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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: Renewed Regulatory Framework for Electricity Transmitters and Distributors – Defining and Measuring Performance of Distributors and Transmitters (EB-2010-0379)

The Power Workers' Union ("PWU") represents a large portion of the employees working in Ontario's electricity industry. Attached please find a list of PWU employers.

The PWU is committed to participating in regulatory consultations and proceedings to contribute to the development of regulatory direction and policy that ensures ongoing service quality, reliability and safety at a reasonable price for Ontario customers. To this end, please find the PWU's comments on the RRFE's initiative on Defining and Measuring Performance of Distributors and Transmitters, EB-2010-0379. Expert comment and analysis by Dr. Francis Cronin is provided in Attachment A: *Assessing Distribution Incentives and Performance: 2000-2012*.

We hope you will find the PWU's comments useful.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

Richard P. Stephenson
RPS:jr
encl.

cc: Judy Kwik
John Sprackett

List of PWU Employers

Algoma Power
AMEC Nuclear Safety Solutions
Atomic Energy of Canada Limited (Chalk River Laboratories)
BPC District Energy Investments Limited Partnership
Brant County Power Incorporated
Brighton Beach Power Limited
Brookfield Power – Mississagi Power Trust
Bruce Power Inc.
Atlantic Power - Calstock Power Plant
Atlantic Power - Kapuskasing Power Plant
Atlantic Power - Nipigon Power Plant
Atlantic Power - Tunis Power Plant
Coor Nuclear Services
Corporation of the City of Dryden – Dryden Municipal Telephone
Corporation of the County of Brant, The
Coulter Water Meter Service Inc.
CRU Solutions Inc.
Ecaliber (Canada)
Erie Thames Services and Powerlines
ES Fox
Great Lakes Power Limited
Grimsby Power Incorporated
Halton Hills Hydro Inc.
Hydro One Inc.
Independent Electricity System Operator
Inergi LP
Innisfil Hydro Distribution Systems Limited
Kenora Hydro Electric Corporation Ltd.
Kincardine Cable TV Ltd.
Kinectrics Inc.
Kitchener-Wilmot Hydro Inc.
Lake Superior Power Inc. (A Brookfield Company)
London Hydro Corporation
Middlesex Power Distribution Corporation
Milton Hydro Distribution Inc.
New Horizon System Solutions
Newmarket Hydro Ltd.
Norfolk Power Distribution Inc.
Nuclear Waste Management Organization
Ontario Power Generation Inc.
Orangeville Hydro Limited
Portlands Energy Centre
PowerStream
PUC Services
Sioux Lookout Hydro Inc.
Sodexho Canada Ltd.
TransAlta Generation Partnership O.H.S.C.
Vertex Customer Management (Canada) Limited
Whitby Hydro Energy Services Corporation

EB-2010-0379

Defining and Measuring Performance of Distributors and Transmitters

Submission of the Power Workers' Union

1 INTRODUCTION

On December 17, 2010 the Ontario Energy Board ("OEB" or "Board") initiated a consultation on the development of a Renewed Regulatory Framework for Electricity transmitters and distributors ("RRFE"). The Board's November 8, 2011 Notice states that the Board's objective for the RRFE is to "encourage and facilitate greater efficiency through a focus on performance-based outcomes and a disciplined, long-term approach to investment planning" to help ensure the reliable and cost-effective delivery of electricity to Ontario consumers.

According to the attachment to the Board's March 20, 2012 letter to stakeholders, the RRFE consultation will lead to the development of Board policies for a RRFE which will:

- **Establish performance outcomes that reflect consumers' expectations and encourage enhanced utility productivity;**
- **Provide for efficiently planned investments in grid sustainment, expansion and modernization that consider pace and prioritization;**
- **Align rate setting cycle and investment planning horizon and provide for efficient recovery of costs;**
- **Increase efficiency in the regulatory process through greater focus on outcomes; and**
- **Consider the total bill impact on consumers.**

The consultation consists of five initiatives, one of which is on *Defining and Measuring the Performance of Electricity Transmitters and Distributors (EB-2010-0379)* ("Performance"). In its October 27, 2010 announcement the Board states that the Performance initiative is to consider ways of setting efficiency standards and providing appropriate incentives.

On November 8, 2011, the OEB released a staff discussion paper entitled *Defining and Measuring the Performance of Electricity Transmitters and Distributors (EB-2010-0379)* ("Performance Discussion Paper") that solicits comments of alternative ways of setting standards for performance and providing appropriate incentives to transmitters and distributors. Along with the staff discussion paper, the Board issued an April, 2011 supporting paper prepared by Dr. Lawrence Kaufman of Pacific Economics Group Research ("PEG") entitled *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, which provides a summary of research and expert advice.

2 POWER WORKERS' UNION'S VISION AND CONTEXT FOR THE RRFE

The Power Workers' Union ("PWU") appreciates the opportunity provided by the Board for stakeholders to share their views on issues related to the RRFE. The PWU's views on the RRFE stem from its energy policy statement:

> **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.**

The PWU's vision for a sustainable and long-term regulatory regime for the electricity utilities is one that focuses on customer value and establishes appropriate and transparent incentives based on Ontario utility data to achieve performance levels that align with customer expectations.

To achieve this vision it is necessary to recognize customer value as the key input to the regulatory framework. This key input would be obtained through robust customer Willingness to Pay ("WTP") surveys that will establish the utilities' service quality (i.e.

customer service and system reliability) standards and provide the context for the utilities' network investment planning and the regulatory framework.

The OEB and utilities will need to educate customers to build an understanding of the value and cost of electricity services and the impact of Government energy policy on them. Customer WTP surveys will form the basis for utilities' asset management and investment planning thus incorporating customer value into the utilities' determination of service quality standards and cost. Regulatory incentives and benchmarking based on empirical analysis of Ontario utility data would be used to achieve service quality and total cost performance. Standards for asset management best practices would ensure system sustainability while mitigating time and cost of regulatory review processes. To enhance the sustainability of the regulatory framework issues that utilities are or will face (e.g. aging assets, workforce renewal) should be addressed expeditiously. The framework needs to recognize that customers are unlikely more able to accommodate rate increases in the future than they are today and that postponing maintenance and capital investments to mitigate rate increases today compromises future service quality and results in higher future rate increases. Therefore bill impact mitigation will be limited to *ex-post* mitigation.

The PWU addresses *Defining and Measuring Performance of Distributors and Transmitters* in the context of its vision and context for the RRFE set out above. In addition the PWU provides comments on issues set out in the April 5, 2012 correspondence from the Board as well as questions posed in the Performance Discussion Paper.

3 OEB's IR FRAMEWORK FOR ELECTRICITY DISTRIBUTORS

The OEB's Incentive Regulation ("IR") framework has yet to evolve into a comprehensive and robust framework. The Board's RRFE initiative is an opportunity for the Board to establish such a framework based on lessons learned since it took on regulatory authority over the electricity distributors. The Board has required broad reporting of distributor information since 2000. The Board also has in its possession a substantial pre-2000 information base that the Board either obtained directly from the distributors or that was collected by the former administrative regulator of the distributors, Ontario Hydro. In filing audited financial and operating statements with Ontario Hydro, the distributors followed regulatory accounting procedures based on Canadian Generally Accepted Accounting Principles as the Board required before the transition to International Financial Reporting Standards. The Board should capitalize on this critical information base and conduct research and analyses on Ontario distributors' total cost and service quality performance to form a transparent and informed basis for the RRFE. The substantial distributor information base in the Board's possession precludes citing a lack of data and/or experience as a reason for delaying the implementation of a comprehensive RRFE. The Board's ability to do so is an advantage that it has that will contribute to the fairness and sustainability of the RRFE and allow the Board to meet the objectives it has set out for the RRFE

Below is an examination of the Board's IR frameworks and their key shortcomings that need to be addressed for the RRFE. Technical issues and other considerations that the Board needs to consider in its IRM approach are expanded on in Sections 6 and 7.

3.1 First Generation PBR

The OEB implemented First Generation PBR in taking on its regulatory responsibility of the Ontario electricity distributors in 2000. First Generation PBR's price cap was aborted with the Government's introduction of the *Electricity Pricing, Conservation and Supply Act* in December 2002 which among other measures froze Ontario's transmission and distribution rates until May 1, 2006. However, all reporting requirements introduced with First Generation PBR continued, including PBR related O&M, capital and service quality information.

First Generation PBR's price cap was based on the Ontario distribution industry's Input Price Index ("IPI") adjusted for Total Factor Productivity ("TFP") based on Ontario distributors' data collected by the Board and Ontario Hydro going back to the early 1970s for capital and early 1980's for O&M.

First Generation PBR was characterized as a transition plan that was to have a mid-term review to help design a second generation PBR.[1] It included minimum service quality standards but not incentives for service quality performance. 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 in the first year and service quality performance data became 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 experience with the application of the PBR plan for the first year and appropriate service quality performance data becomes available.[2]**

3.2 2nd Generation IRM

The objective of 2nd Generation IRM, developed in 2006, was to provide regulatory certainty to distributors during the rate plan as it carried out several rate-related studies. The Board described 2nd Generation IR as a "transitional mechanism, and not an end-state itself" which 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":[3]

> **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.[4]**

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[1] Ontario Energy Board. RP-1999-0034. Decision with Reasons.
[2] Ontario Energy Board. RP-1999-0034. Decision with Reasons. Page 53, Paragraph 5.0.27.
[3] Ontario Energy Board. EB-2006-0089. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Page 23.
[4] Ontario Energy Board. EB-2006-0089. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Pages 31-32.

Critically, however, 2nd Generation IRM's formulaic rate adjustment took the distributors away from First Generation IRM's basis in Ontario LDCs' historical cost and the incentives and price signals from the Ontario distribution industry IPI and instead used the macroeconomic index, the Canada Gross Domestic Product Implicit Price Index (GDP-IPI) for final domestic demand as the price escalator. Further, it did so by basing a productivity factor of 1% on a survey of other jurisdictions and suggestions by distributors and consumer groups rather than TFP analysis on Ontario distributors' empirical data.

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 stakeholders' concerns and committed to resume its service quality regulation ("SQR") review to refine its SQR for electricity distributors.[5] Unfortunately, it was not until 2008 that the Board undertook even the simplest analytical review of service quality. Most notably, compliance with the 2000 standards was not addressed.

The 2nd Generation IRM's formulaic rate adjustment, that was driven mainly by the stated need for simplicity and transparency superseded consideration of the cost pressures, acknowledged by many LDCs, and failed to consider the incentives that the formulaic adjustment might impart on the distributors.

3.3 3rd Generation IRM

For 3rd Generation IRM the Board remained with a GDP-based macroeconomic inflation index. Distributors do not need to deal with a comprehensive cost budget as 3rd Generation IR introduced a completely new wrinkle: partial cost benchmarking.

[5] EB-2006-0089. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Pages 39-40.

Further, there was a change in the Board's perception of the distributor's pre-2002 capital data between First Generation PBR and 3rd Generation IR. As a result information from a US utility database was used to derive the TFP for 3rd Generation IR instead of a TFP based on Ontario distributors' data. The productivity benchmark inherent in 3rd Generation's TFP therefore is not based on the Ontario distributors' circumstances. These major shortcomings of 3rd Generation IRM are related to the Board's decision not to use the distributor's pre-2002 capital information. The Board provided no evidence in support of its decision not to use the pre-2002 data in developing 3rd Generation IRM.

In 2006, the Board initiated a consultation on the comparison of distribution cost (EB-2006-0268) for the purpose of assisting it in the 2008-2010 rebasing proceedings and in the development of 3rd Generation IRM. The cost comparison was based on partial cost: O&M only.

As in the earlier plans, 3rd Generation IRM did not include incentives for service quality performance. In a scoping paper on 3rd Generation IRM, Board staff noted that service quality regulation was expected to be developed separately and in parallel with the consultation on 3rd Generation IRM.[6] To date the Board has not developed service quality incentives.

4 OEB's RRFE and Ofgem's RIIO

The PWU agrees with Board staff's suggestion in the Performance Discussion Paper that the RRFE consultation can be informed by Ofgem's RPI-X@20 consultation.[7] While the Performance Discussion Paper emphasizes the similarities in objectives, the PWU would also emphasize the similarities in the challenges that the OEB needs to address and those that Ofgem is addressing in its 'Revenue using Incentives to deliver Innovation and Outputs' ("RIIO") model.

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[6] EB-2007-0673. 3rd Generation Incentive Regulation for Electricity Distributors Staff Scoping Paper. August 2, 2007. Page 4.

[7] EB-2010-0379. Ontario Energy Board. Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors. November 8, 2011. Appendix B. Page III.

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 UK energy network sector. As articulated by Ofgem these challenges include: targets for tackling climate change, security of supply, widespread maintenance, and upgrading of aging networks[8]. In addition, Ofgem identified significant uncertainties that the network companies are facing related to: 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' actual costs; and, the possible impact of the economic downturn that will impact load growth, cost of material, financing cost and inflation. Ofgem noted:

> **The existing RPI – X' regulatory framework has served consumers well, delivering lower prices, better quality of service and more than £35bn in network investment since privatisation twenty years ago. But RPI – X was designed for a very different environment to the one we will face in the future. The regulatory framework needs to change to encourage network companies to deliver a sustainable energy sector and provide value for money.[9]**

Ofgem has incorporated SQR based on WTP and line losses in its regulatory framework. However, according to Ofgem, the existing 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. 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."[10] 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

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

[9] Ofgem. Regulating energy networks for the future: RPI-X@20 Recommendations. July 26, 2010. Page 2.

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

while maintaining a safe, secure and affordable system for existing and future consumers".[11]

In addressing these concerns Ofgem reviewed the regulatory tools available for sharing risk associated with the uncertainties. The outcome of RPI-X@20, the RIIO, is 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.[12] Ofgem's Handbook for implementing the RPI-X@20 price control framework describes the model as follows:[13]

> **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 sustainable network regulation, RPI-X@20, builds on close to 20 years of IR experience for the network sector.

Like the RIIO regime, the OEB's RRFE needs to provide for the sustainability of the distributors' systems and operations at levels that customers value in these times of significant and rapid social and economic change. The scope of the OEB's

[11] Ofgem. Regulating energy networks for the future: RPI-X@20 Recommendations: Implementing Sustainable Network Regulation, July 26, 2010. Context.
[12] Ofgem. Regulating Energy Networks for the Future: RPI-X@20. History of Energy Network Regulation. 13b/09. February 27, 2009. Page 45.
[13] Ofgem. Promoting Choice and Value for all gas and electricity customers. RIIO. Handbook for Implementing the RIIO Model. October 4, 2010. Page 29.
http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf

regulatory challenges are similar to that of Ofgem's e.g. the *Green Energy Act* targets; maintaining security of supply; widespread maintenance and upgrading of aging networks; and, the high rate of retirement that comes with an aging workforce. A comprehensive approach such as Ofgem's RIIO that recognizes these challenges needs to be the start point for the OEB's RRFE. This would include, as in the case of the RIIO, incentives for line losses.

5 LINK BETWEEN COST AND SERVICE QUALITY PERFORMANCE

IR should incent cost efficient investment levels that allow for system sustainability at service quality performance standards that customers value and expect. This requires acknowledging the direct link between cost and service quality performance in the development of the RRFE. Ultimately, investments deferred in response to IR focused on short-term cost performance incentives will result in higher future costs to address deferred investments and future service reliability levels. There is the need for the Board to analyse the impact of its cost regulation on the distributors' asset condition management that impacts the distributors' ability to maintain/improve future service quality performance.

In a submission filed by the PWU in the first phase of the Board's consultation on service reliability standards (EB-2010-0249) Dr. Cronin notes that while Board staff's 2008 analysis indicated that reliability varied widely among distributors in the Board's peer groups, these differences were not reflected in 3rd Generation IRM's productivity factors which were set in isolation of reliability performance. In Dr. Cronin's view this raises the following questions:

- **When we look at the Board's peer groups, is it possible that some LDCs with degraded reliability had lower O&M costs compared with its peers? Could these LDCs with lower reliability and lower O&M costs have been rewarded by the Board with lower X factors in 3rd Generation IR?**
- **Is it possible that some of the LDCs that were judged to be less efficient by the Board based on O&M could have had lower customer interruption costs based on their higher reliability?**
- **Finally, is it possible that some of the LDCs that were judged to be less efficient by the Board which had lower customer interruption costs (based on their higher reliability) could have been operating with a *more socially optimal budget* since their inclusive total costs including customer interruption costs were lower than the inclusive costs of LDCs with lower**

O&M costs, lower reliability, higher customer interruption costs, and higher inclusive total costs?

If these observations are in fact true, what message is the Board's cost comparison and 3rd Generation IR frameworks sending to the LDCs? Will those LDCs with higher reliability but higher O&M cut costs and degrade service reliability?[14]

The Performance Discussion Paper recognizes that an effective regulatory framework must provide for prudent capital investments in order to maintain an appropriate level of service quality:

An effective framework encourages transmitters/distributors to implement efficiencies and allocates the benefits from greater efficiency between the transmitter/distributor/shareholder and ratepayers in an appropriate manner. An effective framework also provides for prudent capital investment as required to ensure necessary infrastructure development and to maintain an appropriate level of reliability and quality of service.[15]

The PWU agrees whole heartedly with the above statement but notes that it should not be assumed that all distributors' service quality performance are currently at the levels that meet customer expectations.

In the PWU's view ensuring that customer expectations are met compels the Board to pursue research and analyses on the distributors' data it has in its possession to form a sound empirical basis for a RRFE that addresses customer value and expectation determined through WTP and recognizes the direct link between the distributors' cost and service quality performance.

[14] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 4. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[15] Board Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors (EB-2010-0379). Page 28. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Staff_Discussion_Paper_20111108.pdf

6 COST PERFORMANCE

6.1 Ontario Distribution Industry IPI

The Ontario distribution industry IPI properly reflects changes in the distributors' input prices and therefore provides the distributors with the appropriate benchmark for their input prices. The 2000 version of the OEB's Electricity Distribution Rate Handbook[16] ("Rate Handbook") describes the efficiency incentive implicit in the distribution industry IPI as follows:

> **The purpose of the IPI adjustment is to allow each utility to pass through changes in the prices of the inputs it purchases, at the rate determined by the *typical* utility's experience with input prices during the previous year. An utility whose own input prices rose less than the input prices of the typical utility would increase its earnings if it chose to adjust its own price cap by the full amount allowed by the Board. On the other hand, an utility whose own input prices rose more than those of the typical utility would experience a reduction in earnings due to the allowed adjustment.**
>
> **This IPI[2] is specific to the electricity distribution utilities in Ontario. The index comprehensively measures changes in the prices of inputs employed by the utilities including capital, labour and materials. The IPI is the index formed by the addition of subindices of input prices weighted by the cost share of each input.**

In its decision on 2nd Generation IRM the Board stated that although the GDP-IPI is a macroeconomic measure, it is published by a trusted source, is readily available, and is likely more easily understood by the public than an industry-specific measure would be.[17] However, the Board recognized that the IPI approach used in first generation PBR tracks industry input price fluctuations better than an economy-wide measure and may better mitigate significant gains and losses related to the failure of a macroeconomic index to track industry input price inflation:

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[16] Ontario Energy Board. Electricity Distribution Rate Handbook. 2000. http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/First+Generation+PBR+Distribution+Rate+Handbook

[17] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive regulation for Ontario's Electricity Distributors. December 20, 2006. Page 28. http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0088/report_of_the_board_201206.pdf

> **The Board recognizes that an IPI would track industry input price fluctuations better than an economy-wide measure. It may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. However, the Board observes that the implementation of the IPI methodology that was used in 1st Generation IR with recent data produces a very volatile index, as shown in the illustrative example presented in the Discussion Paper. Such volatility could be harmful to both ratepayers and distributor shareholders, if reflected in rates. The Board believes that further research is required on the methodological approach to address such volatility and to ensure that the chosen sub indices appropriately track the inflation faced by the industry.**[18]

Further, the Board acknowledged that electricity distribution is capital intensive and that changes in distributors' cost of funds can differ from that of an economy-wide measure. In making its decision, the Board expressed the view that the GDP-IPI approach is less controversial and easier to implement.

> **The Board is of the view that a macroeconomic index is easier to implement for 3rd Generation IR: only one index needs to be obtained and the only calculation necessary will be the annual change in the index. In addition, the macroeconomic index that will be used, GDP IPI-FDD, tends to grow at a relatively stable rate over time and it is familiar to Board staff and stakeholders, since it is currently being used in 2nd Generation IR and in both gas IR plans.**

While cost performance incentives based on appropriate empirical data forms the basis for predictable outcomes, compromise in the incentive mechanism results in flawed incentive with unpredictable results. Therefore, the PWU recommends that the Board use the IPI approach in the RRFE. With regard to any volatility in the IPI, the PWU submits that the same mechanisms to smoothen volatility available in multi-year cost of service rates can be used to smooth any volatility related to the IPI (i.e. deferral and/or variance accounts) and should be used to do so rather than compromise the cost performance incentive with the use of an inappropriate macro-economic index.

[18] EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 10-11.

6.2 Ontario Distributors' TFP and Total Cost Benchmarking

The 2000 Rate Handbook describes the TFP approach used in First Generation PBR and how the TFP serves as a productivity benchmark as follows:

> **Due to biases in measuring productivity change based on any one input (e.g., labour) or even a subset of inputs (e.g., labour and materials), a measure of the utilities' productivity has been adopted that is based on a comprehensive assessment of the distributors' inputs. This measure is total factor productivity ("TFP") and is designed to reflect the change in output that cannot be accounted for after taking account of changes in use across all inputs.**
>
> **Thus, while changes in TFP may be due to a number of factors, the intended purpose is to establish broad TFP benchmarks that reflect the experience of Ontario utilities.**

The Board's decision not to use the distributors' pre-2002 information in 3rd Generation IRM limited its ability to set the TFP based on Ontario data and to set productivity stretch factors based on peer groups established through total cost benchmarking. In the PWU's view, unless there was gross negligence in the distributors' filings of pre-2002 data, the Ontario distributors' data would have been the appropriate information base to use in establishing productivity for Ontario's distributors compared to the information used from a U.S. data base. Given the distributor's use of regulatory accounting procedures, as well as the audit requirement of the financial and operating statements, it is unlikely that there would have been gross negligence in filing the distributors' historic information.

Consideration of a utility's capital costs is a significant issue in IR. In a 2005 report on the theory and practice of IR for network companies, P. L. Joskow notes that the lack of proper accounting for capital costs 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 has been the case in many**

> **developing countries following guidance from World Bank regulatory gurus, can lead to serious performance problems.**[19]

In Attachment A Dr. Cronin estimates that the distributors' average TFP growth during the 2000-2005 price freeze was about 1.86 per year on an un-weighted basis and 0.57 on a customer weighted basis. This was similar to the TFP growth estimated for the mid-1990's voluntary price freeze. On the other hand, average TFP growth for distributors under IR in 2006-2010, was notably lower - estimated at -0.24 per year on an un-weighted basis and -0.40 on a customer weighted basis. With regard to the decline in TFP growth Dr. Cronin makes note of the factors that would impact TFP growth rates:

> **Any factor affecting either the output or the inputs of LDCs would impact TFP growth rates. On the output side these include both economic (e.g., cycle) and demographic (e.g., population). On the input side these include such factors as institutional (e.g., hiring and training replacement workers for retirees), technical (e.g., capital additions for network replacement)[20], and mandates (i.e., required expenditures that LDCs are obligated to undertake).**

With regard to the regulatory impacts on the observed decline in TFP growth rate Dr. Cronin identifies the following design choices as impacting performance:

- **systemic incentive failures;**
- **dis-incent permanent productivity improvements with a 3-year On, 1-year Off schedule: in fact, rate increases in the COS rebasing year average about 13 percent;**
- **constant changes to regulatory framework and governance;**
- **incent some LDCs to make non optimal changes to their capital – labour mix;**
- **add unnecessary, imprudent "capital costs", further exacerbating allocative inefficiency and increasing future rates for customers.**

Further, Dr. Cronin notes:

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[19] 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.

[20] Of course, the impact of cost shifting from O&M into capital additions would need to be sorted out as well. Below, we estimate the extent of the cost shifting.

Adding in "Green" considerations, losses, or customer reliability valuations would make the decline in total, inclusive performance worse.

- **design profoundly environmentally unfriendly (i.e., Non-green)**
- **design incents degraded losses as standards for losses performance were lacking[21]**
- **design incents degraded losses as costs spent on O&M to improve losses are penalized by OEB**
- **design requires larger supplies of power, network resources, and generation to compensate for the degraded system losses**
- **design incents LDCs to cut prudent costs and degrade reliability**
- **design incents some LDCs operating at or close to a socially optimal position to degrade O&M and reliability, and to cause valuations for customer interruption losses to increase.**

The use of partial cost benchmarking is inherently flawed and does not provide an appropriate foundation for IR. Benchmarking based mainly on O&M costs rather than total cost in establishing productivity stretch factors for the distributors creates perverse incentives, inaccurate efficiency rankings, and can easily be addressed by the regulated utilities through accounting adjustments.

According to Dr. Cronin, the main focus on O&M in 3rd Generation IRM penalizes distributors that capitalize small amounts of labour or that have production processes that rely more on labour than on capital.[22] He found the Ontario distributors' capital intensity to be substantial ranging from 40 per cent to 60 per cent of the costs. The Board's cost efficiency benchmarking approach therefore misses a significant portion of the distributors' costs. Further Dr. Cronin notes the lack of consideration of service quality performance in the 3rd Generation IRM benchmarking approach.

Dr. Cronin's comments and analyses in Attachment A, *Assessing Distribution Incentives and Performance: 2000-2012*, provides evidence on such outcomes for Ontario electricity distributors:

[21] This was quite unfortunate as the utilities had made sizeable improvements in line losses over the 1988 to 1997 period, saving customers hundreds of millions of dollars. Unfortunately, these prior savings have now been wiped out.

[22] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 1. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

- A massive shift of Labour from O&M to Capital between 2001 and 2010 that resulted in an average increase in labour capitalization of 228 per cent among the Ontario's distributors. The implications include:
  - Each dollar of capital additions puts in less hardware and more labour or overhead and will require higher amounts of capital additions than in the past to remedy degradation of network reliability; and,
  - Rate bases grow faster with the significant shift from O&M costs to capital costs and result in higher rates.
- The efficiency rankings associated with O&M costs are random, biased and bear no relationship to a distributor's total costs. The implication is:
  - The Board has ranked LDCs that are actually among the most efficient based on total cost as inefficient based on O&M benchmarking; and,
  - The Board rewards inefficient LDCs that are incorrectly ranked as efficient based on O&M costs while penalizing utilities that are in fact efficient based on total cost ranking.

Given the link between cost and service quality performance it is imperative that service reliability performance be factored into cost benchmarking. The Board's current approach creates inappropriate rankings, incentives, behaviour, and rewards/penalties consistent with the inappropriate foundation of the regulatory framework; and, results in inequitable treatment of the utilities and their customers. Incentives are a powerful tool and have been shown empirically to dramatically affect utility performance: compromised incentives will work to produce troubling outcomes. Therefore the PWU identifies the need to account for differences in service quality performance amongst the distributors in any cost benchmarking that will be undertaken in the RRFE.

The availability of a reasonable capital data time series that correctly captures the investment pattern and value of the distribution assets with typically long life cycles is essential in analysing the distributors' cost performance. Absent the ability to assess the distributors' cost efficiency over time, the potential impact of cost efficiency incentives is not transparent. The development of the RRFE is the opportunity for the

Board to get it right. "Getting it right" involves making use of all the information that the Board has in its possession, including the pre-2002 data, to conduct research and analyses to assess the distributors' cost efficiency and develop transparent cost performance incentives that can ensure the sustainability of service reliability performance that meets customers' expectations in a cost efficient manner.

6.3 Replacing Aging Assets

In the consultation on 2nd Generation IRM utilities raised the issue of aging infrastructure and the need for increased investment to maintain service quality at levels that are beyond those supportable by existing rates. The utilities proposed that the IR framework accommodate incremental capital investments related to growing capital programs over the term of the plan. 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's 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 monitoring requirements of 2nd Generation IRM because it would require special consideration to be implemented effectively.[23]**

While rebasing of rates to accommodate a growing rate base would be required over the course of the IR term to address the utilities' plight, the Board expected that utilities' need for inordinate capital investments could be accommodated through the rebasing of rates at the start of 2nd Generation IRM.

[23] EB-2006-0089. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Page 37.

In a Board consultation on rate-making associated with distributor consolidation, the distributors again raised the need for policy that allows opportunity for capital investment needs to be addressed as and when they arise.[24] 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.

In the consultation on 3rd Generation IRM Board staff noted that some stakeholders identified the need for approval of a multi-year capital plan:

> **Some participants argued that certainty in relation to capital expenditures beyond the single future test year is needed. It was suggested that the regime could include some form of approval of a multi-year capital plan and not just capital items that may arise in the following year.[25]**

While the Board included a capital module in 3rd Generation IRM,[26] the application of the module has been excessively restrictive. In rejecting Hydro One Network's application for a capital module (EB-2008-0187) the Board indicated in its decision 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.[27]**

In a letter to the OEB dated March 25, 2011 Toronto Hydro ("THESL") articulated the challenges of maintaining system sustainability within the Board's IRM given the need for significant infrastructure investments and workforce renewal:

> **... 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**

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[24] Cover Letter. Report of the Board on Rate-making Associated with Distributor Consolidation Board File No.: EB-2007-0028. July 23, 2007 page 5.
[25] EB-2007-0673. 3rd Generation Incentive Regulation for Electricity Distributors Staff Scoping Paper. August 2, 2007. Page 5.
[26] EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008.
[27] OEB Decision. EB-2008-0187.

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.[28]

In its presentation at the March 28-30, 2012 RRFE consultation meetings, the Distribution Regulation Review Task Force[29] ("Task Force") spoke to the challenges faced by many utilities under the IR framework related to the increased need for capital to fulfill their system safety and reliability obligations. The Task Force looks to the RRFE to address the need for infrastructure investment in a manner that addresses customer expectations while rewarding higher performing utilities.

It is essential for the sustainability of the distribution systems, that the OEB recognize the need for the distributors to replace aging assets as Ofgem has done. In 1990 Ofgem implemented its price control for network utilities using a simple RPI-X (i.e. inflation index minus productivity adjustment) approach. In its consultation process for the price control framework for 2005-2010, 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 would 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.[30] In recognizing the need for the increased capital investments in the 2005-2010 price control period Ofgem included a 48 per cent average increase in allowed capital expenditures over the 5-year price cap term.

The PWU submits that the Board needs to deal effectively with the significant issue of aging assets as Ofgem has done in its 2005-2010 price control period. In doing so the Board should recognize that there are also O&M costs related to the replacement

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[28] Toronto Hydro letter to the OEB, Notice of Filing Intentions for 2012 Distribution Rates, March 25, 2011:http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/278248/view/THESL_response_rebasing%202012%20rates_20110325.PDF

[29] Presentation by Distribution Regulation Review Task Force to OEB on Renewed Regulatory Framework Review. March, 2012. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0377/DRRTF_Stakeholder%20Conference_20120321.pdf

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

of the aging assets. Delays in making the required investments will only continue to exacerbate the challenges of maintaining service quality and increase costs in the long run. The PWU supports providing the utilities with the option of multiple-year capital programs as well as the option of using capital modules. This provides utilities with some flexibility in addressing uncertainty that might be inherent in multi-year capital programs and will minimize the need for a utility to off-ramp the IR plan and file annual cost of service rate applications instead. However, given the critical need to replace aging assets the Board should take on the task of amending the ICM approach to address the issues faced with the current approach.

6.4 Workforce Renewal

The Board needs to recognize the incremental costs related to workforce renewal in the RRFE, including costs for recruiting and training programs and reasonable compensation levels to attract suitably skilled and experienced workers.

According to a 2011 Electricity Sector Council report entitled *Recharging our Workforce, A Strategic Framework For Industry Action*,[31] the Canadian electricity industry is facing and expecting a workforce retirement rate of close to 30 per cent between 2007 and 2012. The current population age demographics that results in the significant challenge of replacing an aging workforce is a well recognized issue that the RRFE needs to consider in its consideration of network investment planning as illustrated by the challenges described below.

It takes three to five 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 perform needed functions safely and efficiently as**

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[31] Recharging our Workforce. A Strategic Framework For Industry Action. Final Report. 2011. http://www.brightfutures.ca/Training/english/report/RechargingOurWorkforce_Report_e.pdf

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.

The Board therefore must recognize the need for the distributors to adequately account for workforce replacement in network investment planning.

6.5 Economic Uncertainty

As noted earlier, in developing RIIO Ofgem recognized 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' actual costs; and, the possible impact of the economic downturn that will impact load growth, cost of material, financing cost and inflation. All of these factors related to the current economic uncertainty that prevails must also be addressed in the RRFE and will require flexibility in the implementation of the RRFE to accommodate the uncertainty and enhance the RRFE's sustainability. Such flexibility should be built into the RRFE by providing options for the utilities.

6.6 Green Energy and Green Economy Act

The *Green Energy and Green Economy Act ("*the GEGEA*")* transforms Ontario's supply mix and requires the utilities to accommodate the addition of a plethora of new non-dispatchable renewable generators. In addition to ensuring that the generators are connected to the system, utilities will need to update their systems with smart grid technology to enable the integration of non-dispatchable renewable generation. The GEGEA also requires substantial Demand-Side Management ("DSM") savings to address supply-side issues that will significantly impact utility throughput. However, given that the distributors' DSM targets were derived through a top-down process that accommodates the Government's provincial DSM target, substantial uncertainty around the achievement of the targets can be expected that challenges the distributors' load forecasts. The RRFE's cost performance expectations will require flexibility to accommodate the GEGEA related challenges.

7 SERVICE QUALITY PERFORMANCE

In this section the PWU highlights the need for the Board to include robust service quality regulation in the RRFE with appropriate incentives for performance that meets customers' valuation of service quality. While the Board has implemented 2nd Generation IRM and 3rd Generation IRM, since 2006 it has lacked effective SQR that would act as a backstop to utilities' cost cuts in pursuit of the Board's IR financial incentives. The OEB's 2000 Electricity Distribution Rate Handbook ("Rate Handbook") stipulated that compliance with the Rate Handbook was a condition of licence:

> **1.3 CONDITION OF LICENCE**
>
> **Compliance with the Rate Handbook is a condition of licence for all electricity utilities in Ontario.**[32]

This provision is consistent with the Board's decision on the 2000 Rate Handbook (RP-1999-0034):

> **In addition to revisions necessary as a result of this Decision, the Rate Handbook may in the future be revised to address Board policies, Codes, and guidelines which affect rates. Compliance with the Rate Handbook will be a condition of licences issued to electricity distributors.**[33]

As such, utilities were required to comply with the minimum service reliability standards as a condition of licence and non-compliance exposed the utilities to the

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[32] Ontario Energy Board. Electricity Distribution Rate Handbook. 2000. Page 1-2. http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/First+Generation+PBR+Distribution+Rate+Handbook

[33] OEB. Decision with Reason. RP-1999-0034. Page 7.

legal ramifications of non-compliance with a licence condition. However, with the absence of this licence condition from the 2006 Rate Handbook, there appears to have been no regulatory consequences for non-compliance and as such no effective regulation of service reliability in place since 2006.

In an article on the theory and application of IR, Paul Joskow speaks to the incentive of pure price cap mechanisms to reduce both costs and quality of service that have increasingly led to the inclusion of service quality performance standards and incentives in IR.

> **…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).**[34]

In the October 29, 2010 submission filed by the PWU in the OEB's consultation on service quality regulation, Dr. Cronin noted IR's incentive to cut OM&A and cited a study prepared by Ter-Martirosyan that examined the effects of IR on electricity distributors' OM&A and service quality performance. Ter-Martirosyan (2003) concludes that strict reliability standards with financial penalties can offset IR's tendency for imprudent cuts in OM&A.

> **The shift to IR can put OM&A costs in conflict with the pursuit of profit during the plan's term. Cost reductions experienced earlier in a plan's term are worth more to a utility than cost reductions achieved in later years. Since capital costs may already be committed, they may not be subject to significant changes in the early years of a plan's term. Therefore the utility could be incented to cut OM&A expenses beyond what is prudent for the reliability of the network.**
>
> **Unjudicious curtailments in OM&A have been shown to significantly lower LDC reliability. Ter-Martirosyan (2003) examined the effects of IR on electricity**

[34] 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 37.

distributors' OM&A and service quality.[35] The author uses 1993 – 1999 data from 78 major US electric utilities from 23 states. Ter-Martirosyan finds that IR is associated with a reduction in OM&A expenditures and that reduced OM&A activities are associated with an increase in SAIDI. Importantly Ter-Martirosyan's analysis concludes that the incorporation of strict reliability standards with financial penalties into IR can offset the tendency of plans without standards and penalties to result in imprudent cuts in critical OM&A activities.[36]

In its report on 3rd Generation IRM the Board stated that the Distribution System Code had been amended with the addition of mandatory customer service performance standards and indicated that it expected similar amendments related to service reliability performance standards.[37] However, notwithstanding the above statement, the Board's 2000 decision had in fact already put in place mandatory reliability standards.

Joskow observed that there has been a shift of focus from reducing operating costs to investments and service quality, but that service quality considerations appear to be added to cost reduction mechanisms and do not effectively incorporate customer valuation.[38]

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.

… 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.

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[35] Ter-Martirosyan, A., *The Effects of Incentive Regulation on Quality of Service in Electricity Markets*, George Washington University Dept. of Economics Working Paper, Presented at International Industrial Organization Conference, North Eastern University, Boston, 2003.
[36] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 3. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF
[37] EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 43.
[38] 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. Pages 83-84.

In Ontario, service quality is not even “bolted to” an IRM focused on cost reduction as illustrated by the lack of recognition of the link between cost and service quality performance, the lack of incentives (rewards/penalties) for service quality performance, and the general lack of vigilance in the Board’s SQR. Even worse is the interpretation by some distributors that the minimum standard guidelines for service reliability performance accommodate service degradation. The PWU’s December 20, 2011 submission in the Board’s consultation on *Phase 2 - Initiative to Develop Electricity Distribution System Reliability Standards* (EB-2010-0249) illustrates how the current guidelines can be interpreted as accommodating service reliability deterioration.[39]

In a submission filed by the PWU in the first phase of the Board’s consultation on system reliability standards (EB-2010-0249) Dr. Cronin indicated that reliability performance has deteriorated in Ontario between 2000 and 2008. Relative to the mid-1990s, the degradation is even more pronounced.

Unlike the intentions laid out in the 2000 decision on First Generation PBR, it was not until 2008 that the Board made even a cursory examination of the distributors’ reliability data that had been collected since 1999. The 2008 Board staff report[40] provided analysis on the three-year average performance for the distributors from 2004-2006. That analysis shows that 25 to 50 per cent of the distributors fell below their minimum standards and that the distributors that fell below their minimum standards had performance levels that were 50 to 100 per cent worse than the minimum standards.

Unfortunately, information on Cause of Interruptions that the distributors are required to record but that the Board has not collected is not available for qualitative analyses of the observed performance. The PWU believes that it is imperative for the Board to collect the Cause of Interruption information and conduct a complete analysis of the

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[39] EB-2010-0249. Ontario Energy Board Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards. Submission of the Power Workers’ Union. December 20, 2011. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/PWU_Comments_20111220.pdf

[40] EB-2008-0001. Ontario Energy Board. Staff Discussion Paper. Regulation of Electricity Distributor Service Quality. January 4, 2008.

distributor's service reliability performance in order to determine the RRFE's service reliability performance start point. In the absence of such an analysis it is not possible for the Board to assess the scope of any change in service reliability performance required to address customer expectations determined through WTP surveys, and the impact on rates.

While it is recognized that the measurement of service reliability performance is impacted by advances in monitoring technology, it is unlikely that all trends in service reliability performance measured are solely technology related. The wide use of the service reliability metrics used by the Board (i.e. SAIDI and SAIFI) in other jurisdictions is indicative of the acceptance of these metrics in assessing service reliability performance trends. If the Board believed that negative trends in service reliability performance statistics is solely a function of improved monitoring technology it would bring into question the Board's SQR that bases service reliability performance on SAIDI and SAIFI as a backstop to IR's financial incentive. In the PWU's view, rather than assume that increases in SAIDI and SAIFI are technology related, the Board should require distributors to provide evidence on the impact of any technology changes that they have made on their performance statistics.

7.1 Service Quality Performance Incentives

Rewards and penalties for service quality performance provide utilities with the incentive to maintain or improve performance. The scope of the rewards and penalties determines the effectiveness of the incentives and like the standards should be based on the value that customers attach to service quality.

The scope of Ofgem's incentives around service quality performance is substantial and illustrates the weight that Ofgem attaches to service quality performance. Joskow[41] describes Ofgem's approach to service quality incentives for the UK RECs as involving several dimensions of performance with an overall revenue impact of

[41] 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.

penalties of about 4 per cent of total revenue while the revenue impact of rewards 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.**

In the PWU's October 29, 2010 submission on service reliability, Dr. Cronin described approaches used to mitigate profit-driven OM&A cuts in North America and Europe. Approaches used by members of the Council of European Energy Regulators ("CEER") involved system-wide standards with penalties and single-customer guarantees for payment for non-performance:

> **Regulators in both North America and Europe have responded to profit-driven OM&A cuts with new regulatory initiatives. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed mandates on the utilities covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations. In Europe, regulators such as the Council of European Energy Regulators ("CEER") have documented and encouraged the adoption of SQR which combines system-wide standards with incentive/penalty schemes as well as single-customer guarantees with monetary payments for non-performance. Some regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements or interruption avoidance.**[42]

Dr. Cronin observed that some regulators have incorporated WTP information into their distribution price regulation while one regulator has set a goal of achieving the optimal level of reliability that recognizes customers' interruption costs. Dr. Cronin suggests the use of Single-Customer Guarantees in Ontario until such time when the Board has developed incentives based on WTP surveys.

> **In the short run, and in the absence of a more robust incentive regime, Ontario distributors' should face financial penalties for non-compliance with mandated minimum reliability standards. In the medium run, the Board should adopt SQR which combine reliability standards with penalty schemes as well as single-**

[42] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 5. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

> **customer guarantees with monetary payments for nonperformance. The latter guarantees/payments should be based on some robust measure of customer interruption costs. In the long run, my preference is to develop an incentive approach that internalizes the cost of supply interruptions; i.e., within which LDCs recognize O&M, capital, and customer interruption costs. The Board should move toward the implementation of a "socially optimal" level of reliability; not too little, not too much. Such regimes have been successfully implemented by a number of regulators. These efforts have been under way for years and are well documented (see for example Council of European Energy Regulators).[43]**

The evidence on the need for service quality performance incentives as a backstop to utility cost cuts in response to IR's financial incentive is clear and the PWU submits that it is essential for the Board to include service quality performance incentives in the RRFE. To do nothing is akin to abandoning SQR and limiting the Board's role to the collection of service reliability data.

7.2 Customer Valuation based on WTP Studies

Utilities and regulators in North America have undertaken WTP studies for many years. Regulators in Great Britain, Norway, Italy and Sweden among others have conducted studies to determine the value that customers place on service quality and the amount they are willing to pay for service improvement based on WTP studies. Some of the regulators have taken the WTP information and incorporated the values into their distribution price regulation.[44]

The PWU submits that it is necessary for the Board and the utilities to establish the value that customers put on service quality. Customer valuation based on customer WTP surveys should be used to establish customer expectations and the level of service quality that customers are willing to pay for. The outcome of the WTP

[43] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page ii. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[44] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 35. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

surveys should form the basis for the distributor's investment planning process, and asset condition management as they have been in other jurisdictions.

To ensure that service quality is considered in its central role in the regulation of the utilities the Board's RRFE consultation needs to include an initiative on service quality that will establish customer value and expectations through robust customer WTP surveys.

As the PWU noted in its submission in Phase 2 of the Board's Service Reliability consultation, Pollara's customer surveys commissioned by the Board, which solicited the opinions of 905 residential customers and 301 business customers across the province is a good first step that the Board will have learned from in developing a robust and transparent WTP survey.

Dr. Cronin raised questions on the Pollara study that the Board should address in developing WTP surveys including the following: [45]

- Extent of strategic bias;
- Gaming and free rider issues;
- Details on sampling and questionnaire implementation;
- Interview training to provide context around the results;
- Information on how the survey data translate into the Ontario distribution customer base;
- Scoring/ranking approach; and,
- Correlation of expressed WTP with customer's outage experience.

At the Board's December 9, 2011 information session on the RRFE the PWU asked Board staff whether Pollara's survey data could be made available to stakeholders. Board staff indicated that the data remains with Pollara and suggested that there might be customer confidentiality issues around sharing of the data. In the PWU's view survey data can be shared without providing information that identifies a

[45] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Pages 41 to 43. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

customer. How data can be shared publicly is an issue that the Board should deal with in developing a robust WTP survey so that the actual survey results can be shared with stakeholders and provide transparency to the WTP survey results that will form the basis of distribution prices and service quality standards.

7.3 Service Quality Benchmarking

As noted earlier in Section 6.2, the Board's partial cost benchmarking approach not only ignores a substantial portion of the distributors' costs i.e. capital costs, it also ignores the essential link between cost and service quality performance.

In Attachment A Dr. Cronin illustrates how the Board's benchmarking approach has resulted in the mis-classification of distributors with higher service reliability performance as less efficient than distributors with lower service reliability performance and has penalized them with higher productivity stretch factors.

The PWU submits that it is essential for any benchmarking approach included in the RRFE to factor in both total cost and service quality performance to provide the appropriate cost efficiency incentive.

8 LINE LOSS PERFORMANCE

As noted in Section 4, the RRFE needs to incorporate line losses. This is supported by Dr. Cronin's finding that the line loss rate among Ontario LDC's has degraded in 2009 relative to the 1995-1997 period by 33 per cent on a customer-weighted based and 20 per cent on a simple average basis (see Attachment A).

According to Dr. Cronin, Enmax Power Corporation's line loss rate fell from 3.02 to 2.83 per cent in 2010 after it entered into an agreement with stakeholders that is intended as an incentive to reduce line losses under its Formula Based Ratemaking plan. The RRFE needs to include a line loss incentive to ensure that utilities factor in line loss considerations in network investment planning. Failure to do so not only results in rate increases, but as Dr. Cronin notes, has "pervasive green implications of unnecessary energy usage".

9 APRIL 5, 2012 LETTER FROM THE BOARD - ATTACHMENT A: ISSUES FOR COMMENT

In this section the PWU provides comment on issues listed in Attachment A of the Board's April 5, 2012 correspondence related to an RRFE vision and context as well as on the issues listed under "Performance and Incentives" and "Other". The PWU's comments on "Planning" and "Rate-setting & Mitigation" issues are provided in the PWU's submissions on those respective topics.

9.1 What is your vision for a sustainable and long-term regulatory regime?

The PWU's vision for a sustainable and long-term regulatory regime for the electricity utilities is one that focuses on customer value and establishes appropriate and transparent incentives based on Ontario utility data to achieve performance levels that align with customer expectations.

9.2 What changes would be needed to evolve planning, mitigation, and performance policies towards your vision?

To achieve this vision it is necessary to recognize customer value as the key input to the regulatory framework. This key input would be obtained through robust customer WTP surveys that will establish the utilities' service quality (i.e. customer service and system reliability) standards and provide the context for utilities' network investment planning and the regulatory framework.

The OEB and utilities will need to educate customers to build an understanding of the value and costs of electricity services and the impact of Government energy policy on them. Customer WTP surveys will then form the basis for utilities' asset management and investment planning thus incorporating customer value into the utilities' determination of service quality standards and cost. Regulatory incentives and benchmarking based on empirical analysis of Ontario utility data will be used to achieve service quality and total cost performance. Standards for asset management best practices will ensure system sustainability while mitigating time and cost of regulatory review processes. To enhance the sustainability of the regulatory framework, issues that utilities are or will face (e.g. aging assets, aging workforce) should be addressed expeditiously. The framework recognizes that customers are unlikely more able to accommodate rate increases in the future than they are today and that postponing maintenance and capital investments to mitigate rate increases today compromises future service quality and results in higher future rate increases. Therefore bill impact mitigation will be limited to *ex-post* mitigation.

9.3 As a means of representing the Board's vision for the regulatory framework, Board staff prepared a strawman that summarized the key elements of the regulatory framework. In providing comments on the issues the Board would be assisted if stakeholders also provided comments in relation to this vision.

The PWU opposes the following three aspects of the strawman table.

1) **Feature: Performance Standards and Incentives**

   Model Framework: Experts retained to assess utility plans and audit utility planning processes to assess the utility's effectiveness in prioritizing and pacing network investment with regard to bill increases to consumers.

   Change: Potential for expedited review based on utility's effectiveness in prioritizing and pacing network investment with regard to bill increases to consumers.

Utilities should prioritize and pace network investment according to its asset management plan based on asset condition assessment: not based on bill increases. While utilities do consider bill impact in investment planning, prioritization and pace of network investment should be based on the value customers place on service reliability determined through WTP surveys. Any mitigation of bill increases required should take place after (i.e. *ex-post*) such a network investment planning process and the regulatory approval process in order to ensure sustainability of the system at levels that provide for service quality performance valued by customers. Mitigating bill increases as a part of (i.e. *ex-ante*) the planning process will result in service performance at levels below customers' expectations and that they are willing to pay for.

2) **Feature: Approach to Rate Setting**

Model Framework: Partial PBR - OM&A is indexed to performance outcomes and a productivity measure; capital based on approved plan is a pass-through.

Change: Sever treatment of OM&A and capital to increase pursuit of operating efficiencies and recognize significant need for capital investment.

The RRFE should provide for regulatory certainty that will provide the incentive for long term structural change and increased efficiency. Efficiencies should be driven through Incentive Regulation on total cost. Applying IR to O&M only creates an incentive to transfer costs from O&M to Capital that incentivizes cost allocation inefficiency that results in higher costs for customers over the long term. It also creates intergenerational inequity with a disproportionate amount of costs imposed on future customers. Further, there are similar issues related to O&M related to the replacement of aging assets as there are with the need for incremental capital investments. In addition there is the significant issue of replacing an aging workforce and the need to attract additional skilled workers for the incremental work that will have significant impact on O&M.

IR on total cost plus an improved incremental capital module would be appropriate.

3) **Feature: Total Bill Mitigation**

Model Framework: Ex-ante and ex-post; total bill considered.

Change: Ex-ante added. Changes in all charges considered.

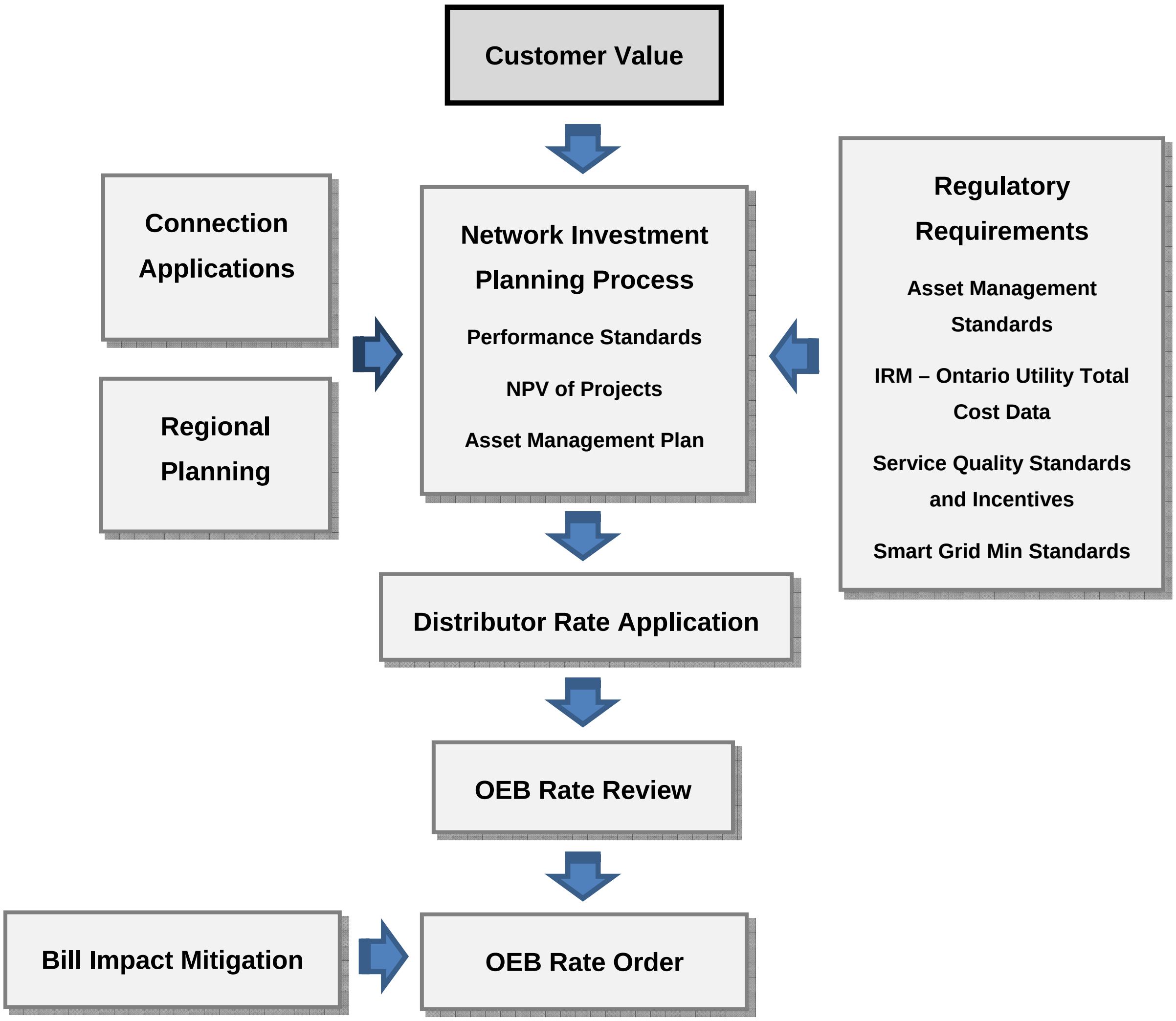
The PWU does not support *ex-ante* bill mitigation as it impacts the utility's business planning (e.g., investment plan, asset management) and puts at risk long term system sustainability and service at levels expected/valued by customers. It would impede the efforts required to address the significant issue of replacing aging assets and an aging workforce. To ensure a sustainable electricity industry the Board needs to address this urgent issue and in doing so recognize the potentially catastrophic outcome of postponing the required capital investments until such time when service reliability deterioration is evident. *Ex-ante* bill mitigation would result in the postponement of investments. The impact is exacerbated where the utility's mitigation must also address increases in bill items that are not the utility's bill items (i.e. electricity price). Utilities do consider the total bill impact of their investment plans, which they have control over. The utility should not be responsible for mitigating bill line items that it has no control over through the mitigation of its rates. Further, *ex-ante* bill mitigation exacerbates the impact of revenue disallowances that are the outcome of cost of service reviews on a utility's ability to sustain and develop the system.

The PWU position on the strawman flow chart is as follows:

- The customer expectations/value determined through WTP surveys is the start point;
- The regulatory framework would include asset management standards; total cost performance incentives (IRM) based on Ontario utility data; service quality standards and incentives; and smart grid minimum standards; and,
- *Ex-post* mitigation

The PWU's RRFE model flow chart is illustrated below.

PWU Proposed Model



9.4 What outcomes for customer service and company cost performance should be established?

The PWU assumes that the reference to customer service is to service quality (i.e. customer service and service reliability).

As discussed in Section 7.2, in order to establish the outcomes for service quality performance and utility cost performance it is necessary to understand customer value and expectations of electricity service. Customer valuation should be based on WTP surveys that establish the level of service reliability that customers are willing to pay for which would form the basis for the distributor's investment planning process, asset condition management as other jurisdictions have done.

Once costs associated with the service quality levels that customers value and expect have been determined through asset condition management and network investment planning the outcome of cost performance should be established through an IR approach that uses the distribution industry IPI, TFP based on Ontario utility data. This will provide the appropriate incentives for cost efficiency. If benchmarking is to be part of the IR framework it should be based on total cost and account for service quality performance (see Section 6). Thus it is a properly constructed IRM that will provide the incentives for the desired cost performance outcome – cost efficiency.

Beyond implementing the IR framework the Board should desist from micromanaging the utilities' business in the guise of guidance on cost performance. This includes refraining from the Electrical Contractors Association of Ontario's ("ECAO") submission at the March 28-30 RRFE consultation meetings for prudence reviews on utilities' use of best practices, including the requirement to demonstrate procurement processes based on the competitive marketplaces.

The ECAO's submission would require utilities to spend considerable amounts of time and money to carry out detailed assessments of every potential capital project to determine whether to use their in-house workforce or a contractor.

Utilities know their businesses and they know the strengths and weaknesses of their in-house resources. They know them because they have organized them in ways to provide the best services at the best price. Each utility has differences in their approach to capital work depending on their size, availability of in-house skills and casual skills for a particular project, and availability of equipment among other factors. Most capital projects fall into a few categories of typical utility capital projects for which most utilities have taken great effort and time to develop their own approaches to avoid exposure to unnecessarily high costs of contractors for certain types of projects and for staffing work spikes.

The ECAO suggests that when a contract is not contracted out, utilities should be required to demonstrate the economic efficiency of the project costs and assess the reasonableness of the costs against competitive market prices. Typically in-house and contractors' labour rates and skills are similar; however, familiarity with the assets is an advantage to the in-house workforce. Even if labour rates and skills and other factors appear reasonably equal the contractor builds a profit margin into the price that is not applicable to the in-house approach. In addition, there is often more control over the progress of the job if it is done in-house. In any case, when the in-house workforce is not available to handle a project at the time required, the work would likely be contracted regardless of whether costs would have been lower or higher in-house. Against this reality, it would make more sense that regulated entities should be required to demonstrate the economic efficiency of the project costs when they are contracted out. However, in the PWU's view the assessment suggested by the ECAO would unnecessarily drive costs up through regulatory process.

Established correctly, it is the IRM that should incent utilities to make cost efficient business decisions. Micromanagement broadly applied by the Board without consideration for individual utility circumstances can take away from a utility's ability to achieve the efficiency implicit in the IRM and the service quality performance that customers expect. Business decisions are best made by the utility to get the best outcomes – there are too many scenarios for the Board to prescribe the best approach and get it right. Therefore, flexibility in the management of the utilities' area of expertise should be left to the utilities.

9.5 What standards and metrics for customer service and company cost performance should be established in regard to these outcomes? How do the performance benchmarks that are in place today relate to your proposed metrics?

Standards for the service quality (i.e. customer service and service reliability) performance metrics that the Board has had in place since 2000 should be established based on customer WTP surveys to provide for service at levels that the customers value and expect. The Board already has a long history on the distributors' service quality performance based on these metrics that will allow for the assessment of the impact of the Board's regulation on the service quality performance. Therefore the current metrics should remain in place.

As submitted in Section 8, the RRFE needs to include an incentive on line losses to ensure that utilities factor in line losses in network investment planning given the deterioration in distribution line losses in Ontario (see Attachment A). Line loss performance would complement the existing service reliability performance metrics in serving as a backstop to IR's financial incentives and in ensuring the ongoing sustainability of the systems.

It is necessary to recognize that true ranking in the Board's current cost performance benchmarking is impacted by service quality performance. Therefore in ensuring that benchmarking creates the correct incentives service reliability performance must be factored into the benchmarking approach (see Section 7.3). In addition it is imperative that any cost benchmarking is based on total cost to provide the incentive for cost efficiency and not for inappropriate cost allocation that results in higher costs in the long run (see Section 6.2).

9.6 What are the characteristics of a "high-performing regulated entity" (i.e., what specific metrics can be used to evaluate the level of performance of the regulated entity)?

A "high-performing regulated entity" is a utility that is performing at or close to the productivity frontier determined through TFP analysis while providing service quality (Board's current metrics plus Line Losses) at levels that customers value determined through customer WTP surveys.

9.7 What incentives, if any, are appropriate to reward utilities for cost-effective and efficient performance, including appropriate rewards for exceeding standards for customer service, and company cost performance? What incentives, if any, are appropriate for the purposes of rewarding performance with regard to multi-year capital programs?

Financial rewards are appropriate for cost-effective and efficient performance, as well as for exceeding standards for service quality and expectations on cost performance. Since cost performance that exceeds the IRM's productivity factor results in higher returns, allowing the utility to keep the incremental return would not result in incremental cost to the customers while providing strong incentive for utility productivity improvement.

Financial incentives are also appropriate for rewarding cost performance of multi-year capital programs.

9.8 How might the Board enhance the alignment of customer and company interests through the use of incentive mechanisms?

Customer and utility interests can be aligned through the use of incentive mechanisms by explicitly embedding customer valuation of service quality determined through WTP surveys into the rate setting process (see Section 7.2). Incentive mechanism for service quality performance would be based on performance standards established through the customer WTP surveys while the IR price cap would provide the incentive mechanism for cost efficiency.

Other

9.9 In light of what you heard at the March 28-30, 2012 Stakeholder Conference, what are your priorities for the Board's development of the RRFE and how might the Board manage the transition to the renewed regulatory framework in a manner consistent with your priorities?

Priority needs to be given to the replacement of aging assets and an aging workforce within the 3rd Generation IR term. Consistent with the PWU's vision and context, for the transition to the RRFE the Board will need to:

- Work with the utilities on educating customers to build an understanding of the value and cost of electricity and the impact of Government energy policy on them;
- Conduct customer WTP surveys;
- Develop standards for utility asset management and a self-certification process for utility compliance with the standards;
- Develop service quality standards and incentives;
- Develop line loss standards, performance metrics and incentives; and,
- Develop a total cost IRM based on Ontario utility data.

9.10 Are there other key issues that should be considered in the development of the RRFE?

In developing the RRFE the Board should address the issue of what the impact of its regulation of the electricity utilities has been to date on their cost and service quality performance. This issue should be addressed through research and analysis of all the utility data that the Board has in its possession including the data the Board collected for First Generation PBR. Doing so will help the Board understand the start point for the RRFE and allow it to assess the impact of the RRFE going forward.

10 ISSUES FOR COMMENT AND POTENTIAL REFINEMENTS TO FOUNDATIONS IN PLACE

10.1 What should the Board consider when setting new or refining existing standards and measuring standards for service and/or cost performance for distributors and transmitters?

The PWU provided comments on the issue of setting new or refining existing standards and measuring standards for service performance for distributors in its submission in phase 2 of the Board's consultation on service reliability standards.[46] The PWU identified the need for the Board to leave the existing guidelines on service reliability reporting requirements in place to ensure data continuity that allows for trend analysis of the distributors' service reliability performance. In addition, the PWU identifies the need to require distributors to report all records of Cause of Interruption collected since the implementation of the Board's service reliability regulation in 2000 to allow for comprehensive (i.e. quantitative and qualitative) assessments of the distributors' reliability performance. If the Board is keen on having standardized reliability measurements for the purpose of benchmarking the distributors' reliability performance, additional metrics should be introduced for which the Board would need to ensure that data collection amongst the distributors is consistent. In doing so, the differences in geographic and environmental conditions that impact a distributor's service reliability performance must be factored in. For the existing metrics, distributors should continue with their existing data collection practices, and minimum performance standards should continue to be based on a distributor's own historic performance. The PWU also commented on the need for clarification on the existing minimum standards guidelines for System Average

[46] EB-2010-0249. Submission of the Power Workers' Union. Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards.

Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"), to ensure that they are not interpreted as accommodating service reliability deterioration.

The PWU's views on cost performance are presented in Section 6. The PWU believes that the Ontario distribution industry's IPI should be used to properly reflect the changes in the distributors' input prices, and to provide the appropriate input price benchmarks and avoid the risks associated with the use of a macroeconomic index. The TFP approach should be based on empirical data analyses using Ontario distributors' data that the Board has in its possession, including pre-2002 data. Further, in recognizing the direct link between cost and service performance, benchmarking should be based on total cost and factor in service quality performance.

For effective service quality regulation it is imperative that the RRFE ensures compliance with performance standards through incentive mechanisms i.e. penalties and rewards.

10.2 What should the Board consider when developing appropriate incentives to transmitters and distributors for cost-effective and efficient performance, including appropriate rewards for exceeding the standards?

In developing appropriate incentives for cost-efficiency and service quality performance, it is essential for the Board to determine customer valuation of service quality through WTP surveys (see Section 7.2). Incentives for service quality performance are necessary to discourage utilities from sacrificing service quality in pursuit of IR's financial incentives. Single Customer Guarantees can be developed as an interim measure to customer valuation through WTP surveys.

To ensure cost efficiency the cost performance incentives (i.e. IPI, TFP, productivity stretch factors) must be based on Ontario distributors' total cost empirical data analyses, including the pre-2002 data (See Section 6). Doing so sets total cost efficiency targets that are reasonably achievable by providing the appropriate incentives for both allocative and operational efficiency.

As an alternative to cost benchmarking the Board can provide for self-selection of cost performance incentives by setting out a menu of options that a utility can select from at the start of the IR term that provides for higher allowed returns with the selection of a higher productivity factor than the TFP in the IRM. Since utilities can be expected to select an option that it can reasonably meet, the self-selection approach would be a vastly superior alternative to a flawed benchmarking approach (i.e. benchmarking based on partial cost and that ignores service quality performance) while providing incentive for utilities to meet their efficiency potential.

10.3 What should the Board consider in relation to when and how it might assess utility performance?

Since the inception of the Board's regulation of the electricity utilities it has not conducted a comprehensive assessment of their performance. In the PWU's view a comprehensive assessment of the electricity utilities' cost and service quality performance, as well as asset condition management over the period that the Board has had its regulatory authority is overdue. Such insight will provide invaluable input into the development of the RRFE.

With the long life cycles of most of the utilities' assets (e.g. poles, conductor, transformers) it is necessary to assess the distributors' asset condition management because impacts of the rate freezes and price caps that the utilities have been subject to are unlikely to be fully manifested until sometime in the future. However, the impact on a utility's asset condition management that in turn impacts future costs and service quality performance can be assessed today. This assessment will provide an understanding of the condition of the systems based on empirical evidence that will add to the practicality of the RRFE and allow for the assessment of the effectiveness of the RRFE.

In reviewing the utilities' performance, the Board must recognize the link between cost and service quality performance. In a PWU submission to the Board Dr. Cronin provides the following comments on the multi-dimensional nature of distribution output and just and reasonable prices that requires the simultaneous evaluation of rates, reliability and costs:

> **Electric distributors produce and sell a multi-dimensional output to their customers. Clearly, the level of service reliability and voltage quality, among other factors, can vary substantially among LDCs, producing different products (i.e. service reliability levels) depending on the mix of characteristics delivered to the customers. These different bundles of characteristics would likely have different costs associated with them, and thus result in differences in distribution rates. In evaluating the reasonableness of a distributor's rates, we need the context of the "whole package(s)" being delivered to its customers. Rates, reliability, and costs must be evaluated simultaneously.**[47]

In quantifying cost performance the Board should update the empirical TFP research and analysis that the Board conducted for First Generation PBR, properly consolidated for the amalgamations, mergers and acquisitions that have occurred in the distribution sector since that time. As the pre-2002 data was used in the First Generation PBR TFP approach, the use of this data will provide for apples-to-apples analyses of the distributors cost performance.

Assessment of a distributor's service reliability performance should be against its own historic performance and individual minimum standard consistent with the intent of the Board's service reliability guidelines. In considering the quantification of service reliability performance the PWU refers the Board to Dr. Cronin's evidence filed by the PWU on October 29, 2010.[48] The analysis conducted by Dr. Cronin on a composite basis should be undertaken to assess individual distributor's service reliability performance since the implementation of service reliability standards in 2000. In addition, as noted in Section 7 the Board should collect the Cause of Interruption data that the distributors have been required to record since 2000, for comprehensive quantitative and qualitative analyses of the distributors' performance.

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[47] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 2. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[48] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

Given the different factors that can impact a distributor's service reliability that are outside of the control of the distributor, a qualitative analysis of the statistics is necessary for a fair evaluation of the distributor's performance.

Following a first review such as described above, the Board should conduct regular reviews of the distributor's performance based on the utilities' annual RRR filings. This allows the Board to stay on top of the utilities' performance and take corrective action and apply penalties in a timely manner. Such vigilance will enhance the Board's regulatory effectiveness as well as facilitate the review of the effectiveness of the Board's regulatory framework.

Given that service deterioration related to IR's financial incentive may not manifest itself until a future period the review of the distributors' asset condition assessment should be a part of the assessment of utility performance.

10.4 In light of the objectives for a renewed regulatory framework for electricity, do the Board's existing "standards", described in section 4.2.1, continue to effectively capture a holistic view of utility performance (e.g., financial, operating, etc)? If not, what standard(s) for service and/or cost performance might be appropriate, how/when would the standard(s) be determined, and what are the implications, advantages and disadvantages of such standard(s)

The objective of the RRFE as articulated in the Board's November 8, 2011 Notice "is to encourage and facilitate greater efficiency through a focus on performance-based outcomes and a disciplined, long-term approach to network investment planning." The objective is intended to "help ensure the reliable and cost-effective delivery of electricity to Ontario consumers".

Section 4.[1].1 of the Performance Discussion Paper lists the objectives that are a result of recent amendments to the *Electricity Act* as follows: conservation; promotion of renewable generation; and, technological innovation through the smart grid. Section 4.[1].1 goes on to state:

> **As a consequence, what a "standard transmitter" or a "standard distributor" is within the scope of defining and measuring performance (i.e. what functions carried out by the companies should be measured) may need to be reviewed.**

Such a review would identify any new or changed functions carried out by the companies that should perhaps be included in performance review analyses/benchmarking models. ..."[49]

The PWU is of the view that while the new obligations create new incremental costs, they do not create new functions for the transmitters and distributors. Therefore the Board's existing "standards" continue to effectively capture a holistic view of utility performance.

The costs associated with the objectives that result from the amendments to the *Electricity Act* are subject to 3rd Generation IRM's price cap (i.e. cost performance standard) if the costs for these new obligations are included in a distributors base rates for 3rd Generation IRM. For costs of the new obligations that arise over the course of the IR term that are not included in the IR base rates, the Board could add incremental cost modules/rate riders to cover the incremental costs over the course of the IR plan. The efficiency measures undertaken by the utilities in response to the IRM would be company-wide and further efficiency requirements should not be imposed on the incremental costs. The effect of doing so would be akin to disallowance of reasonable costs.

10.5 In its review and approval of costs associated with investment plans, what methodologies and approaches might the Board use to develop an empirical approach to help it determine appropriate cost levels? Can the Board's utility cost comparison and benchmarking work be used to help size cost envelopes?

The PWU proposes an approach similar in concept to Ofgem's implicit requirement for Publicly Available Specifications 55 ("PAS 55") to help the Board determine appropriate cost levels associated with investment plans.

The PWU proposes that the Board set standards for asset management that incorporates customer valuation of services determined through WTP surveys, and

[49] EB-2010-0379. Ontario Energy Board. Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors. November 8, 2011. Page 54.

that embed economic efficiency and cost effectiveness principles. A distributor's conformance with the Board's standards would be established through a utility self-certification process. Verification of adherence to the self-certification process in the Board's review process would qualify the distributor's investment plan for an expedited review in the cost of service proceeding.

With regard to the question on whether the Board's utility cost comparison and benchmarking work can be used to help size cost envelopes, the PWU notes that the Board's cost comparison and benchmarking work is currently based on OM&A costs instead of total cost. In addition, the Board's benchmarking approach ignores the link between cost and service quality performance. Therefore, the use of the Board's utility cost comparison and benchmarking work is not appropriate for use in sizing cost envelopes.

This is discussed in more detail in the PWU's submission on the RRFE initiative on Distribution Network Investment Planning (EB-2010-0377).

10.6 In addition to the CDM targets, are there any other "Core performance standards" that should be encouraged through the use of specific incentives? If so, what incentive(s) might be appropriate, how/when would it be determined, and what are the implications, advantages and disadvantages of such an incentive?

Reduction of line losses needs to be encouraged through incentives. (see Sections 8 and 9.5).

10.7 How might the standards for performance discussed in section 4.2 and the various empirical tools discussed throughout the paper further inform (a) utility planning processes, (b) utility applications to the Board, and/or (c) the Board's review processes?

As set out earlier in this submission, the PWU's view is that service quality at standards that customers value and expect, determined through WTP surveys should be the basis of the utility's investment planning process. The investment plan that responds to the customers' valuation of service standards would then form the basis for the distributor's cost of service rate application. The PWU proposes that verification of the distributor's adherence to the self-certification process for conformance with Asset Management Standards established by the Board should qualify the distributor for an expedited review of its investment plan (see Section 10.5).

10.8 What conditions would have to be met to "fast-track" an application?

Please see the PWU's response in Section 9.5

All of which is respectfully submitted.

ATTACHMENT A: ASSESSING DISTRIBUTOR INCENTIVES AND PERFORMANCE: 2000 TO 2012 BY F. J. CRONIN

Assessing Distributor Incentives and Performance: 2000 to 2012

By

F. J. Cronin

For

The Power Worker's Union

April 20, 2012

1. Introduction

In the Board's consultation on 3rd Generation IRM I had provided comments on a wide range of issues fundamental to properly establishing an incentive scheme for LDCs, their shareholders and their customers (Appendix A). In this attachment to the PWU's submission on the Ontario Energy Board's (Board) initiative on Defining and Measuring Performance of Distributors and Transmitters (EB-2010-0379) in the Board's consultation on a Renewed Regulatory Framework for Electricity Transmitters and Distributors I provide an assessment of the Board's incentive regulation and the impact it has had on the Ontario distributor's performance based on empirical data analysis. In particular I examine: the change in the distributors TFP; the impact of O&M benchmarking on labour capitalization and cost shifting; the change in line losses; and, the ranking errors resulting from OM&A rather than total cost benchmarking.

2. Summary and Conclusions

In 2008 I recommended the OEB implement total cost benchmarking with appropriate service quality regulation. 1st Generation research had also established the importance of appropriate incentives for all LDC inputs including line losses. I had deep reservations regarding the proposed scheme and O&M benchmarking including:

- it was inherently flawed with systemic incentive failures,
- it would likely lead to negligible productivity gains,
- it would dis-incent permanent productivity improvements with a 3-year On, 1-year Off schedule
- it was inequitable to stakeholders
- it would reward inefficient LDCs (on a total cost basis) while penalizing efficient LDCs (on a total cost basis)
- it would produce phantom efficiencies and "cost savings"
- it would incent cost shifting from O&M to capital "to beat the system", which simply represented accounting ledger changes; the only uncertainty was how massive a shift would occur,[1]
- it would raise rates in the future as expensed costs were capitalized,
- it would raise rates in the future as LDCs' earnings grow to cover the increased rate base,
- it would add unnecessary, imprudent "capital costs", further exacerbating allocative inefficiency and increasing rates for customers,[2]
- it would contaminate capital additions data and obscure comparisons to earlier periods since more recent capital additions have significantly larger labour & overhead components,

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[1] My research on input substitution demonstrated that the elasticities of substitution were notable. This indicated that the inherent, broad operating flexibility could permit very substantial shifts from O&M into capital; the cost shifting would incent even further moves along the capital-labour isoquant.

[2] For a subset of Ontario LDCs, especially those relying to a higher degree on contributed capital, allocative inefficiency was an existing problem (i.e., overcapitalized). These LDCs had responded to earlier incentives regarding contributed capital by embedding more capital than optimal in the rate base. On the other hand, responding to prior cost incentives, technical efficiency was quite high across the Ontario LDCs in the 1990s.

- it would make it more difficult to assess the appropriate size of capital additions vis a vis growth in demand, capital replacements, or degraded reliability,
- it was profoundly an environmentally unfriendly incentive framework (i.e., Non-green)
- it would degrade losses as standards for losses performance were lacking[3]
- it would degrade losses as prudent O&M costs were cut to achieve higher IR scores
- it would require larger supplies of power, network resources, and generation to compensate for the degraded system losses
- it would encourage LDCs to cut prudent costs and degrade reliability
- it would encourage some LDCs operating at or close to a socially optimal position to degrade O&M and reliability, and to cause valuations for customer interruption losses to increase.

In 2008, I offered the following conclusion regarding the Board's O&M benchmarking:

> **Systemic Risk with Improper IR:** Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labor burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labor can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we cannot assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labor capitalization rate.[4]

[3] This was quite unfortunate as the utilities had made sizeable improvements in line losses over the 1988 to 1997 period, saving customers hundreds of millions of dollars. Unfortunately, these prior savings have now been wiped out.

[4] Comments by Francis J. Cronin, In the matter of the Ontario Energy Board's 3rd Generation Incentive Regulation for Electricity Distributors (EB-2007-0673), On behalf of Power Workers' Union, April 14, 2008.

The Findings on LDCs' Performance and the OEB's IR Incentives include:

- The 2nd freeze period (2000 to 2005) produced nearly identical results to the earlier voluntary freeze in the mid-1990s: on an unweighted basis, the TFP growth was 1.86 percent per year. However, on a customer-weighted basis, the growth was notably lower at 0.57, indicating that larger LDCs on average had lower rates of productivity growth. From 2006-2010, TFP growth for LDCs under IR declined -0.24 percent per year on an unweighted basis; on a customer-weighted basis, the decline was slightly more pronounced, at -0.40 percent per year.

- A massive shift occurred between 2001 and 2010 in labour capitalization among Ontario LDCs. The average increase was 228 percent. That is, over the past decade labour capitalization rates more than tripled. Furthermore, it was not just labour capitalization that increased. The proportion of "overhead" also increased. In 2001, the share of capital comprised of overhead equaled 8 percent. By 2010, the share of capital comprised of overhead equaled 12 percent. Since the size of capital additions was higher in 2010, the increase in the amount of "overhead" being capitalized was significantly higher than 50 percent. All together, we might find that hundreds of millions of dollar per year have been shifted from expenses and capitalized. Possibly a billion dollars cumulatively. This would indeed be a troubling conclusion for its ominous implications.

- By 2009, we find widespread and substantial degradation in line losses among Ontario LDCs. For some LDCs, the degradation is over 40 percent. On a customer-weighted basis, we find losses have degraded almost 33 percent relative to the 1995-1997 period. On a simple average basis, losses have degraded almost 20 percent. Assuming no further degradation in losses since 2009 by Ontario LDCs and that power costs average $.10, over the next 5-year period the increase in power losses would cost about $541 million, or about $113 per customer.

- There is reliability degradation over the 2006 to 2010 period compared with 2000 to 2005. There is even more pronounced degradation over the 2006 to 2010 period compared with 1993/4 to 1997/98. Alberta high density LDCs' reliability is comparable to the 1993/4 to 1997/98 Ontario performance and notably better than the 2006 to 2010 Ontario performance. Alberta low-density LDCs' reliability is also better than the Ontario low-density LDCs' reliability performance. Both Alberta and Ontario LDCs tend to have better reliability performance than a set of Northern US LDCs. Distribution rates in both Alberta and Ontario are lower than a set of Northern US LDCs.

- In 2010, we find the IR O&M efficiency of the LDCs' rankings are random. Some LDCs which the Board has judged as efficient based on O&M costs are actually at the bottom of the total cost rankings (i.e., costs with capital included). Similarly, some LDCs which the Board ranks as inefficient based on O&M costs are actually among the most efficient based on total costs (i.e., costs with capital included). About 50 percent of the rankings are incorrect.

- Due to these inequities on rankings and perverse associated incentives the OEB should end its O&M IR. The OEB should move to incorporate the decades of capital data that was specifically collected from the LDCs (capital back to the 1970s) into a total cost assessment. The benchmarking should include line losses as well as reliability. Reliability performance should incorporate the LDC's own performance (e.g., SAIDI) as well as the valuations that customers attach to interruptions. Customer valuations for interruptions can be determined through such contingent market methodologies as willingness to pay (WTP) studies.

3. Incentives and Performance Assessment: 2000 to 2010

Below we assess the impacts of some of the key performance metrics over the past 5 and 10 years. These include the growth (or decline) in total factor productivity (TFP), partial cost (i.e., O&M) benchmarking, labour capitalization and cost shifting by LDCs, line losses, rates, and reliability.

3.1 Evaluating Total Factor Productivity Performance among Ontario LDCs over the 2000 to 2010 Period

Exhibit 1 presents our TFP estimates from seven sets of data on Canadian LDCs. First, we present findings from the 1st Generation PBR analysis that underlay the Board's January 2000 PBR Decision: the TFP growth rates under both COS (1988-1993) and variable productivity factor ("PF") PBR (i.e., rate freeze) from 1993-1997. Second, we present findings from the 2nd rate freeze covering 2000-2005. We do this for both LDCs that migrated onto IR subsequently as well as an LDC that operated under COS over the 2006-2010 period.[5] Third, we present TFP estimates for the period 2006-2010 covering both the LDCs operating under IR (2nd & 3rd Generations) as well as an LDC that operated under COS over the 2006-2010 period. Finally, we present TFP estimates for one Alberta LDC (i.e., Enmax Power Corporation ("EPC")) over the 2001-2009 period. EPC was of course under COS for the majority of this period; in 2007, EPC applied for permission to operate under PBR.

Compared to the variable PF PBR (i.e., freezes) periods from 1993-1997 and 2000-2005, we label the 2006-2010 period in Ontario "weak or mixed IR". Since 2000, Ontario LDCs have been subjected to repeated and near constant changes in rate regulation, including: rate freezes, 1st Gen with a blended IPI and 1.5 X factor; rate roll backs of phased market-based ROE; 2nd Gen with GDPPI and 1.0 X factor; rate rebasing/COS; 3rd Gen with GDPPI and variable X on O&M only; and a 3-year on, 1-year off schedule switching back and forth from COS to IR. Let's examine the TFP performance over the 1988-2010 period under the varied regulatory schemes.

Initially under COS, we see the TFP performance was -0.1 percent per year from 1988-1993. The initial voluntary rate freeze period (1993-1997) produced a pervasive TFP growth of 2.1

[5] Recall the province's two largest LDCs remained largely under COS during the 2nd and 3rd generations.

percent. This growth was nearly identical for different sized utilities, different aged utilities, and different output growth utilities.[6]

2000 to 2005. The 2nd freeze period examined (2000 to 2005) produced nearly identical results to the earlier freeze: on a weighted basis, the TFP growth was 1.86 percent per year. However, on a customer-weighted basis, the growth was notably lower at 0.57, indicating that larger LDCs on average had lower rates of productivity growth. We can also look at an LDC which subsequently operated under COS during the later IR terms. For this LDC, we see that its TFP growth was 0.77 percent per year during the freeze.

2006 to 2010. What about the performance of the LDCs over the periods for 2nd and 3rd Generation IR? From 2006-2010, we see that the TFP growth for LDCs under IR declined -0.24 percent per year on an unweighted basis; on a customer-weighted basis, the decline was slightly more pronounced, at -0.40 percent per year. We believe that a number of factors contributed to these declines in productivity. A number of these factors we raised in the 2007 and 2008 proceedings.[7] We will explore some of these further below.

Factors Affecting the Decline in TFP in the 2006 – 2010 Period. We see that over the second half of the decade, the rate of TFP growth falls 2.1 percentage points from 1.86 to -0.24. We can generally categorize the factors affecting this decline into regulatory and non-regulatory causes. Any factor affecting either the output or the inputs of LDCs would impact TFP growth rates. On the output side these include both economic (e.g., cycle) and demographic (e.g., population). On the input side these include such factors as institutional (e.g., hiring and training replacement workers for retirees), technical (e.g., capital additions for network replacement),[8] and mandates (i.e., required expenditures that LDCs are obligated to undertake). There is reason to believe that the magnitude of these factors could be estimated.

[6] F. Cronin, et al. "Productivity and Price Performance for Electric Distributors in Ontario," OEB Staff Report, July, 1999.

[7] Comments by Francis J. Cronin, In the matter of the Ontario Energy Board's 3rd Generation Incentive Regulation for Electricity Distributors (EB-2007-0673), On behalf of Power Workers' Union, April 14, 2008.

[8] Of course, the impact of cost shifting from O&M into capital additions would need to be sorted out as well. Below, we estimate the extent of the cost shifting.

But what about the regulatory impacts on the decline in the rate of TFP growth? I believe that a number of regulatory design choices over the 2006-2010 period negatively impacted LDCs' performance. These include:

- systemic incentive failures;
- dis-incent permanent productivity improvements with a 3-year On, 1-year Off schedule; in fact, rate increases in the COS rebasing year average about 13 percent;
- constant changes to regulatory framework and governance;
- incent some LDCs to make non optimal changes to their capital – labour mix;
- add unnecessary, imprudent "capital costs", further exacerbating allocative inefficiency and increasing future rates for customers.[9]

Pre-2000, losses accounted for about 15 percent of total distribution costs. Below, we document a degradation in losses of about 20 percent on a simple mean basis; on a customer-weighted basis, the degradation is about 32 percent. For a more representative comparison of performance in 2010 versus pre-2000, we would need to reflect an approximately 5 percent increase in costs in the 2006 - 2010 period versus say 1993 – 1997.

Adding in "Green" considerations, losses, or customer reliability valuations would make the decline in total, inclusive performance worse:

- design profoundly environmentally unfriendly (i.e., Non-green);
- design incents degraded losses as standards for losses performance were lacking;[10]
- design incents degraded losses as costs spent on O&M to improve losses are penalized by OEB;
- design requires larger supplies of power, network resources, and generation to compensate for the degraded system losses;

[9] For a subset of Ontario LDCs, especially those relying to a higher degree on contributed capital, allocative inefficiency was an existing problem (i.e., overcapitalized). These LDCs had responded to earlier incentives regarding contributed capital by embedding more capital than optimal in the rate base. On the other hand, responding to prior cost incentives, technical efficiency was quite high across the Ontario LDCs in the 1990s.

[10] This was quite unfortunate as the utilities had made sizeable improvements in line losses over the 1988 to 1997 period, saving customers hundreds of millions of dollars. Unfortunately, these prior savings have now been wiped out.

- design incents LDCs to cut prudent costs and degrade reliability;
- design incents some LDCs operating at or close to a socially optimal position to degrade O&M and reliability, and to cause valuations for customer interruption losses to increase.

How did EPC do? EPC's growth under COS was -0.17 percent per year over the whole period. In 2007, EPC applied for a PBR framework. In 2008, EPC filed an amended application for PBR. Focusing on just 2005-2009, EPC's TFP growth was 0.56 percent per year.

What can we conclude? First, a robust PBR will incent significant TFP growth; in this case it varied from 1.9 (2000-2005 rate freeze) to 2.1% (1993-1997 voluntary rate freeze). Second, constant restructuring, poor PBR design, and regulatory confusion will weaken incentives; in this case with Ontario since 2006 we see productivity growth declining, in some cases quite significantly. Third, under COS we expect little incentive for TFP growth, i.e., should see about zero growth and in the case of EPC (-0.17 %) or Ontario from 1988-1993 (-0.1 %) that is exactly what we find. Fourth, sometimes under COS results turn out worse than what one would hope for; we see that in the case of Toronto Hydro with -0.73 % per year growth.

Exhibit 1. TFP Growth: 2001-2010 for LDCs under PBR, COS and Mixed Regulation Compared with LDCs under COS 1988-1993 and PBR 1993-1997

	Ontario:[a] Rate Freeze	Ontario:[b] IR- 2nd & 3rd Gen	Ontario:[c] COS	Alberta: COS
1993-1997 (all utilities)	2.10			
2001-2005 **Simple Avg.** **Customer-Weighted**	 1.86 0.57		 0.77 (rate freeze)	
2nd and 3rd Generation IR[C] 2006-2010 **Simple Avg.** **Customer-Weighted**		 -0.24 -0.40		
2006-2010 **2001-2010**			-3.35 -1.29	
1988-1993			-0.10	
2005-2009 **2002-2009**				0.56 -0.17

[a] Since 2000, Ontario LDCs have been subjected to repeated and near constant changes in rate regulation, including: 1st Gen with a blended IPI and 1.5 X factor; rate roll backs with phased market-based ROE; COS; 2nd Gen with GDPPI and 1.0 X factor; rate rebasing; and 3rd Gen with GDPPI and variable X on O&M only.

[b] Since 2006 the Ontario LDCs have been under the OEB's 2nd and 3rd Generation IR. The former employed a rate adjustment mechanism with GDPPI and 1.0 X factor. The latter is an O&M only IR with a Rate Adjustment Mechanism based on GDPPI, an X-factor based on US LDCs' data and a variable stretch factor based on Ontario O&M cost rankings. Also, the Ontario LDCs are operating on a 3-1 schedule; i.e., three years on IR and one year on COS. All years for LDCs operating under IR 2006-2010.

[c] Ontario's 2 largest LDCs with about 2 million customers have largely been on COS since 2006. This represents all years of data for one very large LDC which remained under COS in 2006-2010.

3.2 Evaluating O&M Benchmarking and Labour Capitalization Performance among Ontario LDCs

In 2008, we discussed the issue of partial cost benchmarking in general and labour capitalization in particular. We discussed the widely varying labour capitalization among Ontario LDCs, the errors associated with O&M benchmarking, and the perverse incentives engendered by such a framework. We stated that a high probability existed that LDCs would respond to the Board's 3rd Generation IR by making accounting adjustments, i.e., moving costs from O&M to capital.

> **Systemic Risk with Improper IR:** Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labor burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labor can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we cannot assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labor capitalization rate.[11]

Of course, the likely response of LDCs to O&M benchmarking would be just to shift prior expensed costs to capital. The LDC's costs would not change at all, simply shift from one accounting ledger to another accounting ledger. What we would see looking at the lower O&M is a phantom cost saving. However, the resulting shift would be labeled an improvement in the LDC's efficiency. And under the 3rd Generation IR, the LDC would be rewarded.

While this result is not equitable there are numerous highly troubling consequences that go way beyond just an inequitable reward for one LDC. These consequences will negatively impact

[11] Comments by Francis J. Cronin, In the matter of the Ontario Energy Board's 3rd Generation Incentive Regulation for Electricity Distributors (EB-2007-0673), On behalf of Power Workers' Union, April 14, 2008.

capital additions, rates, reliability and inefficiency. LDCs' earnings will also increase if we find that O&M costs have been simply shifted from expenses to capital.

3.2.1 Massive Shift of Labour from O&M to Capital

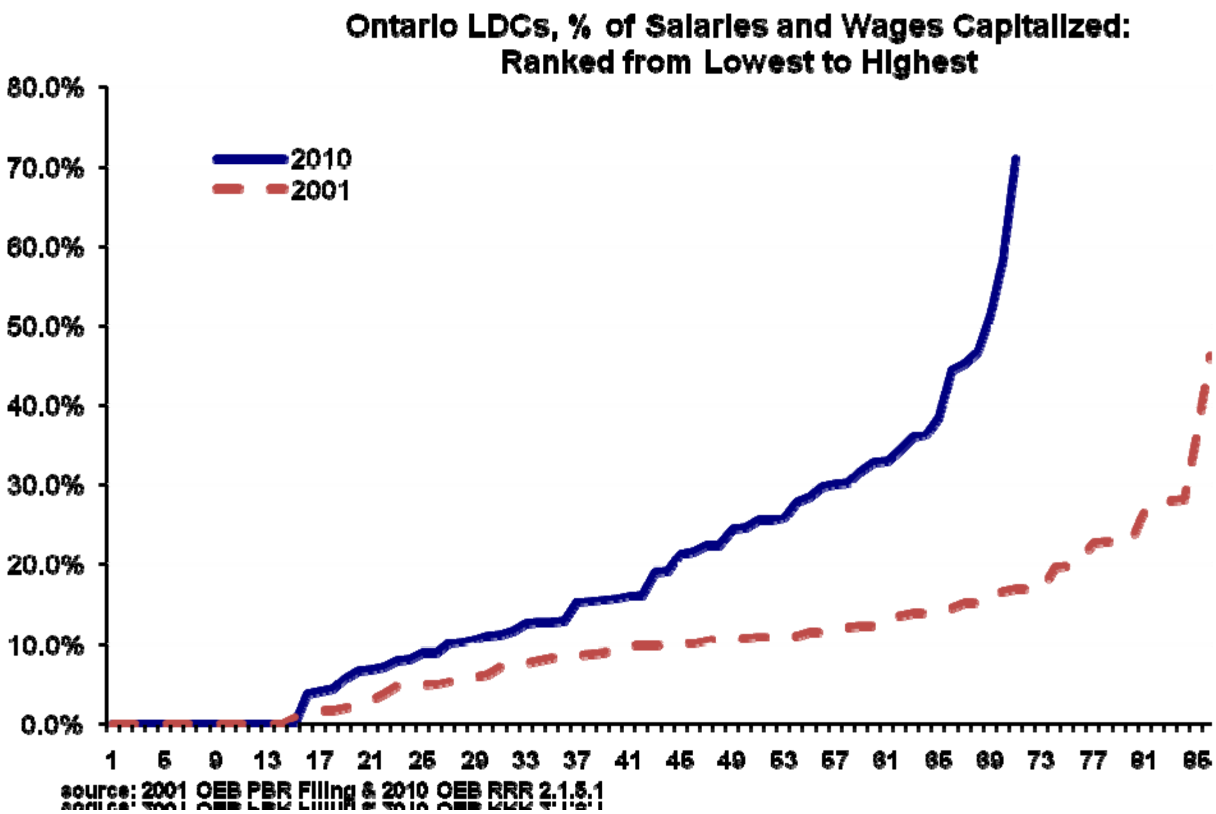
Let's examine the impact that the IR had on LDC's accounting shifts. Exhibit 2 presents the data for 2001 and 2010. What can we conclude about the percent of labour capitalized by Ontario LDCs over the past decade:

- in 2001 the average rate was 10 percent with a maximum of 46.2;
- in 2010 the average rate was 34.4 percent with a maximum of 71 percent;
- in 2001 there were 6 LDCs with rates above 25 percent;
- in 2010 there were 20 LDCs with averages above 25 percent;
- in 2001 there were 2 LDCs with rates above 30 percent;
- in 2010 there were 13 LDCs with rates above 30 percent;
- in 2010 there were 6 LDCs with rates at or above the 2001 maximum.

So, we can conclude that a massive shift occurred between 2001 and 2010 in labour capitalization among Ontario LDCs. The average increase was 228 percent. That is, over the past decade labour capitalization rates more than tripled.

Furthermore, it was not just labour that increased. The proportion of "overhead" also increased. In 2001, the share of capital comprised of overhead equaled 8 percent. By 2010, the share of capital comprised of overhead equaled 12 percent. Since the size of capital additions was higher in 2010, the increase in the amount of "overhead" being capitalized was significantly higher than 50 percent.

Exhibit 2.



3.2.2 Consequences of Cost Shifting for Rate Payers, Rates, Profits and Shareholders

All together, we might find that hundreds of millions of dollar per year have been shifted from expenses and capitalized. Possibly billions of dollars cumulatively. This would indeed be a troubling conclusion for its ominous implications discussed in section 2.2.3.

3.2.3 Additional Troubling Conclusions

Numerous other factors are also very troubling and follow directly from the Board's perverse incentive scheme.

- The share of capital additions comprised of equipment is now seemingly quite low for some LDCs. The data filed by the LDCs with the Board indicates that for some LDCs, equipment as a share of capital additions is below 30 percent.

- With the marked changes in the composition of capital additions (e.g., more labour, more overhead), a given dollar expenditure in 2010 even if adjusted for inflation will not be comparable with historical capital expenditures. **Each dollar of capital additions is now putting in less hardware and more labour or overhead.**

- **Since each dollar of capital additions is 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.**
- Since LDCs are now capitalizing costs that used to be expensed, future returns will be higher as the rate base grows faster than it would have without the marked shift from O&M costs into capital costs.

- Since LDCs are now capitalizing costs that used to be expensed, future rates will be higher as the rate base grows faster than it would have without the shift from O&M costs into capital costs. In some cases, rates may be notably impacted.

- Since LDCs are now capitalizing costs that used to be expensed, future rates will also be higher to pay for the increased returns as the rate base grows faster than it would have without the shift from O&M costs into capital costs. **Customers could be paying $80-90 million per year more in higher rates.**
- Historically, a subset of Ontario LDC's had responded to the contributed capital policies and overcapitalized their networks. These LDCs were allocatively inefficient. The Board's incentive schemes will exacerbate the existing inefficiency and lead to rates that are higher than they would have been if more optimal factor input mixes had been pursued.

Unfortunately, these negative implications for biased capital additions, inflated earnings, higher rates, and greater allocative inefficiency have been accumulating for some time.

3.3 Evaluating Line Loss Performance among Selected Canadian LDCs

3.3.1 Need for Optimization

Given the pervasive green implications of unnecessary energy usage, not to mention the costs to customers, it is essential that distributors' line losses are optimized. OFGEM reported its own research that found utilities were not factoring in line loss considerations when making operating decisions.[12]

3.3.2 Utilities' Prior Responses to Price and Cost Incentives

Our prior research found that over the 1988-1993 period, improvements in line losses helped offset a notable increase in capital usage among many of Ontario's distribution utilities.[13] Losses averaged about 12–15 per cent of costs and many utilities respond aggressively to the 40 per cent increase in wholesale commodity prices by reducing kWh losses per customer by 27.6 per cent. Following the rate freeze, over the 1993-1997 period line losses continued to improve as utilities responded to their altered cost incentives. By 1997, a substantial number of utilities had made significant improvements in losses.

3.3.3 Current Losses and Extent of Degradation

Unfortunately, however, more recently, the treatment of line losses has been altered. What are the consequences of these altered incentives? By 2009, we find widespread and substantial degradation in line losses among Ontario LDCs. For some LDCs, the degradation is over 40 percent. On a customer-weighted basis, we find losses have degraded almost 33 percent relative to the 1995-1997 period. On a simple average basis, losses have degraded almost 20 percent.

3.3.4 Losses in Alberta and Ontario

How do current Ontario losses compare with LDCs in Alberta? As Exhibit 3 indicates, we find that the Alberta LDCs have lower losses compared with Ontario LDCs. EDTI's line loss rate of 2.64 percent is lower than all nine large Ontario LDCs examined. Ontario loss rates run from

[12] OFGEM, *Electricity distribution losses, A consultation document*, January 2003, 03/03

[13] F. Cronin and S. Motluk, "AGENCY COSTS OF THIRD-PARTY FINANCING AND THE EFFECTS OF REGULATORY CHANGE ON UTILITY COSTS AND FACTOR CHOICES," *Annals of Public and Cooperative Economics* 78:4 2007 pp. 537–565.

2.65 percent to just above 4. The average line loss in Ontario is 3.33 percent. EPC's line loss rate is 3.02 over this period but subsequently fell to 2.83 with the implementation of its Line Loss Incentive Agreement.

I might also note that Alberta's nearly 22 percent advantage in its LDCs' line losses compared with Ontario's LDCs' losses is almost exactly the size of the degradation experienced among Ontario LDCs compared with their 1995 to 1997 performance. Let's put some monetary values around the line loss degradation in Ontario; i.e., what does this cost customers currently and say over the next 5 years. First, let's examine EPC's Line Loss incentive Agreement for any insight it might provide for stakeholders in Ontario.

Exhibit 3. Line Losses: Alberta and Selected Ontario LDCs

	Urban Average	**Low Density**
Alberta	2.73-2.83	4.06 to 4.95
Ontario	3.33	6.85 to 8.55
Percent	+15.0 to 22.0%	

3.3.5 The EPC Line Loss Incentive Agreement

Despite EPC's loss rate of 3.02 percent, the company entered into an agreement with stakeholders intended as an incentive under its' Formula Based Ratemaking. By 2010, EPC's rate fell to 2.83 percent. Shareholders and customers had a gross savings of $1.772 million in the first two years of the Agreement. And, pursuant to the Line Loss Agreement, in 2009 and 2010, EPC returned $0.886 million to its consumers as their share of the utility's improved losses; it also retained $0.886 million as its share.

The low-density Alberta LDCs compare favourably as well. AE's line loss is 4.06 percent and FAI's is 4.95 percent. Two Ontario LDCs we can use as benchmarks are Hydro One and Algoma Power formerly GLP. Hydro One's line loss is 6.85; Algoma's line loss is 8.55. Clearly, the Alberta LDCs have superior results.[14]

[14] Part of the differential between Alberta and Ontario could be due to the definition of distribution versus transmission employed in the two jurisdictions.

3.3.6 Line Loss Degradation Consequences for Customers

Above we examined how the current Ontario loss rates compare with earlier periods. We used the data filed with the OEB in the 1st Generation process as well as the data filed with the Board starting in 2000 and running through 2010. Recall, compared to 1995 to 1997 (i.e., during the rate freeze), we find that the customer-weighted average loss rate over 2007 to 2009 has increased by nearly 32 percent; nearly 20 percent unweighted. (Note, again that the latter is very close to the 22 percent advantage of the Alberta LDCs line losses compared to Ontario LDCs line losses). Aggregating across Ontario LDCs, the degradation in losses exceeds $86 million in 2010. The value of these losses exceeds the power supplied to Greater Sudbury Hydro by about 10 percent. Per customer, the increased losses currently cost about $18 a year. For some customers of particular LDCs the yearly loss is over $32.

Assuming no further degradation in losses since 2009 by Ontario LDCs and that power costs average $.10, over the next 5-year period the increase in power losses would equal about $541 million, or about $113 per customer. Power costs at $.11 would bump these figures to $595 million and $124 per customer. Any degradation beyond what we factored in for the 2007 to 2009 period would of course raise these numbers proportionately. See Exhibit 4.

Exhibit 4. Aggregate and Per Customer Costs of Line Loss Degradation

	2010 Line Loss Degradation Costs	**5-Year Degradation Costs @ $.10 Power**	**5-Year Degradation Costs @ $.11 Power**
Aggregate	$86,000,000	$541,000,000	$595,000,000
Per Customer	$18	$113	$124

What about the customers of LDCs whose losses have degraded above the average? For customers of high degradation (i.e., customer weighted average increase of 32 percent) LDCs the cumulative loss costs over the next 5 years would be $155 at $.10; at $.11 the cumulative costs are $171.

3.4 Evaluating Rates and Reliability Performance among Selected Canadian and US LDCs

There is reliability degradation over the 2006-2010 period compared with 2000-2005. There is even more pronounced degradation over the 2006-2010 period compared with 1993/4 to 1997/98.[15] As shown here Alberta high density LDCs' reliability is comparable to the 1993/4 to 1997/98 Ontario performance and notably better than the 2006-2010 Ontario performance. Both Alberta and Ontario LDCs tend to have better reliability performance than a set of Northern US LDCs while the Alberta and Ontario LDCs rates are also lower than the set of Northern US LDCs.

Exhibit 5 displays rate/monthly charges and reliability data for 10 large urban Ontario LDCs, two Alberta LDCs (EPC and EDTI), together with and 8 northern U.S. LDCs.[16] As we can see, including local access charges the Alberta LDCs lie about mid-point among the selected Ontario LDCs. Compared with the U.S. LDCs' rates, the Canadian rates are substantially lower than the U.S. average of $45.36 and in some instances about half the distribution rates of a number of U.S. LDCs including the old Niagara Mohawk, PECO, and NSTAR (Boston).

In terms of reliability, Alberta LDCs rank 1st and 4th out of the 22 examined; Ontario LDCs rank 2nd, 3rd, and 5th through 14th. The selected Ontario LDCs' average SAIDI is almost twice as high as Alberta's (1.43 versus 0.74). **Compared with the U.S. LDCs' reliability, the Alberta LDCs' average is 77.4 percent better than the U.S. average of 3.25 hours per year; Ontario LDCs' average is 44 percent better than the US average.**

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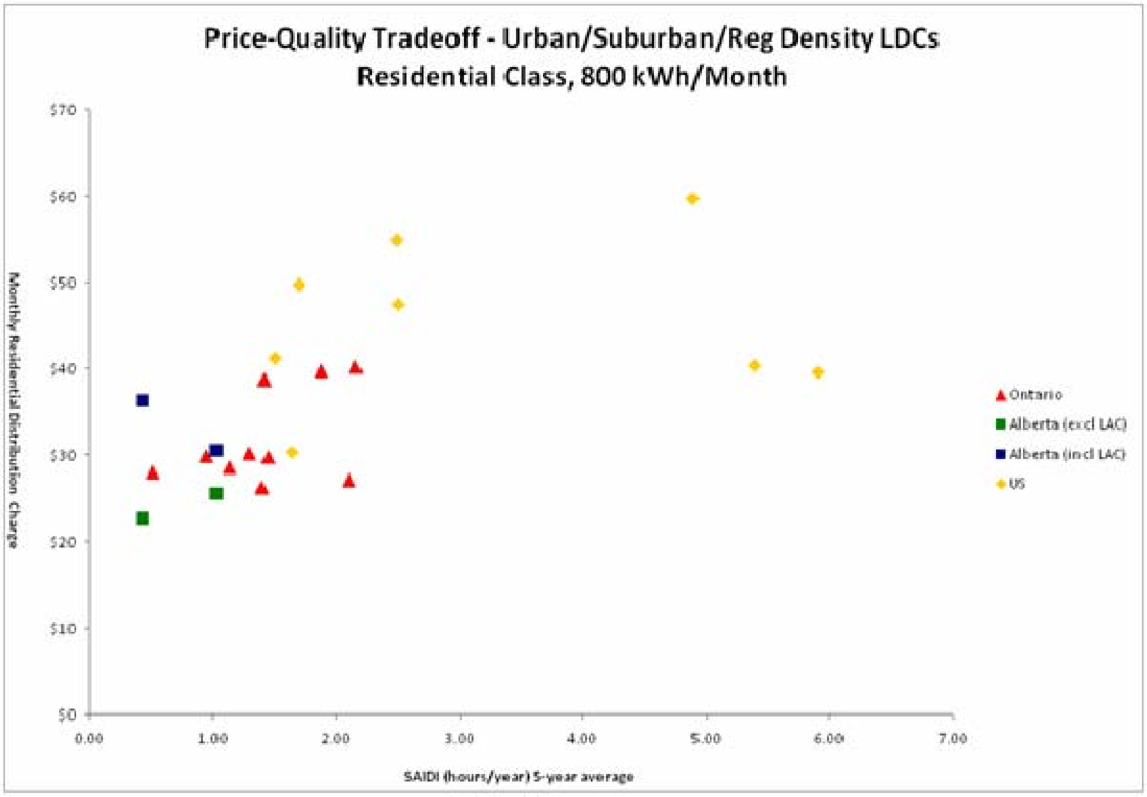
[15] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[16] Rates are published distribution charges plus billing and collecting costs for residential customers consuming 800 kWh per month. They do not included flow through items, debt repayment, riders, conservation, green charges, or transmission costs. Transmission charges are a bit higher in Alberta than Ontario; including such costs in the comparison would tend to lower the difference between Alberta and Ontario LDCs. Average consumption in Alberta is lower than Ontario; calculations at lower consumption levels, say 600 kWh, would tend to increase the differences between Alberta and Ontario LDCs.

Exhibit 5. Rates & Reliability for Higher Density Alberta, Ontario, and U.S. LDCs



3.4.1 Comparison to Pre-IR Periods

How do the current Alberta and Ontario reliability performances compare with Ontario's historical performance? Exhibit 6 presents the 3 and 5-year average for municipal distributors over the 1993 – 1998 period. Note the Alberta LDCs' performance of 0.43 and 1.04 hours of outage per year would have placed Alberta utilities in the 2nd Quartile among Ontario utilities during the mid-late 1990s.

Exhibit 6. Service Reliability Pre-Restructuring for Ontario Municipal Distributors*

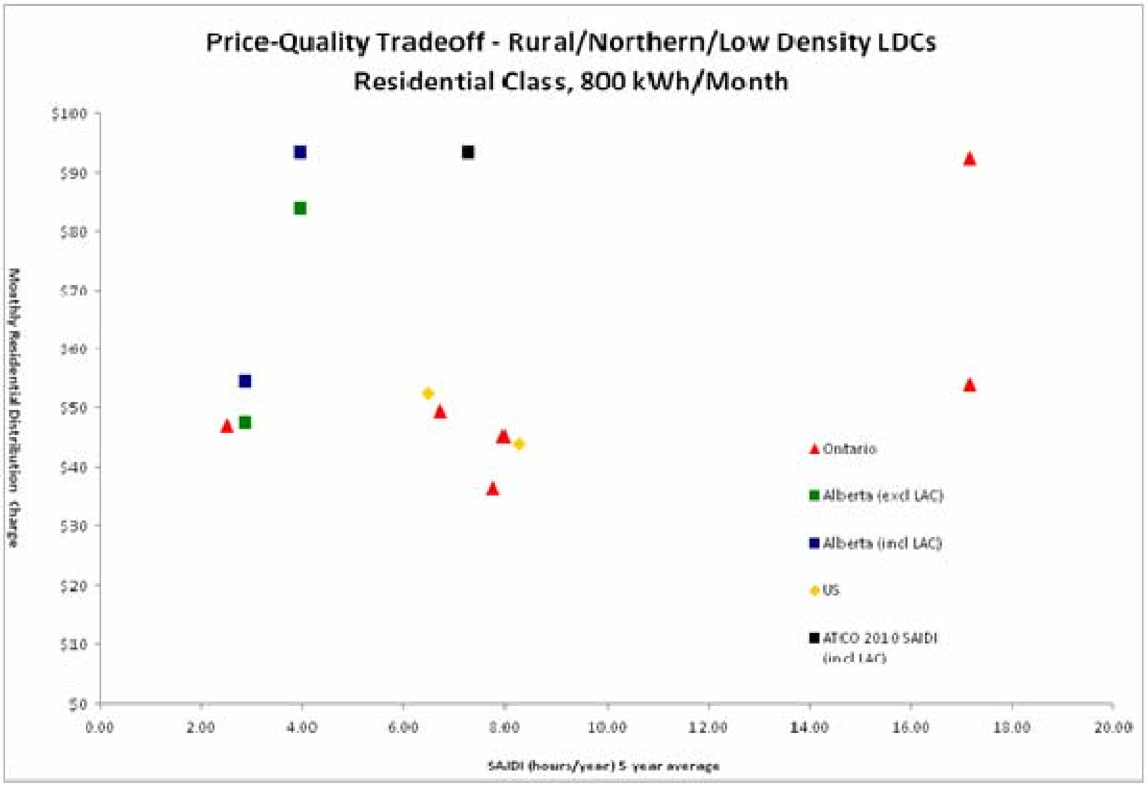
	3-Year Average	**5-Year Average**
SAIDI		
Mean	1.23	1.20
Top Quartile	0.32	0.42
SAIFI		
Mean	1.49	1.51
Top Quartile	0.34	0.54

***Performance Management Ratios 1993 – 1998 Composite Results*, MEA, August, 1998**

Exhibit 7 displays rate/charge and reliability data for 6 low or very low density Ontario LDCs, two low-density Alberta LDCs (FAI and AE), together with 2 northern U.S. LDCs operating in Maine. As you can see, including local access charges the Alberta LDCs charges are nearly identical with Hydro One low and medium density rates. However, Alberta low density reliability is better than Ontario reliability even with the discontinuity in 2010.[17] FAI's higher density SAIDI of 2.9 hours per year is notably better than all but one of the Ontario LDCs whose SAIDI's range from 7.8 to 17.2 hours.

[17] We would note that AE has reported that its reliability data has a discontinuity in 2010 versus earlier years. "Note 1: Implementation of ATCO Electric's Outage Management System during 2009 significantly changed the data collection process and resulted in a discontinuity of reliability data measurement after the end of 2009." Despite this increase, however, AE still compares favorably with Hydro One which recorded a SAIDI of 9.37 in 2010 versus 7.27 for AE.

Exhibit 7. Rates & Reliability for Lower Density Alberta, Ontario, and U.S. LDCs



Canadian urban LDCs have rates that are substantially lower than the U.S. LDCs. Of the 8 higher density U.S. LDCs examined, only 2 LDCs have rates in the $30s per month, 4 LDCs are in the $40s per month, and 2 LDCs are in the $50 per month. National Grid (MA) has the lowest US rate.

The reliability comparison is possibly even worse for the US utilities: EPC's SAIDI is .43 while EDTI is 1.04; the Ontario average is 1.4. Only 3 of the U.S. LDCs have SAIDIs less than 2 hours per year and they range from 1.5 to 1.7, with National Grid (MA) having the 2nd lowest SAIDI after Duquesne (Pittsburgh). NSTAR (MA) has the third lowest.

The remaining 7 U.S. LDCs range from 2.5 to 5.9 hours of outage per year. Exhibit 8 examines the data underlying the Canadian-U.S. LDC comparison.

Exhibit 8. Canadian Performance Comparisons to U.S. Northern LDCs

	Distribution Rate[a]	Annual SAIDI[b]
EPC	36.30	0.4
EDTI	30.42	1.0
Ontario Avg.	31.80 (26.22 - 40.10)	1.4 (0.51 - 2.2)
Detroit Edison	39.56	5.9
PECO (Phil)	54.93	2.5
Duquesne (Pitts)	41.18	1.5
NYSEG	40.32	5.4
Rochester G&E	47.33	2.5
Nat Grid NY	59.65	4.9
Nat Grid MA	30.26	1.6
NSTAR (Boston)	49.68	1.7

Author calculations.
[a] 2011 distribution rates assuming 800 kWh per month. Includes LAC.
[b] For SAIDI 5 year average, 2005-2009, hours per year.

3.5 Evaluating the Biases and Perverse Incentives of O&M Benchmarking

In 2008, we discussed the issue of partial cost benchmarking in general and labour capitalization in particular. We discussed the widely varying labour capitalization among Ontario LDCs, the errors associated with O&M benchmarking, and the perverse incentives engendered by such a framework. We stated that a high probability existed that LDCs would respond to the Board's 3rd Generation IR by making accounting adjustments, i.e., moving costs from O&M to capital.

We also stated that the "efficiency" rankings associated with O&M expenses were random, biased and bore no relationship to an LDC's total costs of distribution including capital. As the OEB's 1999 Staff Report demonstrated, in a 3-factor cost structure of capital, labour and materials, capital's share is about 50 percent.

Exhibit 9 presents the 1993 weights for the typical utility for both the three and four-factor cases. Typical weights by size class are also shown. On average, about 45 percent of a typical utility's total cost is related to capital. Remaining cost shares are 29 percent for labour, 13 for material and 13 for line losses. Medium sized utilities tend to have a slightly higher share for capital and slightly lower shares for labour and material. In the three-factor case the cost shares are 52 percent for capital, 34 percent for labour, and 15 for materials.[12]

Exhibit 9. Capital-Labour Cost Shares for Ontario Utilities

Table 4.4

1993 Average Weights for Cost Shares									
	Four Factor					Three Factor			
Simple Average	Capital	Line Loss	Labor	Materials	Total	Capital	Labor	Materials	Total
Large	0.45	0.12	0.30	0.13	1.00	0.51	0.34	0.14	1.00
Mid	0.49	0.12	0.28	0.12	1.00	0.55	0.31	0.13	1.00
Small	0.40	0.16	0.30	0.14	1.00	0.48	0.35	0.17	1.00
All Utilities	0.45	0.13	0.29	0.13	1.00	0.52	0.34	0.15	1.00

As we recommended in 2008:

> Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labor burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labor can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we cannot assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labor capitalization rate.

3.6 Ranking Errors Comparing Ontario LDCs on OM&A rather than Total Cost

So far we have examined the biases involved with OM&A benchmarking. But how different are the rankings for individual LDCs? The exhibit below does just that for a large set of 23 of the 48 LDCs used in the 1st Generation staff report. For each of these LDCs we have their OM&A, total costs, and their respective ranking across the 48 firms. As we can see, the rankings are markedly different. Utility 1, which ranks 3rd on OM&A, ranks 43rd on total costs. Many others

[12] These weights are generally consistent with weights reported from utilities in other jurisdictions.

are just like that: low ranks on total costs but high ranks on OM&A. Others are just the opposite. Utility 18 ranks 37th on OM&A and 3rd on total costs. Many others are similarly ranked: low ranks on total costs but high ranks on OM&A. What we see in this exhibit with actual LDC cost and cost rankings is the perverse effect of rewarding low OM&A/high total costs and penalizing high OM&A/low total costs when we benchmark on partial costs.

Exhibit 10. Comparing LDC Rankings on OM&A vs. Total Costs

Utility	OM&A Ranking	Total Cost Ranking	Difference in Rankings	Percent Difference in Ranking
1	3	43	-40	-0.83
2	7	30	-23	-0.48
3	8	24	-16	-0.33
4	10	35	-25	-0.52
5	11	33	-22	-0.46
6	12	39	-27	-0.56
7	15	45	-30	-0.63
8	18	11	7	0.15
9	20	6	14	0.29
10	21	7	14	0.29
11	22	10	12	0.25
12	24	41	-17	-0.35
13	25	42	-17	-0.35
14	28	46	-18	-0.38
15	31	47	-16	-0.33
16	31	47	-16	-0.33
17	33	9	24	0.50
18	37	3	34	0.71
19	38	18	20	0.42
20	42	23	19	0.40
21	45	14	31	0.65
22	46	21	25	0.52
23	47	25	22	0.46

In assessing the OEB's data for 2010, we find the same randomness regarding the efficiency rankings. In 2010, LDCs which the Board ranks as efficient based on O&M costs are actually at the bottom of the total cost rankings (i.e., costs with capital included). Similarly, LDCs which the Board ranks as inefficient based on O&M costs are actually among the most efficient based on total costs (i.e., costs with capital included).

Due to these inequities on rankings and perverse associated incentives the OEB should end its IR on O&M. The OEB should move to incorporate the decades of capital data that was specifically collected from the LDCs (capital back to the 1970s) into a total cost assessment. Furthermore, the benchmarking should include line losses as well as reliability. Reliability performance should incorporate the LDC's own performance (e.g., SAIDI) as well as the valuations that customers attach to interruptions. Customer valuations for interruptions can be determined through such contingent market methodologies as willingness to pay surveys.

Appendix A

Cronin Recommendations in the OEB's Cost Comparison and 3rd Generation Proceedings

During the OEB's 2007 and 2008 proceedings on Distributors' Cost Comparison and 3rd Generation IR for electricity distributors, I offered a number of recommendations to assist the Board to structure a more effective, efficient, and equitable IR framework.[18] These recommendations covered a wide range of issues fundamental to properly establishing an incentive scheme for the LDCs, their shareholders and their customers. These issues included:

- the appropriate form of benchmarking,
- the flaws, biases and perverse incentives with O&M regulation,
- the critical problems with labour capitalization and LDCs' cost shifting,
- the importance of appropriate incentives for line losses,
- the need for service quality regulation (SQR)
- the need to implement single customer guarantees, and
- the need to implement an IR which targets a socially optimal level of reliability.

Some of my specific recommendations included:

[18] See for example, Comments by Francis J. Cronin, In the matter of the Ontario Energy Board's 3rd Generation Incentive Regulation for Electricity Distributors (EB-2007-0673), On behalf of Power Workers' Union, April 14, 2008.

1. **Need to Reflect Integrated Nature of Electric Distribution Operations.** The most important, overriding issue in the Board's evolving benchmarking is the failure to "model or benchmark" the integrated operation of distribution utilities with comprehensive data reflecting:

    - the joint nature of LDC output
    - the substitution relationships among an LDC's inputs

    Joint output means that just and reasonable rates cannot be determined unless costs are assessed jointly with reliability and service quality; failure to reflect all LDC outputs seriously biases the assessments in favour of LDCs with lower reliability. Input substitution with varying allocations makes meaningless an examination of one input in isolation from the rest.

2. **OM&A benchmarking is inherently flawed.** It fails to recognize the integrated nature of utility operations and that LDCs can and do make management decisions regarding the appropriate distribution of their budgets between O&M and capital. Based on a sample of 2000 data filed with the OEB we find: (1) the share of labour capitalized ranges from less than 10 percent to 50 percent (2) the resulting capitalized labour represents as much as 39 percent of reported OM&A and as little as 7 percent (3) the amount of capitalized labour per customer reported to the Board is inversely related to the amount of OM&A per customer reported to the Board (4) finally, conclusions about cost rankings and comparisons change when the capitalized labour per customer is added to the amount of OM&A per customer. This means that OM&A benchmarking is inherently flawed.

3. **IR, Cost Incentives, and SQR.** It is clear that IR produces incentives for potentially imprudent cost cutting. We also know from empirical research that LDCs under IR but without standards and penalties do in fact cut O&M adversely to maximize profit. Service quality/reliability must be included in any IR framework as a benchmark to assess a utility's production, integrating utility cost benchmarking with service quality and reliability regulation.

4. **Reliability Costs and Observed "Inefficiency."** Therefore, since reliability varies so "widely" among LDCs, and those LDCs with higher reliability will generally have higher costs, we must structure the LDC benchmarking to account for these differences. If not, and such different cost causation situations are simply observed through the LDCs' OM&A costs, we may mistakenly identify "higher cost" LDCs as less efficient than lower cost LDCs providing lower reliability. If this is so, the benchmarking approach proposed by PEG and Board staff will penalize the high-reliability LDCs and reward the low-reliability LDCs.[19]

5. **European SQR Efforts.** European regulators have led the way and laid out compelling arguments for the need to blunt the adverse impacts of IR on service quality. CEER has outlined the components of such SQR and encouraged its member jurisdictions to implement these items, such as data collection and customer surveys, system-wide standards, and single customer guarantees. Individual European countries have incorporated WTP and interruption costs into their IR frameworks. The Board should thoroughly review this experience for its applicability to Ontario and implementation into a robust set of service reliability mandates with incentives/penalties.

[19] We are using the terms "high" and "low" in a relative context.