvo, 1990).**

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[45] U.S. Department of Energy Action Plan. Lessons Learned from the Columbia Space Shuttle Accident and Davis-Besse Reactor Pressure-Vessel Head Corrosion Event. July 2005.

[46] Martin, R.L., Baker, K., and Olson, J. Incentive Regulation of Nuclear Power Plants by State Regulators. Pacific Northwest Laboratory. Battelle Human Affairs Research Center. NUREG/CR-4911. PNL-7596. February 1991. Page 1-3.

In fact, just recently in a May 2012 study on regulatory risk in the utilities sector, the credit rating agency DBRS indicated that it views COS as lower risk than IRM.[47]

5.2 OEB's IR Experience

In addition to the apparent lack of precedence on an IR framework for a generation-only utility there are paucities in the OEB's experience with IR to date that still need to be addressed.

5.2.1 Electricity Distributors

The OEB's evolution towards a comprehensive IR for the electricity distributors is still ongoing. The issues that still need to be addressed include the significant requirements for capital investments, availability of capital cost information, total cost benchmarking, and service quality performance targets and incentives.

The OEB implemented an IR approach for the Ontario electricity distributors starting with First Generation Performance Based Regulation ("PBR") in 2000.[48] The First Generation PBR framework was a total cost price cap mechanism consisting of an industry inflation index minus productivity adjustment. First Generation PBR[49] was characterized as a transition plan that was to have a mid-term review to help design a second generation PBR. While it included minimum service quality performance guidelines it did not include performance incentives (i.e. penalties/rewards). The Board's view was that appropriate assessments of remedial action and financial consequences around service quality degradation could not be made until the Board and industry gained experience with the PBR plan and service quality performance data becomes available:

> **The Board has also considered the suggestions by parties that the PBR plan include remedial action and financial consequences in the case of service quality degradation. In the Board's view an appropriate assessment of these matters cannot be made until the Board and the industry have gained**

[47] DBRS. Industry Study. Assessing Regulatory Risk in the Utilities Sector. May 2012. Page 4.
[48] OEB. RP-1999-0034. Decision with Reasons. January 18, 2000.
[49] Ibid.

experience with the application of the PBR plan for the first year and appropriate service quality performance data becomes available.[50]

The Board described 2nd Generation IRM for the electricity distributors as a "transitional mechanism and not an end-state in itself" that responded to the Board's need "to put in place a formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers":[51]

> **Like the selection of the inflation measure, the selection of the X-factor is, for 2nd Generation IRM, a function of simplicity and transparency. Since 2nd Generation IRM is of a short duration, the Board will not develop an X-factor calibration that attempts to explicitly consider the productivity capabilities of each individual electricity distributor along with a stretch factor. Differentiated X-factors based on individual distributor circumstances would require an examination of distributor-specific evidence. In light of the spectrum of X-factor values put forward by distributors (as low as 0.7%) and consumer groups (as high as 1.2%) below, the Board believes that the 1% X-factor is reasonable for 2nd Generation IRM.**[52]

In the consultation on 2nd Generation IRM the utilities raised the issue of aging infrastructure and the need for increased investment in order to maintain the appropriate levels of service, which may be beyond the level supported by existing rates. The utilities proposed that the IR formula allow for increment capital costs. Hydro One Network Inc.'s expert consultant proposed a "factor that would be an incremental percentage to the price cap index, contingent on a distributor filing an asset condition assessment in support of its proposal". In rejecting the proposal the Board indicated its concern that a capital expenditure factor would reduce the price cap mechanism incentive:

> **Typically, an incentive regulation mechanism is intended to encompass both capital and operating costs. This increases incentives for operating performance. In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and**

[50] Ibid. Page 53, Paragraph 5.1.27.
[51] OEB. EB-2006-0089. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. Page 23.
[52] Ibid. Pages 31-32.

monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[53]

The Board indicated that utilities' need for inordinate capital investments could be accommodated through the rebasing of rates for 2nd Generation IRM.

Once again, the Board did not include service quality performance incentives in 2nd Generation IRM. The Board noted that a consultation process that was to address regulatory consequences for persistent below-standard performance was not completed. The Board acknowledged stakeholder's concerns and committed to resume its service quality regulation ("SQR") review to refine its SQR for electricity distributors.[54]

Considerable more time and effort was put into the development of the OEB's 3rd Generation IRM for electricity distributors than 2nd Generation IRM. However, Board difficulty with the use of pre-2006 utility information limited the ability to set the productivity factor based on Ontario data. In addition, for the assignment of productivity stretch factors, Ontario distributors were assigned to peer groups based on O&M cost benchmarking rather than total cost benchmarking.[55]

Implementing a compromised IRM can provide unintended flawed incentives. In the case of 3rd Generation IRM the decision to use O&M benchmarking instead of total cost benchmarking has penalized distributors with higher total cost efficiency and has resulted in a massive shift of labour costs from OM&A to Capital. The unintended impact of the compromised IRM is faster growth in rate base, higher cost and intergenerational subsidy issues.[56]

In a Board consultation on rate-making associated with distributor consolidation, distributors raised the need for policy that allows opportunity for capital investment

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[53] Ibid. Page 37.
[54] Ibid. Pages 39-40.
[55] OEB. EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 21.
[56] OEB. EB-2010-0379. PWU submission on the Renewed Regulatory Framework for Electricity Transmitters and Distributors – Defining and Measuring Performance of Distributors and Transmitters. April 20, 2012. http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

needs to be addressed as and when they arise.[57] In response, the Board indicated that concerns related to rebasing to account for needed capital expenditures should be examined in the development of 3rd Generation IRM.

While the Board included a capital module in 3rd Generation IRM,[58] the application of the module has been restrictive. In rejecting Hydro One Network's application for a capital module (EB-2008-0187) the Board indicated that the module is intended to accommodate only extraordinary and unanticipated capital spending requirement:

> **In fact what the Board requires in considering an application under the incremental capital module is a demonstration that the distributor is facing extraordinary and unanticipated capital spending requirements; i.e. something other than the normal course of business.[59]**

Toronto Hydro ("THESL") articulated its challenges on sustainability within the Board's IRM for electricity distributors in a letter to the OEB:

> **... In circumstances where material factors other than inflation and productivity are absent, IRM presents advantages of simplicity and predictability. However, it is unreasonable to expect IRM to accommodate factors that it is not designed to account for, and it is prejudicial to effectively deny the existence of those factors (e.g., significant infrastructure and workforce renewal) by imposing IRM in circumstances where those factors do exist, and which, in THESL's case, are likely to persist for the foreseeable future.[60]**

Consideration of a utility's capital costs is a significant issue in IR. In his 2005 report on the theory and practice of IR for network companies, P.L. Joskow noted that the lack of consideration of capital cost accounting and investment issues in IR can lead to serious performance problems:

> **Capital cost accounting and investment issues have received embarrassingly little attention in both the theoretical literature and applied work on price caps and related incentive mechanisms, especially the work related to benchmarking applied to the construction of price cap mechanisms. Proceeding with price caps without this regulatory information infrastructure and an understanding of benchmarking and the treatment of capital costs, as**

[57] OEB. EB-2007-0028. Cover Letter. Report of the Board on Rate-making Associated with Distributor Consolidation. July 23, 2007. Page 5.
[58] OEB. EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008.
[59] OEB. EB-2008-0187. Decision. May 13, 2009.
[60] OEB. EB-2011-0144. THESL Notice of Filing Intentions for 2012 Distribution Rates. March 25, 2011. Page 3.

has been the case in many developing countries following guidance from World Bank regulatory gurus, can lead to serious performance problems.[61]

While the Board amended the Distribution System Code with the addition of mandatory customer service performance standards and indicated that it expects similar amendments related to service reliability performance standards, as with the first two generations, 3rd Generation IR still does not include incentives for service quality performance:

> **When the Board launched the Rate Plan, it also committed to implementing a regime of service quality requirements which would work to ensure that consumers continue to receive a high level of service from their distributors during the term of an IR plan.**
>
> **On June 4, 2008, the Board issued amendments to the Distribution System Code which established a set of customer related service quality requirements with associated performance standards. These requirements include four previous service quality indicators (Connection of New Services, Appointments Met, Telephone Accessibility, and Written Response to Enquiries) and three new requirements (Appointment Scheduling, Rescheduling a Missed Appointment and Telephone Call Abandon Rate).**
>
> **These service quality requirements and associated performance standards will come into effect in January 2009.**
>
> **For the time being, the three existing system reliability indicators (SAIDI, SAIFI & CAIDI) will continue as reporting requirements. However, the Board's expectation is that system reliability requirements will eventually become mandatory.**[62]

The need to integrate cost and service quality performance incentives in IR is elaborated on in section 7.

The PWU notes that on October 27, 2010 the OEB initiated a consultation on a Renewed Regulatory Framework for Electricity Transmitters and Distributors ("RRFE") in which it will review its approach to network investment planning by transmitters and distributors, its rate mitigation policy, and its current rate-making policies.[63] The Board's letter announcing that initiative stated that the output from the

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[61] Joskow, Paul L. Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks. Center for Energy and Environmental Policy Research. 05-014. September 2005. Page 82.

[62] OEB. EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 43.

[63] http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/letter_Renewed_Reg_Framework_Electricity_20101027.pdf

review “will be an important consideration in the Board’s work regarding revenue decoupling and incentive regulation”. There is the likelihood therefore that further evolution of the Board’s IR for distributors will result from the RRFE consultation.

5.2.2 Gas Distributors

The current IR plans for the Ontario gas distributors, Enbridge Gas Distribution Inc. (“EGD”) and Union Gas Ltd. (“Union”), are their first total cost IR plans and were arrived at through mediation in the Board’s settlement process.[64] While the two gas distributors have different IRMs, with EGD under a revenue cap and Union under a price cap, neither plan includes a factor for incremental capital investment costs. Nor do they include standards and incentives for service quality performance.

Of interest is a report prepared for Board staff by Pacific Economics Group Research (“PEG-R”) on the Impact of the existing IR plans on EGD and Union.[65] According to PEG-R the IR plans satisfied the Board’s criterion of encouraging cost control and productivity improvement. However, with regard to capital investments, PEG-R notes that Union’s slower growth in net capital compared to EGD could signal a deferral rather than an efficient reduction of its capital spending under IR.

> **The Companies’ actual investment and system expansion experience under IR is more mixed. Customers have been added to the system less rapidly under IR than in the immediately preceding years, although this is not unexpected given that the 2008-10 period coincided with a recession. Similarly, net plant and equipment has grown less rapidly under IR than in 2005-06, although the deceleration has not been precipitous. A slower rate of capital investment would also be expected since the decline in economic activity reduces customer growth and, accordingly, the need to add capital to serve new customer needs. The slowdown in capital investment is potentially more of a concern for Union than EGD. It is possible that Union’s slower growth in net capital could signal the deferral rather than an efficient reduction of its capital spending under IR.**[66]

Further, PEG-R found that EGD did not satisfy all of the Board’s service quality requirements and that there were some downward trends in EGD’s service quality performance on some indicators.

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[64] OEB. EB-2007-0615/EB-2007-0606. Decision. March 11, 2008.
[65] OEB. EB-2011-0052. PEG-R. Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans. September 2011.
[66] Ibid. Page 5.

> **Overall, PEG-R concludes that Union is satisfying all of the Board's service quality requirements, but this is not consistently true for EGD. We are not in a position to assess why this is the case. Furthermore, we emphasize that the simple comparative analysis presented above should not be viewed as an example of "benchmarking." Any benchmarking analysis should attempt to control for differences beyond management control on a utility's measured performance, and such an analysis goes well beyond PEG-R's current assignment.**
>
> **Nevertheless, for the purposes of assessing the effectiveness of the IR plans, it is necessary to consider whether EGD and Union are providing appropriate service quality to their customers. This was one of the criteria that the Board said must be satisfied for any ratemaking framework to be effective. For EGD and Union, the Board has established standards for what it considers to be appropriate service quality on nine different service quality metrics. PEG-R concludes that Union is consistently satisfying these Board requirements, while EGD is not.[67]**

Most distribution components have long asset lives and deterioration as a result of diminished maintenance and/or investments, may not fully, if at all, manifest itself over the course of the IR term in which the maintenance and/or investment reductions were made. Therefore, the full impact of IRM on the service quality performance of the gas distributors has yet to be determined. As PEG-R points out:

> **Data on the service quality requirements are available for four years, from 2007 to 2010. This sample period exceeds the term of the EGD and Union IR plans by one year, but this is not a sufficient period of time to undertake meaningful comparisons of each utility's service quality performance before and after their IR plans have taken effect.[68]**

However, at this point in time there is concern that the Board's IR for the gas distributors has in the one case resulted in the deferral of capital investments and in the other case may be resulting in service quality performance deterioration.

5.3 OFGEM's Sustainable Network Regulation

The Office of Gas and Electricity Markets' ("Ofgem") experience with IR for network companies in the UK demonstrates how simple IR frameworks have had to evolve to address issues that the simple approaches failed to accommodate. Among the issues that have arisen is the need for capital investments. Ofgem also recognized

[67] Ibid. Page 120.
[68] Ibid. Page 115.

the need to evolve the quality performance incentives. Ofgem initiated IR earlier than the OEB and is significantly further along the learning curve than the OEB. Ofgem has recognized that its cost control regime must capture capital investment requirements and the integration of quality performance incentives to ensure sustainability and ongoing service value. Ofgem's lessons learned can serve the OEB well in its ongoing pursuit of IR. However, Ofgem does not regulate generation-only utilities and while there are conceptual parallels that can be drawn, its IR experience does not provide specific insight into IR for OPG.

The evolution of Ofgem's price control framework from RPI-X to RPI-X@20 is an epic illustration of a regulator addressing significant fundamental issues that are not accommodated in simple IR approaches. It is to Ofgem's credit that it has recognized and not shied away from the need to address the substantive issues facing the utilities, the resulting increased regulatory complexity, and the increased costs.

In 1990 Ofgem implemented its price control for network utilities using a simple RPI-X (i.e. inflation index minus productivity adjustment) approach.

In the consultation process for the 2005-2010 price control framework Ofgem asked the UK regional electricity distribution companies ("RECs") to provide forecasts of their 2005-2010 capital expenditure requirements to obtain an indication of what the RECs will need to spend to maintain service quality performance. Most of the RECs' forecasts indicated the need to increase capital investments with the scope of the required increases varying widely.[69] In recognizing the need for the increased capital investments in the 2005-2010 price control period OFGEM included a 48% average increase in allowed capital expenditures over the 5-year price cap term.

In 2008 Ofgem initiated RPI-X@20, a review to consider the ongoing appropriateness of its regulatory regime in light of the challenges facing the energy

[69] Ofgem. Electricity Distribution Price Control Review: Final Proposals. 265/04. November, 2004. Page 80.

network sector including: targets for tackling climate change; maintaining security of supply; and widespread maintenance and upgrading of aging networks.[70]

Ofgem refers to the new regulatory framework as Sustainable Network Regulation that is intended to address the “major challenges and opportunities, primarily driven by the need to decarbonise Britain’s energy sector, while maintaining a safe, secure and affordable system for existing and future consumers”.[71] Ofgem identified significant uncertainties that the network companies are facing related to:[72]

- The adaption of networks to the climate change agenda;
- The impact of the increase in financing costs due to the credit crunch and recent changes in the price of key input costs on the network companies’ outturn costs; and,
- The possible impact of the economic downturn that will impact load growth, cost of material, financing cost and inflation.

According to Ofgem, the RPI-X framework was not designed for the challenges that network companies are facing today and does not accommodate the nature and pace of change that the industry is facing. RPI-X@20 takes elements of the existing regulatory framework “that work well, adapted other elements to ensure they are focused on delivery of a sustainable energy sector and long-term value for money, and added elements to encourage the radical measures needed in innovation and timely delivery.”[73]

In addressing these concerns Ofgem reviewed the regulatory tools available for sharing risk associated with the uncertainties. The outcome of RPI-X@20 is the ‘Revenue using Incentives to deliver Innovation and Outputs’ (“RIIO”) model. RIIO is

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[70] Ofgem. Regulating Energy Networks for the Future: RPI-X@20. History of Energy Network Regulation. Overview. 13b/09. February 27, 2009.

[71] Ofgem. Regulating energy networks for the future: RPI-X@20 Recommendations Impact Assessment. Impact Assessment. July 26, 2010.

[72] Ofgem. Regulating Energy Networks for the Future: RPI-X@20. History of Energy Network Regulation. 13b/09. February 27, 2009.

[73] Ofgem Regulating energy networks for the future: RPI-X@20 Recommendations: Implementing Sustainable Network Regulation. Context. July 26, 2010.

an outcomes-led price control framework that includes pass through provisions, sharing factors, volume drivers and reopeners that are applied to categories of costs as appropriate.[74] Ofgem's Handbook for implementing the RIIO price control framework describes the model as follows:[75]

> **5.5. Under the RIIO model the price control will include details of the primary outputs network companies are expected to deliver (see Chapter 6) and will set revenue for efficient delivery of these outputs. This revenue commitment will comprise three elements:**
>
> - **base revenue to cover expected efficient costs (including financing costs) of delivering outputs and long-term value for money, including allowances for maintenance of, and investment in, capital assets and taxation (see Chapters 7 and 8);**
> - **adjustments to reflect company performance in delivering outputs efficiently and innovating to expose efficiencies during the control period (see Chapters 9 and 10); and**
> - **adjustments made during the control period for specified uncertainties that are considered to be outside the company's control but will have a significant impact on costs of delivery (e.g. compensation for changes in general price inflation in the economy) and changes to financial parameters that are updated during the period (e.g. annual adjustment to the cost of debt, pension adjustments) (see Chapter 11).**

Ofgem's RPI-X@20 provides an example of the integration of cost and service quality incentives. Ofgem incorporates consumer valuation of service quality determined through surveys and includes amounts of revenue for service quality performance. The two high-level objectives of the regulatory framework at the heart of the RIIO model are: sustainability of the network sector and long-term value of services provided.[76]

> **6.3. The objectives of the RIIO model are the cornerstone of the regulatory regime. The objectives are to encourage energy network companies to:**
>
> - **play a full role in the delivery of a sustainable energy sector; and**
> - **deliver long-term value for money network services for existing and future consumers.**

[74] Ofgem. Regulating Energy Networks for the Future: RPI-X@20. History of Energy Network Regulation. 13b/09. February 27, 2009. Page 45.
[75] Ofgem. Handbook for implementing the RIIO model. October 4, 2010. Page 29.
[76] Ibid. Page 32.

The scope of Ofgem's incentives around quality performance is substantial and illustrates the weight that Ofgem attaches to quality performance. Joskow[77] describes Ofgem's approach to service quality incentives for the UK RECs as involving several dimensions of performance with an overall penalty impact on revenue of about 4% while the reward impact is unlimited:

> **OFGEM has developed several incentive mechanisms targeted at various dimensions of performance. … Overall, about 4% of total revenue on the downside and an unlimited fraction of total revenue on the upside are subject to these quality of service incentive mechanisms.**

Joskow's description of how the quality incentives were developed indicates the significant effort and information that was required in Ofgem's integration of cost and quality incentives.

> **OFGEM uses statistical and engineering benchmarking studies and forecasts of planned maintenance outages to develop targets for the number of customer outages and the average number of minutes per outage for each distribution company. The individual distribution companies are disaggregated into different types (e.g. voltages) of distribution circuits and performance benchmarks and targets are developed for each based on comparative historical experience and engineering norms. Aggregate performance targets for each distribution company are then defined by re-aggregating the targets for each type of circuit (OFGEM (2004c) appendix to June 2004 proposals) to match up circuits that make up each electric distribution company. Both planned (maintenance) and unplanned outages are taken into account to develop the outage targets. The targets incorporate performance improvements over time and reflect, in part, customer surveys of the value of improved service quality. … OFGEM also has added cost allowances into the price control (p_0) to reflect estimates of the costs of improving service quality in these dimensions.[78]**

Ofgem's sustainable network regulation, RPI-X@20, builds on close to 20-years of IR experience. Like the RPI-X@20 regime, a regulatory framework for OPG would need to provide for the sustainability of OPG's assets and operations and service value in these times of significant and rapid energy policy, social (e.g. workforce renewal) and economic change. A comprehensive RPI-X@20 rather than a simplistic IR approach would need to be the start point for an IR framework for OPG.

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[77] Joskow, Paul L. Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks. Center for Energy and Environmental Policy Research. 05-014. September 2005. Page 51.

[78] Ibid. Pages 52-53.

In particular the emphasis on asset condition, quality performance and flexibility are key.

The OEB has a limited information base for the development of an IRM for OPG and has limited experience in its COS regulation of OPG's regulated assets. Further, there is an apparent absence of precedents of IR for generation-only utilities, and, there is a paucity in the OEB's IR approaches for the electricity and gas distributors. Learning based on Ofgem's RPI-X@20 review while contributing to a high level of understanding on the scope of factors that need to be accommodated, provides limited insight on IR development and implementation details that will address the long term sustainability of OPG's facilities and ongoing service value. This is especially so given OPG's complex nuclear generation safety performance considerations that preclude a simple IR trial and error learning approach as a start point. The U.S. NRC's concern reflected in its July 1991 policy statement on possible safety impacts of state regulators' economic performance incentives noted in section 5.1 above, attests to the concern with and lack of prudence of such an approach.

5.4 Lessons Learned from IR Experience

Some of the lessons learned from the U.S. experience on IR for nuclear facilities are that:

- Incentive programs did not result in an increase in efficiency performance;
- Incentive systems that may be more likely to enhance efficiency (i.e., focused incentive designs subject to a single performance criterion) may, in at least some contexts, adversely affect safety;
- Incentive programs featuring sharp thresholds between rewards and penalties may divert attention from safe plant operation; a reasonably broad null zone of acceptable performance in which no rewards or penalty could be imposed to minimize these effects;
- Incentive programs based on Performance Measurements that have short time intervals would encourage nuclear operators to focus on a short term

target or performance goals such as a higher capacity factor or availability factor. This target could become the primary focus, diverting attention from the long-term goal of reliability and operational safety; and,

- Incentive programs using performance measurements for long-intervals are better suited for the sound maintenance, operational and safety practices.

The lessons learned from the Board's experience with IR for the electricity distributors is that compromise in IR can lead to unintended and undesirable consequences. In particular, the Board's decision to use O&M benchmarking rather than total cost benchmarking has penalized distributors that are more efficient based on total cost and increased the capitalization of costs (e.g. labour). Further, the Board's implementation of the Incremental Capital Module ('ICM") has not been effective in addressing the issue of accumulating aging assets.

In the case of the Board's IR for the gas distributors, there appears to have been a deferral of capital investments in the case of Union while EGD did not satisfy all of the Board's service quality requirements and there were some downward trends in EGD's service quality performance. Given the long asset lives of the distribution components, the full impact of IRM on the service quality performance of the gas distributors has yet to be determined.

The lesson learned from Ofgem is the need to acknowledge and address major challenges and opportunities that the utilities' are facing as Ofgem is doing in its new regulatory framework in order to sustain the regulated assets and service value. A simplistic IRM approach for OPG would not be in line with sustainable regulation.

6 INFORMATION REQUIREMENTS

To help overcome regulatory information asymmetry regulators require utilities to provide information through Reporting, Record Keeping and Accounting Requirements ("RRR"). Over time, this information enhances the understanding of the utilities' costs in the regulatory forum. A broad information base is therefore a prerequisite for the development of an IR framework.

Information related issues that limit the development of an IRM for OPG are discussed in this section.

6.1 Information Gathering, Auditing and Accounting Foundation for IR

In a 2005 article Joskow addressed the importance of information gathering, auditing and accounting institutions, and the effective use of available information for the sound implementation of IR.[79] Joskow described the dependence of IR mechanisms on the availability of robust information and cautioned that the failure to recognize the importance of data can mar the effectiveness of the IR framework:

> **…, the sound implementation of incentive regulation mechanisms depends in part on information gathering, auditing, and accounting institutions that are commonly associated with traditional cost of service or rate of return regulation. These institutions are especially important for developing sound approaches to the treatment of capital expenditures, to develop benchmark for operating costs, to implement ratchets and resets of prices, to apply incentive regulation mechanisms to service quality attributes, and to deter gaming of incentive regulation mechanisms that have ratchets of one type or another.**
>
> **The failure to understand the role of this regulatory infrastructure, especially as it relates to data collection, accounting rules, reporting and auditing standards can significantly undermine the effectiveness of incentive regulation in practice.**

The first order for the Board in considering IR for OPG therefore, is the implementation of a robust and comprehensive annual information filing process that includes quality performance information (e.g. public, employee and operational safety).

6.2 Future Repercussions on OPG Information Confidentiality

As noted, the OEB's regulation of OPG, a generation-only utility, is anomalous with the general deregulation trend in the electricity industry. While the development of an IR plan requires a robust information base, should the Ontario Government evolve the IESO-administered electricity market to a fully competitive market there may be

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[79] Ibid. Page 3.

information disclosure on OPG's operations and costs required in developing an IRM that can disadvantage it in the competitive market. The OEB's confidential filing provisions may not mitigate this risk as it is unlikely that individuals privy to the competitively sensitive confidential information would not be influenced by the knowledge/insight gained should they be involved in the competitive sector in the future. Therefore, an issue that the Board needs to address in contemplating IR for OPG is whether IR information requirements may disadvantage OPG if Ontario's electricity market is evolved into a fully competitive market.

7 QUALITY PERFORMANCE INCENTIVES

A regulatory framework that includes incentives for cost efficiency, of necessity must include incentives for quality performance to ensure that IR's economic incentives do not result in quality performance deterioration. To understand whether IR has resulted in cost efficiency gains (i.e. lower costs for same quality performance) rather than irrational cost cuts (i.e. lower costs that result in lower quality performance) the ability to assess the implications of IR on service quality performance is critical. Quality performance regulation is therefore an essential part of an IR framework.

In a September 2005 article on incentive regulation theory and application, Joskow speaks to the incentive of pure price cap mechanisms to reduce both costs and quality of service.[80]

> **…it is widely recognized that a pure price cap mechanism provides incentives to reduce both costs <u>and</u> the quality of service (Banerjee 2003). Accordingly, price cap mechanisms are increasingly accompanied either by specific performance standards and the threat of regulatory penalties if they are not met or formal PBR mechanisms that set performance standards and specify penalties and rewards for the firm for falling above or below these performance norms (OFGEM 2004d, 2004f; Sappington 2003; Ai and Sappington 2004; Ai, Martinez and Sappington 2004).**

Further, Joskow observed that there has been a shift of focus from reducing operating costs to investments and service quality, but that service quality

[80] Ibid. Page 37.

considerations appear to be just added to cost reduction mechanisms rather than integrated into the IRM.

> **As incentive regulation has evolved in the UK and other countries, the portfolio of incentive mechanisms that is being utilized has grown. While the initial focus was on reducing operating costs it has now shifted to investment and various dimensions of service quality. Ideally these mechanisms should be fully integrated and differences in the power of the individual incentive schemes carefully considered. [Page 83-84]**
>
> **… Quality of service schemes appear to have been bolted on to schemes designed to provide incentives for cost reduction and do not effectively incorporate information on consumer valuations of quality and the costs of varying quality in different dimensions.[81]**

Joskow noted the complexity of the theoretical relationship between operating expenditures, capital expenditures and quality performance over time and space[82] and observed that in practice the integration of cost-control and quality-related incentives remains a challenge for IR:[83]

> **.., integrating these incentive mechanisms into a package that gives the correct incentives on all relevant margins remains a considerable challenge for incentive regulation in practice.**

In a more recent article Joskow (2008) noted that the stronger the incentive to reduce costs, the greater the incentive to reduce quality when cost and quality are correlated. According to the author, price cap mechanisms have been increasingly accompanied by a set of performance standards and associated penalties and rewards for performance below and above the standards.[84]

In the UK, incentive regulation covers various dimensions of service quality to provide incentives for the distributors to maintain or enhance quality performance including guaranteed standards that provide protection to individual customers. If a Distribution Network Operator fails to meet a guaranteed standard it must make a payment to the customers affected, subject to certain exemptions. The standards

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[81] Ibid. Pages 83-84.
[82] Ibid. Page 49.
[83] Ibid. Page 51.
[84] Joskow, Paul L. Incentive Regulation and Its Application to Electricity Networks – Review of Network Economics. Vol 7, Issue 4 – December 2008.

cover areas such as supply restoration following power cuts and estimation of charges for connections.[85]

7.1 Quality Performance for Nuclear Generation

With the much higher degree of technical and operating complexity of nuclear generation compared to networks, the integration of cost and quality incentives for OPG can be expected to be exceedingly challenging, if not daunting. However, ignoring quality performance in a compromised IR approach is not an option given the risk of negative outcomes as a result of an imperfect IR approach. Should OPG's quality performance be negatively impacted as a result of failure to integrate cost and quality performance incentives, the result can be dire for Ontario's electricity market with consequential economic and bill impacts, and possibly employee and even public health and safety implications. While such consequences would be unintentional, they are nevertheless possible outcomes of flawed IR incentives and the risks must be considered.

There is undisputable recognition that safety is a dominant aspect of any organization in the international nuclear industry. This is founded on the awareness of the significant destructive capability of nuclear power when control is lost, and the recognition that strict attention to safety is essential if the benefits of this form of power are to be obtained.[86]

Consistent with this recognition, the CNSC endorses the general nuclear safety objective which stipulates that nuclear power plants must be designed and operated so as to protect individuals, society and the environment from harm by establishing and maintaining effective defences against radiological hazards in nuclear installations.[87]

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[85] Ofgem's website http://www.ofgem.gov.uk/Networks/ElecDist/QualofServ/Pages/QualofServ.aspx
[86] International Atomic Energy Agency. Safety culture in nuclear installations. Guidance for use in the enhancement of safety culture. December 2002. Page 8.
http://www-pub.iaea.org/MTCD/publications/PDF/te_1329_web.PDF
[87] Canadian Nuclear Safety Commission. RD-337: Design of New Nuclear Power Plants.

The nuclear industry in Canada uses the defence-in-depth approach which is applied to all organizational, behavioural, and design-related safety and security activities to ensure that they are subject to overlapping provisions. Under this approach, if a failure were to occur it will be detected and compensation made, or it would be corrected. This approach is applied throughout the design process and operation of the plant to provide a series of levels of defence aimed at preventing accidents, and ensuring appropriate protection in the event that prevention fails. No nuclear facility should have pressure to reduce costs that would in any way minimize this process.

Of relevance is the US nuclear generation experience described in section 5 with respect to the impact that the use of economic performance incentives may have on safety and the NRC's concern that in the interest of short-term economic benefit, nuclear operators may rush work, take short cuts, or delay a shutdown for maintenance.

It is imperative that a broad-based IR program integrate safety as a key quality performance measure(s) with appropriate standards and incentives to discourage the compromise of safety. Doing so would also address Joskow's concern that the stronger the incentive to reduce costs, the greater the incentive to reduce quality (e.g. safety) when cost and quality are correlated.

Similarly, it is imperative that targeted IR programs take into consideration implications that may affect nuclear power plant safety and must therefore include standards and incentives for safety performance measures. Indeed the NRC's concern on the effect of IR on safety was focused on targeted programs. The NRC's concern was that an incentive program could directly or indirectly encourage a nuclear operator to maximize measured performance at the expense of plant safety. According to Martin et al[88] a New York Public Service Commission's 1987 proposal to use the NRC's Systematic Assessment of Licencee Performance ("SALP")[89]

[88] Martin, R.L., Baker, K., and Olson, J. Incentive Regulation of Nuclear Power Plants by State Regulators. Pacific Northwest Laboratory. Battelle Human Affairs Research Center. NUREG/CR-4911. PNL-7596. February 1991. Page 1-5.

[89] The SALP program covered the following four functional areas: Operations, Maintenance, Engineering, and Plant Support.

ratings and enforcement programs as the basis for incentives in an IR program raised the NRC's concerns that the focus of the SALP may shift from the underlying issues to concerns on the financial incentives:

> **The prospect of financial rewards or penalties for a utility based on SALP ratings is one of the issues that concerns the NRC, because the focus of the SALP process may shift from the underlying issues to the numerical ratings. The NRC's SALP program was primarily developed to assist the NRC in determining the best allocation of its inspection resources. Based on the NRC's perception of licensee performance, the SALP program identifies nuclear units and program areas that need the most attention. In any particular SALP report, specific areas may be added or deleted based on site-specific considerations. The NRC staff focuses on the issues identified in the SALP report and apparent root causes of problems. The NRC is concerned that the safety of the unit could be adversely affected if the issues identified in SALP reports are obscured because of concerns over the financial consequences incurred as a result of specific SALP ratings.[90]**

As noted in section 5, the NRC's 1991 policy statement[91] was issued as a result of its concern regarding the impact that incentive programs may have on safety.

7.2 CNSC Safety Performance Assessment

The object of the CNSC set out in the *Nuclear Safety and Control Act* includes the following:

> **…to regulate the development, production and use of nuclear energy and the production, possession and use of nuclear substances, prescribed equipment and prescribed information in order to**
>
> **(i) prevent unreasonable risk, to the environment and to the health and safety of persons, associated with that development, production, possession or use,**
>
> **(ii) prevent unreasonable risk to national security associated with that development, production, possession or use, and**
>
> **(iii) achieve conformity with measures of control and international obligations to which Canada has agreed…[92]**

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http://www.nrc.gov/reading-rm/doc-collections/gen-comm/admin-letters/1998/al98007.html

[90] Martin, R.L., Baker, K., and Olson, J. Incentive Regulation of Nuclear Power Plants by State Regulators. Pacific Northwest Laboratory. Battelle Human Affairs Research Center. NUREG/CR-4911. PNL-7596. February 1991. Page 1-5.

[91] Nuclear Regulatory Commission. 56 FR 33945. Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement. July 1991.

[92] Nuclear Safety and Control Act (S.C. 1997, c. 9). Section 9. http://laws-lois.justice.gc.ca/eng/acts/N-28.3/index.html

There are a number of stages in the lifecycle of nuclear facilities (preparation of a site, construction, operation, decommissioning or abandonment). To perform an activity in any of these stages, companies must obtain a licence from the CNSC. A separate licence is required for each stage. CNSC licensing of nuclear power plants is comprehensive and covers 14 separate issues referred to as safety and control areas ("SCAs"), such as radiation protection, emergency preparedness, environmental protection, and equipment fitness for service.

The CNSC monitors and verifies compliance of the nuclear power operators with their licence obligations. It does so through on-site inspections of operations and overseeing activities at each nuclear station on a day-to-day basis.[93]

The CNSC reviews all items of non-compliance and follows up to ensure all items are quickly corrected. Every year, it publishes a report on the safety performance of nuclear power plants. This report covers safety performance ratings for each SCA at each nuclear station against relevant requirements and expectations. The ratings are determined using the findings made throughout the year during inspections, as well as the review of desktop analyses, events and performance indicators. The findings are categorized into appropriate SCAs and assessed against a set of performance objectives developed for each SCA.[94]

7.3 Integrating Quality Performance into an IR Framework for OPG Nuclear Facilities

The PA Report stated that since nuclear safety standards cannot be compromised without risk of a CNSC fine or nonrenewal of licence, nuclear safety would not be an appropriate target for quality performance incentive. London Economics expressed similar views at the stakeholder meeting. The PWU is of the view that the fact that the CNSC has nuclear safety oversight and that CNSC nuclear safety standards cannot be compromised does not preclude the need to include safety quality

[93] CNSC's website http://nuclearsafety.gc.ca/eng/licenseesapplicants/powerplants/index.cfm
[94] CNSC Staff Integrated Safety Assessment of Canadian Nuclear Power Plants for 2010. Info-0823. http://nuclearsafety.gc.ca/pubs_catalogue/uploads/2010-CNSC-NPP-Safety-Report-INFO-0823_e.pdf

performance measures in an IR regulatory framework for OPG to discourage any inadvertent compromise of safety performance. At minimum, such measures should discourage nuclear generators from reducing their safety margins and managing closer to or at the nuclear regulator's safety standards. In addition, performance measures would be required that would discourage nuclear generators from indirectly influencing a utility's approach to reactor safety issues in situations not covered under CNSC licence conditions.

In regulating natural monopolies such as network utilities, there may be a margin of risk related to IR shortcomings in the integration of cost and quality that can be tolerated and corrected over time without significant safety consequences. However, given the NRC's safety concerns with State regulators' IR for utilities with nuclear generation, any tolerance of risk related to a safety performance measure for OPG should not be taken for granted. The OEB should be sensitive to the criticality of including standards and incentives for safety performance in an IR approach for OPG. Unfortunately, not only does the OEB lack experience in the integration of cost and quality incentives in its existing IR frameworks for electricity and gas distributors, it also lacks experience in the review of any OPG nuclear generation safety performance measures and in developing standards and incentives for such measures.

The Board also needs to consider that with the long lifetimes of generation assets, there would likely be a lag in the manifestation of any reduced performance that results from cost cuts made over the course of an IR plan. The eventual future quality performance deterioration may therefore not be traceable cost cuts made under IR today. Integrating cost and safety performance incentives will proactively discourage a generator from making cost cuts that will negatively impact future quality performance.

Should the Board persist with its desire to implement IR for OPG, the PWU recommends the inclusion of safety performance measures. However given the complexity of nuclear generation, the PWU recommends that the safety performance measures, standards and incentives should be developed by OPG. Measures and targets that are included in OPG's business plan would be the most practical to adopt and would provide reasonableness to the targets. The benchmark therefore would be OPG's historic performance which precludes all the challenges, limitations and implicit error described by Harbourfront at the stakeholder meeting, that might arise when assessing and modeling OPG's performance using external benchmarking.

The PWU identifies the need for the Board and OPG to communicate with the CNSC on the IR framework, so that the CNSC can be vigilant with regard to any possible safety issues related to the IR framework. This is analogous to the NRC's policy statement intent. As a matter of fact, the PWU is of the view that the CNSC ought to be apprised of the current consultation process so that the CNSC has the opportunity of reviewing the IR options for OPG and share its views with respect to any implications that the options may have on nuclear safety.

The PWU also recommends that as part of the annual assessment of OPG's safety performance the CNSC should oversee and monitor OPG activities that have direct or indirect implications on the safe operation of OPG's nuclear facilities (e.g. modification of programs and delays in maintenance) that may be related to the Board's IR framework.

Furthermore, the PWU submits that the Board would need to retain nuclear expertise if it is to apply IR to OPG Nuclear. As Harbourfront noted, commission staff in the US, who could be nuclear experts, bring in other nuclear experts from the outside as well as statisticians to bring credibility to the analysis conducted.

7.4 Integrating Quality Performance into an IR Framework for OPG Hydroelectric Facilities

The PWU submits that a proper IRM for OPG's hydroelectric prescribed assets should include a quality performance component covering safety and environmental performance standards.

Safety performance for OPG's Hydroelectric Business Unit involves employee safety and dam and waterways public safety. Consistent with its mandate and corporate objectives, OPG's objectives for its Hydroelectric Business Unit include:[95]

- Striving for continuous improvement in the areas of dam and waterways public safety and environmental performance.
- Maintaining the existing excellent employee safety record (top quartile performance).

OPG has programs based on the Canadian Dam Association ("CDA") – Dam Safety Guidelines (2007) and other industry guidelines that are in many respects seen as a model for emerging standards and regulatory requirements. OPG's policy statement with respect to the Dam Safety Policy includes the following:

> **Ontario Power Generation dams shall be designed, constructed, operated and maintained in a safe manner which will comply with all Regulatory requirements.**
>
> **In the absence of Regulatory requirements, the dams shall be prudently managed, taking into consideration best practices as recommended in the Canadian Dam Safety Guidelines published by the Canadian Dam Association and other appropriate International practices.**[96]

With respect to public safety, OPG's Hydroelectric Business Unit has developed a number of technical documents concerning public safety around dams, and material to educate the public and raise awareness of the hazards associated with the operation of dams and hydroelectric facilities. According to OPG both the Ministry of Natural Resources and the CDA are using the work developed by OPG in developing provincial and national guidelines for public safety around dams.[97]

Safety and the environment are of highest priority at OPG. As reported in EB-2010-0008, OPG's Hydroelectric Business Unit uses a structured portfolio approach to

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[95] Ontario Power Generation. Prefiled Evidence. EB-2010-0008, Exhibit A1, Tab 4, Schedule 2. Page 5 of 14. http://www.opg.com/about/reg/filings/paymentamounts/files/Exhibit%20A%20-%20Administrative%20Documents/A1-04-02_Overview%20of%20Regulated%20Hydroelectric%20Facilities.pdf
[96] Ontario Power Generation's Dam Safety Policy. OPG-POL-0005. http://www.opg.com/pdf/Dam%20Safety%20Policy.pdf
[97] Ontario Power Generation. Prefiled Evidence. EB-2010-0008. Exhibit A1, Tab 4, Schedule 2. Page 12 of 14.

identify and prioritize projects for its investment program. The cornerstone of this planning approach is that safety, environmental, and other regulatory programs are of the highest priority compared to production and reliability initiatives.

As part of the business planning process for hydroelectric operations, OPG has hydroelectric key performance targets including employee safety and environmental performance.

For employee safety, OPG uses accident severity, defined as the number of days lost by employees injured on the job divided by 200,000 hours worked. This metric is used by other electric utilities and is benchmarked by the Canadian Electrical Association ("CEA"). OPG uses hydroelectric benchmarks for safety performance to assess and understand the performance of its stations, as well as to identify and share best practices and opportunities for improvement.

In measuring environmental performance OPG uses an Environmental Performance Index to measure the environmental performance of the regulated facilities. OPG defines the Environmental Performance Index as follows:

> **The environmental performance index ("EPI") includes a variety of measures and deliverables, some that are specific targets (such as minimizing the number of spills and MOE infractions) and some that are environmental enhancements (such as energy efficiency). The EPI target is 1.0. An EPI above 1.0 can only be achieved if the number of spills and infractions are less than target, and/or the number of energy efficiency initiatives is better than planned.**[98]

If the Board is intent on pursuing IR for OPG Hydroelectric, the quality performance targets that OPG already has in place can be used as IR quality performance targets. Using these targets will provide realistic expectations. OPG will already have a data base available on its historic performance and the measures are ready for implementation in an IR framework.

[98] OEB. EB-2010-0008. Prefiled Evidence. Exhibit F1, Tab 1, Schedule 1. Page 10 of 24.

8 IRM OPTIONS FOR OPG'S PRESCRIBED NUCLEAR FACILITIES

In this section the PWU comments on IRM options for OPG's nuclear facilities proposed by PA and London Economics.

8.1 Power Advisory IRM Options For OPG's Prescribed Nuclear Facilities

PA presents six IRM options (N1 to N6) for OPG's prescribed nuclear facilities.

Options N1 through N4 involves assumptions based on the ScottMadden benchmarking study. At the stakeholder meeting Harbourfront described the substantive sources of error in benchmarking nuclear performance. Harbourfront indicated that in applying the results of a benchmarking study, the error implicit in the study must be taken into account. Therefore, the results of the ScottMadden study cannot be taken holus-bolus to form assumptions or set targets for OPG's nuclear facilities as proposed by PA.

The PWU's comments on each of the options are provided below.

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

In PA's Option N1, the X-factor is derived using an industry forecast Total Factor Productivity ("TFP") growth factor and a benchmark factor. It is assumed that a "typical firm" in the industry would be able to, at minimum, improve its productivity by the industry forecast TFP growth factor. OPG's performance would be compared to the industry standard and OPG would be held to a higher or lower standard depending on its past performance relative to the industry benchmark.

PA points out that estimating TFP is challenging because of the difficulty of obtaining the necessary data. PA suggests that if focused studies are not available, this option can be pursued using "whatever sources are available for estimated TFP growth and for indication of the relative performance of OPG Nuclear".

In reference to the Pickering Units, PA states that they were identified in a benchmarking study as capable of achieving improvements in performance. PA makes this statement in the absence of any critical analysis of the nuclear benchmarking study. As noted earlier, Harbourfront points out that nuclear performance benchmarking study results should not be applied without a thorough understanding of the limitations.

In any case, the PWU would point out, as PA does for its N2 option, that the results of the benchmarking study have been factored into OPG's business plan.[99] As such, any IR approach that depends on the benchmarking study would need to take into account that movement towards the benchmark is factored into OPG's base payment amounts. The PWU agrees with PA that the Board's review should test whether the targets in the business plan provide enough of a challenge or whether higher targets should be set.

The PWU submits that the X-factor is the benchmark that provides the key cost incentive. If there is a lack of clarity on how the utility's circumstances relate to the benchmark, the incentive created will not be transparent and the outcome will be uncertain.

Furthermore, there are no quality performance requirements included in N1 that would act as a backstop to quality performance (e.g. employee safety; operational safety) deterioration that can result from OPG's pursuit of IR's economic incentive.

PA states that "the ability to operate these plants safely has not been called into question". Furthermore, PA states that with regard to safety, the CNSC will continue to require safe operations as a condition of licence. However, in the paper on IR of nuclear power plants by state regulators described in section 5.1 above, Martin et al (1991) noted that economic regulation and nuclear performance incentives may have the potential to indirectly influence a utility's approach to reactor safety issues in situations not covered in licence conditions.[100] Questions have been raised as to whether imperfect incentive programs lead utilities to unknowingly act against the

[99] Ibid. Exhibit F2, Tab 1, Schedule 1.
[100] R.L. Martin, Baker, K., and Olson, J. 1991. Incentive Regulation of Nuclear Power Plants by State Regulators. Pacific Northwest Laboratory. Battelle Human Affairs Research Center. NUREG/CR-4911. PNL-7596. Page 1-4.

public interest or adversely affect public health and safety.[101] N1 will undoubtedly result in an imperfect IRM and risks outcomes that are not in the public interest. While any safety risk should by principle always be avoided, in the case of nuclear generation the possible consequences requires maintaining a significant margin below the safety regulation requirements.

On top of the issues discussed above, N1 lacks specific reference to an incremental capital module, an earnings sharing mechanism and a Z-factor. In the PWU's view, given the overwhelming challenges that comes with N1's shortcomings, it is not a plausible or prudent IR option for OPG.

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

In PA's Option N2 productivity improvements are based on a measured or perceived gap between OPG's performance and industry targets for one or several performance indicators (e.g. cost per MWh; Forced Loss Rate). The decrease in revenue requirement would represent the cost reduction required to narrow the gap with industry targets. PA suggests that the benchmarking study and compensation study that the Board directed OPG to file in its next payment amount application form the basis for the determination of reasonable targets. However, PA also suggests, and the PWU agrees, that OPG's Nuclear Business Plan, which would incorporate feasibility and draws on the benchmarking and compensation studies, is an initial source for appropriate targets. The PWU agrees with PA that the Board review can then test whether these targets provide enough of a challenge or whether higher targets should be set.

Targets included in the business plan are based on OPG's expert judgement and would provide realistic targets. Setting the targets too high or too low comes with the risk of perverse outcomes. In the case of nuclear facilities, such risk should not be taken. Therefore, to ensure that the performance indicators and targets are appropriate for OPG, it should be left to OPG to propose the targets.

[101] Ibid. Page 1-2.

With the impacts of cost cuts at U.S. nuclear plants described in section 5.1, appropriate quality performance standards and incentives (i.e. rewards and penalties) are essential. Therefore, in considering option N2, the Board should make the targets implicit in OPG's business plan the basis for the IR adjustments and build incentives for quality performance targets around them. N2 would need to provide for a Building Block approach to provide for OPG's capital investments and address uncertainties discussed in section 4 over the IR term. As well a Z-factor and earnings sharing mechanism would need to be included.

8.1.3 Option N3. Price Cap with Initial Price Based on Efficiency Improvements

PA's Option N3 makes cuts to OPG's cost of service revenue requirement as a means of imposing efficiency in the initial year. Other than the efficiency improvement requirements for the initial year, the approach is similar to N2 and uses comparative information from a benchmarking study to create incentives for OPG Nuclear to improve performance. The shortcomings of N2 described above therefore apply to N3.

Further, in setting initial rates in N3, OPG would be disallowed costs found to be just and reasonable in the cost of service review. To disallow costs found to be just and reasonable would constitute a fundamental error in rate setting.

In PA's view the Board made a comparable adjustment to initial year prices in reducing OPG's proposed revenue requirement in EB-2010-0008 based on a reduction in staff costs of $55M for 2011 and $90M for 2012. PA notes that the Board expressed some doubt that the cost reductions could be achieved. Further, PA notes the Board's implicit understanding that failure to achieve cost reductions would result in a lower ROR for the shareholder.

To avoid irrational cost cuts as a result of cuts to initial rates, OPG would need to reduce its ROR to a level below the Board-allowed ROR. This would increase OPG's financial risk with possible repercussions for ratepayers.

Not only does this option involve unjust and unreasonable cuts to the base rates it comes with all shortcoming identified for N2. Therefore, it is not a reasonable IR option for OPG.

8.1.4 Option N4. Specific Performance Targets

PA's option N4 contemplates the addition of specific performance targets (e.g. Unit Capability Factor or Forced Loss Rates) for poor performing nuclear units in addition to a price cap IRM (i.e. Option N1). The payments would be increased to provide greater rewards for higher achievement, effectively increasing OPG Nuclear's incentive to improve the performance of those units.

PA suggests that a targeted mechanism could also be used for performance of employee and public safety such as the 2-Year Industrial Safety Accident Rate used by the World Association of Nuclear Operators' Nuclear Performance Index. While PA recognizes in this option that this kind of target is used in IRM or COS to ensure that the utilities do not respond to cost reduction incentives by reducing quality performance, it has not included such targets in its other two price cap mechanism options, N1 and N2.

The PWU's comments on N1 apply to this option and as such it is not a reasonable IR option for OPG.

8.1.5 Option N5. IRM for DRP Capital Expenditure

PA states that in the Board's EB-2010-0008 decision it expressed interest in discussing possible performance incentives for the Darlington Refurbishment Project ("DRP"). PA suggests that a possible benchmark for the DRP would be the degree to which the actual DRP costs track OPG's original estimate. Another option forwarded by PA is to encourage OPG to reflect incentives in contracts with key vendors, including the Engineering, Procurement and Construction ("EPC") vendor in a DRP incentive that provides OPG with the opportunity to share in cost savings or incur a penalty for cost increases and delays. However, PA acknowledges that this option raises contract confidentiality concerns and that it would need to be implemented in a manner that preserves confidentiality.

It is not clear, to what extent the costs and timeliness of the DRP is in the control of OPG. To the extent that there are components of the DRP that are in OPG's control, the Board should consider whether cost and time incentives are appropriate for the DRP. In the refurbishment of nuclear units, as with any work on these units, the costs and time would not only relate to the complexity of the process (e.g. maintenance, repair, refurbishment) but also to maintaining a safe working environment. While there are health and safety legislative requirements, OPG's policy is to also meet internal and external standards to which it subscribes with the objective of moving beyond compliance.[102] Incentives for cost and timing cuts may result in cuts to safety precautions/performance levels that are beyond compliance levels. This is not acceptable as it increases worker safety risk. Furthermore, given the complexity of the DRP, the Board would want to avoid inadvertently creating cost and time pressures that result in errors.

If the Board wishes to consider performance targets for the DRP, the Board should seek input from OPG on a reasonable IRM for a DRP performance target.

8.1.6 Option N6. Earnings Sharing Mechanism

PA's option N6 is an earnings sharing mechanism which is a component of an IR option rather than an IR approach.

An earnings sharing mechanism is an appropriate approach to the sharing of risk between the shareholders and ratepayers over the course of an IR term related to the correctness of the X factor. If the Board is determined to implement IR for OPG, a sharing mechanism should be included in the IRM.

8.2 London Economics IRM Options For OPG's Prescribed Nuclear Facilities

London Economics proposes and recommends a variant of PA's N2 option: N2 with an embedded productivity target (i.e. Building Block approach). According to PA Option N2 is plausible when restricted to OM&A and normal capital expenditures.

[102] OPG 2012 Health & Safety Policy. http://www.opg.com/pdf/H&SPolicy.pdf

London Economics says that building blocks can help accommodate capital expenditures that require “smoothing” due to changes in output resulting from long term maintenance and refurbishment outages. London Economics is of the view that the N2 option may be the only practical option given the obstacles to an empirical, TFP-based price cap.

The PWU notes that London Economics’ variant of option N2 lacks quality performance requirements (e.g. safety) as a backstop to the pursuit of efficiency gains at the expense of quality performance.

London Economics also suggests another alternative to N1 (TFP) and N2: a price cap as a percentage of inflation in lieu of a more explicit productivity target. In the PWU’s view, this arbitrariness in setting IRM is not acceptable as it lacks transparency on the incentives and possible outcomes.

With regard to the timing for applying an IRM, London Economics suggests that an IRM can be implemented for OPG’s hydroelectric prescribed facilities first. According to London Economics, the lessons to be learned in implementing 1st Generation IRM for OPG’s prescribed hydroelectric assets can be used in determining the payment amounts of the output of OPG’s nuclear assets. However, OPG goes further and proposes to continue on COS until the completion of the DRP and Pickering stations are out of service.

Given that OPG expects a significant nuclear output reduction due to refurbishment outages of its nuclear fleet over the next 12 years, an IRM to be applied to OPG nuclear business will not be fulfilled in a steady state environment. On that basis, the PWU submits that OPG’s proposal to continue on COS until the completion of the DRP and Pickering stations are out of service is reasonable. However, the PWU is not convinced that IR is appropriate for OPG Nuclear even at that point.

8.3 PWU Conclusion on IR Options for OPG Nuclear

The lack of industry and/or OPG information for PA’s proposed NI, N2, N3 and N4 options will result in imperfectly informed IR approaches that can result in unanticipated negative outcomes. Cost and time pressures on the DRP that result from N5 can result in the compromise of quality and worker safety. In addition the large components of the DRP will be contracted and will not be in the direct control of OPG. N6, an earnings sharing mechanism, is a component of an IR framework rather than an IR option.

With the exception of N4, the options do not include quality performance targets and incentives (e.g. safety) as a backstop to the pursuit of cost performance at the expense of quality performance. Furthermore, all of PA's six IR options for OPG Nuclear are incomplete IR frameworks. As a consequence, none of PA's IR options for OPG Nuclear are credible options.

The PWU believes that given the inordinate IR design challenges, the significant uncertainties that OPG faces, the impacts of which are unknown in the context of IR incentives, and the possible unanticipated deleterious impact on nuclear safety, it is not appropriate to use an IR approach to regulate OPG. On that basis the PWU supports OPG's proposal to continue on COS until the completion of the DRP and Pickering stations are out of service.

Should the Board persist with its desire to regulate OPG using IR despite the unsuitability of doing so, the least risky approach would be to base the IR framework on OPG's business plan which would incorporate all essential consideration of reliability and safety and avoid the inadvertent outcome of flawed IR expectations.

Such an approach might be based on the following:

- Initial payment amounts for the IR term, $P_{0,}$ are set in the COS review;
- As part of its COS payment amounts application OPG files:
    - A 5-year business plan, including forecast annual nuclear budgets (adjusted for inflation) and performance targets for each year that incorporate efficiency gains;
    - Estimates of the annual efficiency gains incorporated in the business plan;
    - A proposal on IR quality performance metrics (e.g. employee safety; nuclear safety) including targets and incentives;

- Annual payment amount IR adjustments are based on the efficiency gains implicit in OPG’s business plan and the change in the Board’s cost of capital provisions;
- Performance targets and efficiency gains are embedded in the forecast of future operating and capital costs that are used to forecast the revenue requirement and the rate schedule for each year within the IR plan (i.e. Building Block approach).
- Quality performance metrics, targets and incentives are proposed by OPG based on its business plan and performance is reported annually;
- The IR framework includes an earnings sharing mechanism;
- The IR framework includes a Z factor; and,
- The IR Building Block framework provides for variance accounts to accommodate variances between forecast and actual amounts related to economic and market uncertainties

Given CNSC’s authority with regard to nuclear safety, the CNSC should be informed of the proposed IR framework to give it the opportunity to comment on the proposal. The IR framework approved by the Board should be communicated to the CNSC so that it is aware of the performance pressures that the IR framework imposes on OPG and the areas of OPG Nuclear’s operations for which it might need to increase its monitoring efforts.

OPG’s business plan should be the basis for determining performance targets. Asset condition and historic performance will provide adequate basis for setting the proper targets, precluding the challenges, limitations, and the implicit error when evaluating and modeling OPG’s performance using external benchmarking.

9 IRM Options For OPG’s Prescribed Hydroelectric Facilities

In this section the PWU discusses IRM options for OPG’s prescribed hydroelectric facilities proposed by PA and London Economics.

9.1 Power Advisory IRM Options For OPG's Prescribed Hydroelectric Facilities

PA presents six IRM options (HI to H6) for OPG's prescribed hydroelectric facilities. The following are the PWU's comments on the options.

9.1.1 Option H1. Extend and/or Modify the Existing HIM

PA's Option H1 extends and/or modifies OPG's existing Hydroelectric Incentive Mechanism ("HIM"). The HIM is an incentive that encourages the use of Sir Adam Beck PGS to leverage the water flows and shift production from low price hours to high price hours.

PA notes the Board's concern that the current HIM may be too generous to OPG. According to PA this concern appears to be driven in part by two factors that are largely beyond OPG's control: (1) the level of the Hourly Ontario Energy Price ("HOEP") relative to OPG's approved payment level; and, (2) the interrelationship between the HOEP and the Global Adjustment ("GA"). While the HIM includes a sharing mechanism, PA suggests that these circumstances can be addressed more broadly through an earnings-sharing mechanism that is applied to earnings after consideration of all factors within and beyond (e.g. SBG) OPG's control, and that reflect the impact of all incentive measures.

H1 would retain OPG's obligation to demonstrate that it has maximized its pumping activities during SBG conditions and would compensate OPG for lost production related to spilling water under SBG by exempting OPG from the Wholesale Market Service Charge for pumping operations.

The PWU notes that in its decision in EB-2010-0008 in which the OEB found that the existing structure of the HIM did not provide sufficient benefits to customers,[103] it allowed OPG to incorporate only a portion of the HIM revenue forecast into its revenue requirement instead of the full amount:

> **In recognition of the potential interaction between SBG and HIM, the Board will only incorporate a portion of the HIM revenue forecast into the revenue**

[103] OEB. EB-2010-0008. Decision. March 10, 2011. Pages 146-147

requirement: $5 million for 2011 and $7 million for 2012. The Board also directs OPG to establish a variance account to track all additional HIM net revenues above this forecast provision.[104]

In addition the OEB directed OPG to review the HIM structure in its next payment amounts application.

The Board also directs OPG to re-address the HIM structure in its next application. Specifically, the Board expects OPG to provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market.[105]

The PWU submits that consideration of H1 should be in the context of the Board's direction in EB-2010-0008 and reviewed in the proceeding on OPG's next payment amount application. This will allow for the assessment of this option based on comprehensive analysis conducted by OPG as provided for in the Board decision.

9.1.2 Option H2. Shaping the OPG Hydroelectric Payment

In Option H2 PA proposes introducing shaped payment prices which would include a peak price for the production from the Sir Adam Beck PGS. The PWU submits that this option is a rate structure option. There are attributes of a sound rate structure that go beyond the design of an IRM that would need to be considered based on comprehensive rate research.

Furthermore, the PWU submits that in EB-2007-0905 OPG provided reasons why pricing Sir Adam Beck PGS output cannot be considered separately from the pricing of the other Sir Adam Beck facilities. At that time OPG submitted the following:

Sir Adam Beck PGS was designed and built for integrated operation with the other two Sir Adam Beck plants. Integrated operation of Sir Adam Beck PGS with the other Sir Adam Beck plants makes economic sense, optimizes peaking capability, allows OPG to efficiently provide automatic generation control and operating reserve at Sir Adam Beck II (see Ex. G1-12 T1-S1 for a discussion of these services), provides safety and system related benefits and is important in the control of the diversion of the Niagara River at the Sir Adam Beck complex. To sever Sir Adam Beck PGS operation from the rest of the Sir Adam Beck facility by developing its payment amounts separately from Sir Adam Beck I and Sir Adam Beck II would distort the incentives that

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[104] Ibid. Page 147.
[105] Ibid. Page 148.

> **currently exist and negatively impact the efficiency with which the Sir Adam Beck PGS performs the valuable roles required by the power system.**
>
> **…**
>
> **The supply of water to both OPG and New York Power Authority ("NYPA") plants is managed on an hourly basis by the Niagara River Control Centre, which identifies the water available for the entire Sir Adam Beck complex (including Sir Adam Beck PGS), and the NYPA plants. The operation of the Sir Adam Beck PGS has a direct impact on production from the downstream facilities of Sir Adam Beck 1 I and Sir Adam Beck II and vice versa. For example, an increase in Sir Adam Beck PGS output necessitates an increase in output at either Sir Adam Beck I or Sir Adam Beck II in order to maintain water elevation control at various locations including the Sir Adam Beck I and Sir Adam Beck II headponds and the cross-over (see Ex. A1-T4-S2 for a more detailed discussion). Similarly, a reduction in Sir Adam Beck PGS output would necessitate a reduction in Sir Adam Beck I or Sir Adam Beck II output simply because there would be less water flowing to these stations and there is limited storage capacity between these stations. Given the physical hydraulic constraints of the water delivery and storage structures, the operation of all plants and associated structures must be integrated to ensure control over water elevations and flow can be maintained within the regulatory limits. In order to maintain sufficient control to comply with these regulatory limits, Sir Adam Beck PGS operation cannot physically occur in isolation of Sir Adam Beck I and Sir Adam Beck II in a market that operates on five minute economic dispatch instructions.**[106]

The PWU submits that if the Board is to consider a change in rate structure for OPG's hydroelectric payment amounts, it ought to do so in a proceeding on the rate structures of OPG's payment amounts rather than in a consultation on IRM options.

9.1.3 Option H3. Availability and EFOR Incentives

PA's Option H3 involves the establishment of availability and Equivalent Forced Outage Rate ("EFOR") targets for individual stations or for the portfolio of stations.

With respect to the target levels, PA proposes targets based on recent experience in years in which there were no extraordinary events so that the availability and EFOR targets reflect normal conditions and OPG is not rewarded for performance that is improved over a relatively poor performing year.

The PWU submits that such an IRM must include appropriate quality performance standards and incentives to ensure that safety and environmental performance is not compromised in pursuit of the economic incentives associated with the availability

[106] OEB. EB-2007-0905. Prefiled Evidence. Filed: 2007-11-30. Exhibit I1, Tab 1, Schedule 1. Pages 4-5 of 17.

and EFOR targets. In the PWU's view, the quality performance targets should be based on the measures and targets that OPG uses in its Hydro Generation Business Plan. Doing so provides for realistic targets and incentives, and facilitates the implementation of quality performance regulation.

With respect to the incentives for quality performance (i.e. rewards and penalties), the same guiding principles set forth for the nuclear facilities are applicable to the hydroelectric facilities. As such, the Board should avoid the establishment of incentive programs featuring sharp thresholds between rewards and penalties that may divert attention from public and staff safety and safe plant operation. This would require the adoption of a reasonably broad null zone of acceptable performance in which no rewards or penalty would be imposed. The Board should also avoid the use of short-term measurements that tend to create conflict between economic and safety goals. Financial considerations, as earlier outlined in our comments with respect to the IRM for OPG's nuclear assets, should be taken into account in designing an IRM to be applied to OPG's hydroelectric assets. If OPG faces unrealistic high targets and sharp incentives, it will probably earn a lower rate of return. This results in a negative assessment from the financial market with possible increases in borrowing costs which in turn result in higher payment amounts for OPG's prescribed facilities.

9.1.4 Option H4. Incentives to Maximize "Other Revenues"

PA's Option H4 proposes incentives to maximize Other Revenues by reviewing the appropriateness and current structure of existing variance accounts, specifically for those that are related 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.

The PWU submits that the review of the structure of the existing variance accounts should take place in the proceeding on OPG's next payment amounts application consistent with the Board's current practice of reviewing OPG's variance accounts. However, there is no doubt that any IR plan contemplated for OPG must take into account the structure and disposition of the variance accounts.

With regard to ancillary revenues PA indicates that 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. The PWU recommends that OPG address in its next application the recommendations made by PA with respect to the inclusion of incentives to maximize revenues related to the ancillary services that OPG delivers to the IESO so that the Board may understand the impact of H4's incentives.

9.1.5 Option H5. Price Cap Approach

In PA's option H5 OPG's payment amounts for its hydroelectric prescribed facilities would be based on a maximum amount adjusted by inflation and an X-factor for which special studies would be required. According to PA given the capital-intensive nature of OPG's hydroelectric facilities and the limited review of their OM&A costs in the OPG payment amount proceedings, the prospect for significant cost reduction may be limited. Given the challenges in developing a price cap, PA suggests that it may be adequate to apply the same inflation index that would be applied in the Nuclear price cap, assuming that index is a broad Canadian economic index, and a modest productivity offset that would be based on judgment. H5 includes an earnings sharing mechanism to accommodate fluctuation in capital costs. PA also notes the likelihood of the adoption of an electricity market component that would see a sharing mechanism applying to both the price cap as well as the electricity market impact.

Similar to price cap options for OPG's nuclear assets, H5 lacks quality performance requirements. The PWU repeats its submission that a sound IRM requires robust quality performance regulation as a backstop to quality performance degradation (e.g. safety and environmental performance).

In the PWU's view, the use of a broad-based economic indicator, the determination of a productivity offset based on judgment and the lack of quality performance metrics and incentives, precludes H5 as a reasonable IRM option. Such an approach lacks transparency of the economic incentives and unintended risks and undesirable outcomes. The Board should therefore refrain from adopting Option H5.

9.1.6 Option H6. O&M Efficiency Incentive

PA's Option H6 covers an O&M Efficiency Incentive. According to PA, this option is an alternative to the price cap approach. The PWU does not support H6. As PA notes, focusing only on O&M costs ignores the tradeoff between capital investments and O&M costs that impact many investment decisions and can result in unintended perverse outcomes (e.g. higher costs, intergenerational inequity, penalty for improved total cost efficiency). H6 lacks quality performance regulation and the perverse outcomes could therefore come with quality performance deterioration.

The experience of the 3rd Generation IRM for electricity distributors is illustrative of the outcome of including any incentive based only on O&M costs in an IRM framework. As noted in our review of 3rd Generation IRM for the Ontario electricity distributors, the unintended impact of O&M benchmarking has been faster growth in rate base.

PA does not propose the basis upon which OPG's O&M costs would be adjusted over the IRM term. However, regardless of the adjustment mechanism used, IR for O&M only is flawed. H6 therefore is an unacceptable IR approach.

9.2 London Economics IRM Options for OPG's Prescribed Hydroelectric Facilities

London Economics reviewed the six options proposed in the PA report. London Economics also proposed Option H7 as a variation on a price cap mechanism (i.e. PA's Option H5), with a price trajectory over the IRM term that is based on an embedded productivity target over the revenue requirement (i.e. Building Block approach).

London Economics assessed PA's options and found that H7 would provide for better rate stability by accommodating capital expenditures over time.

The PWU agrees with London Economics that H7 is superior to H5 since it is more pragmatic with respect to the concerns for under-investment in the hydroelectric assets for the sustainment of asset conditions over the long term.

The PWU also agrees with London Economics that OPG's Business Plan is a reasonable starting point. The PWU believes OPG's Business Plan is the proper baseline for OPG's future operations and the establishment of OPG's productivity targets.

PA and London Economics agree that productivity studies for hydroelectric generation would be challenging. As noted by OPG, OPG's peers to be used for comparisons are unregulated and data sharing is a sensitive topic. Under these circumstances, the determination of productivity targets would be based on judgement. From this perspective H7 is not a superior option to H5. Under both options there would be a lack of clarity in determining the productivity offset; hence, the incentives would not be transparent and both options would risk unintended and undesirable outcomes.

Similar to PA's proposed H5 option, London Economics' H7 option lacks quality performance regulation. As the PWU noted earlier in this submission an IRM must include appropriate quality performance standards and incentives to ensure that environmental and safety performance is not compromised in pursuit of productivity gains.

In its presentation at the stakeholder meeting, OPG proposed to file an application in 2013 for determining the payment amount for its prescribed hydroelectric facilities for 2014 and 2015. OPG expects to file an application to implement an IRM for the hydroelectric payment amounts of prescribed hydroelectric facilities in 2016.

As London Economics pointed out at the stakeholder meeting, IR should be applied in a steady state environment i.e. where the regulated utility has matured and is facing steady state operations consistent with a long run path. In the consultation presentation, London Economics also noted that RH Saunders hydroelectric facility will undergo life extension in the next 10 years. The PWU submits that while OPG's proposed timeline for implementing IRM in 2016 is reasonable, the RH Saunders life extension project will need to be addressed through a Building Block approach as it would not be a part of OPG's steady-state operations.

9.3 PWU Conclusion on IR for OPG Hydroelectric

If the Board is determined to implement IR for OPG Hydroelectric, the PWU submits that the implementation from 2016 of an IRM for OPG's prescribed hydroelectric facilities might be accomplished as follows:

- In its 2014-2015 COS payment amounts application OPG files:
    - A 5-year business plan (2014-2018), including forecast annual regulated hydroelectric budgets (adjusted for inflation) and performance targets for each year that incorporate efficiency gains;
    - Estimates of the annual efficiency gains incorporated in the business plan;
    - A proposal on IR quality performance metrics (e.g. employee safety; environmental) including targets and incentives; and
- Initial payment amounts for the IR term, $P_{0,}$ are set in the COS review;
- Annual payment amount IR adjustments are based on the efficiency gains implicit in OPG's business plan and the change in the Board's cost of capital provisions;
- Performance targets and efficiency gains are embedded in the forecast of future operating and capital costs that are used to forecast the revenue requirement and the rate schedule for each year within the IR plan (i.e. Building Block approach).
- Quality performance metrics, targets and incentives are proposed by OPG based on its business plan and performance is reported annually;
- The IR framework includes an earnings sharing mechanism;
- The IR framework includes a Z factor; and,
- The IR Building Block framework provides for variance accounts to accommodate variances between forecast and actual amounts related to economic and market uncertainties.

Given the importance of the safety and environmental performance in the operation of hydroelectric assets, the PWU is of the view that these two performance areas must be an essential part of any IR approach.

The PWU submits that defining safety and environmental performance targets and incentives requires expertise on these performance areas; therefore, this task should be left to OPG. To ensure that the targets are realistic and that they are appropriate for OPG, the PWU recommends that the metrics and the level of targets should be based on and supported by OPG's business plan.

10 CONCLUSION

There are significant challenges and obstacles to the development of an IR approach for OPG that must be recognized and assessed in considering the risks and practicality of implementing IR for OPG. Implementing a simplistic transitional IR approach as a first step with the intent of evolving the framework to address the challenges is not acceptable. The incentives implicit in such an approach would not be transparent and can result in unintended perverse outcomes that compromise the sustainability of the facilities and service value (e.g. safety). This would be counter to the Board's stated objectives for IR of "sustainable gains in efficiency, appropriate quality of service and an attractive investment environment".

Any outcome that involves the compromise to safety in the case of OPG's nuclear facilities can be dire and the OEB should heed the concerns raised by the U.S. NRC on State regulators' IR involving nuclear power plants. The PWU submits that the OEB should involve the CNSC in any discussions on IR for OPG's nuclear facilities.

There are significant challenges and obstacles to the implementation of an IR TFP cap mechanism for OPG related to uncertainties that OPG is facing. Incentives for cost and quality performance can be powerful and a comprehensive understanding of how an IR plan can meet the desired objectives while addressing the challenges and obstacles is essential. There is an apparent absence of precedents of IR plans for generation-only utilities that might help evaluate the implications of IR options for

OPG. In the absence of such insight, there is a serious risk that the incentives may result in inadvertent deterioration of quality performance and compromise the sustainability of the regulated assets that OPG has stewardship over on behalf of the people of Ontario. With OPG's regulated assets providing a significant portion of Ontario's low cost baseload generation, a reduction in the production from these assets will result in higher electricity prices if higher-priced generation supply is required to make up for the lost production. This outcome would be detrimental for electricity customers and the economy, and is not in the public interest.

Addressing the challenges and obstacles precludes the implementation of an IR TFP approach for OPG and would require a complex IR framework. It is not acceptable, even as a starting point, to settle for a simplistic IR framework that arises from the lack of real world precedents of IR for generation-only utilities, the limits of the Board's own IR experience, and the Board's limited familiarity with the costs and safety performance of OPG's complex operations. Doing so exposes OPG and consumers to the risks of unanticipated perverse outcomes including nuclear safety concerns. Given the improbability that these challenges will be overcome and the potential risk to safety performance it would be imprudent to compel OPG to embark on a broad IR plan in 2015, if ever.

OPG's business is highly complex and as noted in the Board's decision on OPG's 2011-2012 payment amounts, "[a]spects of OPG's generation businesses must be suitably studied and accommodated in a plan".[107] The Board has only reviewed two OPG payment amounts applications and does not have the requisite information base to allow it to develop a robust IR framework. Therefore, while the PWU does not view IR as the appropriate regulatory approach for OPG, if the Board is determined to implement IR for OPG, the cost and quality performance targets and incentives should be developed by OPG based on its business plan in order to

[107] OEB. EB-2010-0008. Decision with Reasons. Ontario Power Generation Inc. Payment Amounts for Prescribed Facilities for 2011 and 2012. March 10, 2011. Page 154.

mitigate the risk of negative outcomes and to provide for a reasonable and implementable plan.

All of which is respectively submitted.