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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 – Distribution Network Investment Planning (EB-2010-0377) and Regulatory Framework for Regional Planning for Electricity Infrastructure (EB-2011-0043)

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 Distribution Network Investment Planning (EB-2010-0377) and Regulatory Framework for Regional Planning for Electricity Infrastructure (EB-2011-0043).

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

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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, two of which pertain to planning: Distribution *Network Investment Planning (EB-2010-0377)* ("Investment Planning"); and, *Regulatory Framework for Regional Planning for Electricity Infrastructure (EB-2011-0043)* ("Regional Planning"). On November 8, 2011 the OEB released the following staff discussion papers: *Distribution Network Investment Planning* ("Investment Planning Discussion Paper"); and, *Regulatory Framework or Regional Planning of Electricity Infrastructure* ("Regional Planning Discussion Paper"). Along with the Investment Planning Discussion Paper, the Board issued a prototype spreadsheet model ("PA Model") and report prepared by Power Advisory LLC ("PA Report"). The model is intended to help assess the practical feasibility of estimating the impact of both the amount and pacing of a distributor's proposed investments on customer bills.

The Investment Planning Discussion Paper states that the objective of the Investment Planning initiative is "to ensure that electricity distributor network investment plans ("network plans") are demonstrably economically efficient and cost-effective, and paced so as to match required expenditures with fair and reasonable rate adjustments and predictable changes to the elements of customer bills affected by the plans".

The Regional Planning Discussion Paper states that the purpose of the Regional Planning initiative is to develop a regulatory framework for regional planning that is consistent with the principles articulated in Transmission System Code ("TSC") consultations as well as the following principles:

- **that an optimized solution is desirable as being the lowest cost in the long term;**
- **that a coordinated solution is desirable as allowing for a consideration of broader needs and for involvement by a larger set of stakeholders; and**
- **that cost responsibility for optimized solutions is attributed in an appropriate manner.**

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.**

In this section the PWU's overarching views on a RRFE are provided in the responses to the issues set out for comment in Attachment A to the Board's April 5, 2012 letter related to vision and context, and "Other" issues. The PWU's comments and views on Investment Planning and Regional Planning in the remaining sections are provided in the context of the PWU's RRFE vision and context.

Vision and Context

2.1 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.

2.2 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 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 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.

2.3 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 their 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 ("IR") 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.

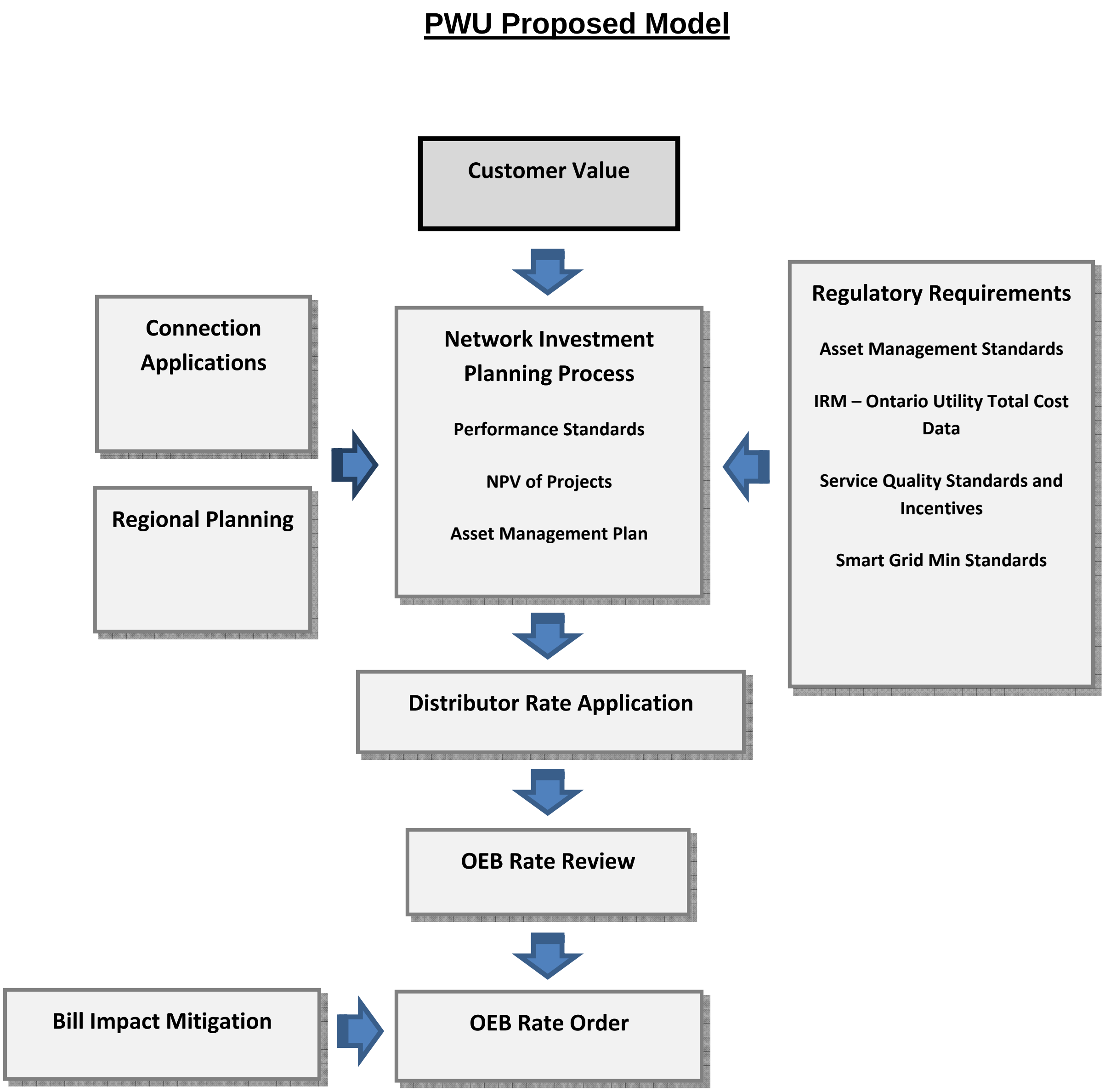
Change: Ex-ante added. Changes in all charges considered.

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 viable 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:



Other

2.4 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.

2.5 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.

3. Investment Planning and Regional Planning Issues

3.1 How do we optimize planning across the sector to ensure that investment decisions achieve the level of reliability and quality of supply that consumers demand and are paying for?

In pursuing the optimization of planning across the sector, the efficient and cost effective investment planning at the individual utility level must first be addressed. In doing so the Board needs to recognize the need to address the following issues:

- Regulatory uncertainty;
- The significant capital investments required to replace aging assets;
- The need to replace an aging workforce;
- The need to incorporate service quality standards that meet customer value and expectations in network investment planning;
- The inappropriateness of the total bill impact as a key driver of network investment planning; and,
- Board Asset Management Standards to expedite the regulatory review of utility investment plans.

3.1.1 Regulatory Uncertainty

The Board's current regulatory framework fails to provide the regulatory certainty required for efficient network investment planning that ensures the sustainability of service quality performance. Not only are outcomes of cost of service reviews unpredictable, regulatory risk is also created by the inappropriate indices/benchmarking in 3rd Generation IRM including: the use of a macroeconomic price index instead of the Ontario distribution industry Input Price Index; Total Factor Productivity based on U.S. utility database instead of Ontario distributors' data; benchmarking based on partial costs instead of total cost and that does not factor in service quality performance (see the PWU's submission on the Board's RRFE initiative on *Defining and Measuring Performance of Distributors and Transmitters, EB-2010-0379*).

Distributors are not able to easily ramp their workforces and fleet requirements up and down, or contract for work, to meet significantly different work plan volumes from year to year that are a result of uncertainty as to whether work plans will be approved or not. Planning work has to take place well in advance of the year in which the work is to be undertaken. Making arrangements for incremental labour and fleet arrangements to accommodate significantly more work takes time. Where there is regulatory uncertainty a utility may hold back on making the arrangements. As a result when a project is approved there is the likelihood that the utility will not be ready to 'hit the road running' in the year and at the time intended. This could result in under-expenditure of approved costs. In turn under-expenditure can result in increased uncertainty in the subsequent rate proceeding.

3.1.2 Aging Assets

The PWU submits that the current regulatory treatment of capital investment under both the cost of service and IR regimes fails to recognize the significant capital investments required to replace aging assets. To ensure the sustainability of the distribution systems it is essential for the OEB to recognize the need for distributors to replace aging assets at an increased rate and to adopt a long-term view of capital investments.

Ofgem has done so. 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 will need to spend to maintain service quality performance. Most of the RECs' forecasts indicated the need to increase capital investments with the scope of the required increases varying widely.[1] In recognizing the need for the increased capital investments

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

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 unfortunate fact is that expensive Government policy initiatives are being launched at a time when an under-funded and aging network infrastructure requires unprecedented levels of capital investment over the foreseeable future. As a result utilities' rates have been under inordinate pressure while the population of assets that should be replaced grows.

Recent cost of service rate applications such as those filed by Hydro One and Toronto Hydro indicate that unless the distributors significantly increase their level of sustaining work now and into the future, the systems will be left with a population of assets that is too old and in such poor condition that it will not be possible to replace these assets quickly enough to avoid catastrophic outcomes.

In its presentation at the March 28-30, 2012 RRFE consultation the Distribution Regulation Review Task-Force[2] ("DRRTF") stressed that the issue of capital investment is perhaps the most pressing issue in the sector and expressed concern on the considerable uncertainty on how the current Incremental Capital Module ("ICM") is to be applied. The DRRTF calls for an expeditious review of the regulatory treatment of capital investments to be completed in time for rate applications filed in 2012 for implementation in the 2013 rate year.[3] The PWU supports the recommendations of the DRRTF. The magnitude of this problem is such that it cannot be put off to the future. Delay will inevitably make the implementation of a solution a practical impossibility as the remaining time available to end of life of the aging assets will be inadequate to accomplish the tasks necessary to avoid unacceptably serious declines in service quality. Delays result in future ratepayers burdened with a disproportionate share of

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[2] The DRRTF represents the Coalition of Large Distributors, Enbridge Gas Distribution Inc., Hydro One Networks, and Union Gas Limited.

[3] 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

these costs. Distribution network investment planning should not result in these outcomes.

Regulatory review of capital investments should go beyond a single test year. Multiple-year capital programs would reflect the Network Investment Planning horizon and better address the issue of replacing aging assets. In addition approval of multi-year capital programs would mitigate regulatory risk that impedes efficient planning.

3.1.3 Aging workforce

According to a 2011 Electricity Sector Council report entitled *Recharging our Workforce, A Strategic Framework For Industry Action,*[4] 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 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.

[4] http://www.brightfutures.ca/Training/english/report/RechargingOurWorkforce_Report_e.pdf

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

3.1.4 Service Quality Standards

The PWU submits that distribution network investment planning must respond to service quality standards that reflect customer value and expectations established through customer WTP surveys.

While distributors' network investment plans take into account equipment failure the Board does not have incentives in place for service quality performance that would compel the utilities to include service quality standards in their strategic objectives to guide network investment planning. Such incentives would ingrain the service standards throughout the company and in all its processes. Conceptually a utility would achieve this by, as a first step, including reliability as a key business value with the service reliability metrics as the corresponding key performance indicators in its prioritization process. Multi-criteria analysis would then be used to prioritize investments by measuring their risk impact on the business values, including reliability.

Basing the standards on customer WTP surveys would provide for investment levels that are in-line with customer value and expectations. 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.[5]

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[5] 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

3.1.5 Total Bill Impact

The Investment Planning Discussion Paper's proposal to make total bill impact an important consideration in distribution network investment planning is inappropriate. The PWU has no issue with the gathering of data and reporting on the direct and indirect bill impacts of distribution network investments including those required to accommodate renewable energy generation ("REG") connections for information purpose. The PWU, however, does not agree with any misleading implication that the Global Adjustment and Regulatory Charges are in the control of a distributor and the result of a distributor's decision.

The fact is that distributors do consider bill impact in their planning process, including the prioritization of investments. Typically, the prioritization process results in a portfolio of individual investments across all work categories that together make up a utility's preliminary Investment Plan. The preliminary Investment Plan is then reviewed by Senior Management who may further modify it based on consideration of the impact on customer rates, the ability to accomplish all of the proposed work in light of known constraints (e.g. labour, material, engineering resources), the financial health of the company, and the impact of changes in investment levels on residual risk to business objectives. The end result of this process is a prioritized Investment Plan proposal that effectively meets the distributor's business objectives and represents a balance among customer and distribution system needs, costs, and risks. The proposed Investment Plan is then recommended to the company's Board of Directors for approval. It is therefore clear that distributors do consider bill impact related to factors in their control. To require distributors to consider total bill impact resulting from factors beyond their control not only places additional work load on distributors but also puts pressure on their planning process and investment decisions potentially resulting in sub-standard investments.

The PWU submits that at the centre of this issue is a lack of clarity with respect to the Board's mandate. The PWU recognizes that the Board, by virtue of its jurisdiction and mandate, is confronted by a number of competing objectives in discharging its duties and therefore the Board's desire to be informed of total bill impacts and to require distributors to consider total bill impact in their planning process is understandable. The concern is in the manner and extent to which the Board might employ such information in its review of an individual rate application and the implication on the service quality of a distributor that is pressured to modify its planning process out of concern of total bill impact.

Under the Board's various filing requirements, distributors are already providing the necessary information required to determine reasonableness of costs. To require distributors to include aspects of total bill impact that are beyond their control in their investment planning process, or to disapprove proposed work plans based on their 'total bill impact' would raise questions about the Board's jurisdiction and mandate. The Board should not attempt to control prices that it has no jurisdiction over (e.g. electricity from wind) through its jurisdiction over distribution and transmission rates.

While the PWU is sympathetic with the increases in total electricity bills that consumers have and will face related to the various bill components, the PWU submits that it would be fundamentally wrong for the Board to seek to address total bill impact largely related to non-distribution cost components be it through network investment planning or in approving revenue requirement. Where the issue is total bill impact related to a utility's costs, the Board has at its disposal mechanisms to mitigate, *ex-post*, rate impacts that are attributable to decisions that are in the control of distributors that precludes the need for *ex-ante* mitigation that would compromise the efficiency of network planning and compromise the system's sustainability and service quality performance.

3.1.6 Board Asset Management Standards

The Investment Planning Discussion Paper makes reference to KPMG's and KEMA's reports on asset management, and Figure 1 of the Investment Planning Discussion Paper, Distribution Network Planning – Current Regulatory Framework, includes asset management in the framework. These references articulate the importance of robust, comprehensive asset management standards to efficiently plan the distribution business which has such an intensity of physical assets.

In its 2009 review prepared for the Board, KPMG makes reference to PAS 55, a standard that Ofgem implicitly applies in its review of utilities' rate applications.[6] KPMG also developed a maturity model as a framework for evaluating and describing the state of asset management practices at Ontario distributors. KEMA discusses the PAS 55, as well as other "local" standards in its review prepared for the OEB.

However, the PWU notes that the Investment Planning Discussion Paper does not explicitly identify the possibility of the Board establishing a regulatory Asset Management Standard. In the PWU's view, establishing regulatory standards for asset management will facilitate the review of utilities' rate applications by providing the opportunity for expedited reviews. A utility could qualify for an expedited review through a Board established utility self-certification process for compliance with the Board's Asset Management Standard.

In considering a regulatory Asset Management Standard, the RRFE would need to recognize that there will be the need to differentiate amongst distributors given the vast differences in utility size in Ontario. Hydro One's needs would be very different from those of the smallest utilities in terms of complexity and economies of scale. To accommodate utility differences, a two-tiered or multiple-tiered approach should be considered.

Further, any Asset Management Standard considered must be big on integration and more than a standalone asset management application since the scope of the standard would be enterprise-wide and touch upon many other assets and processes including financial assets, human assets, and information assets. This will lead to a culture change for the distributors that will make the company more inter-linked. The RRFE

[6] KEMA. Approaches to Regulatory Assessment of Network Utility Investment Plans. November 2009. http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Report_Asset_Mgmt_Investment_Plans_20091218.pdf

therefore needs to allocate sufficient time to allow distributors to accommodate the changes necessary in implementing a Board Asset Management Standard.

3.2 How might coordinated regional planning between utilities and third parties (e.g., municipalities) promote the efficient and cost-effective development of infrastructure and enhanced regulatory predictability, while maintaining reliability and system integrity? What are the implications, if any, for distribution network investment planning?

In the PWU's view, it is plausible that coordinated regional planning could promote the efficient and cost-effective development of infrastructure and enhanced regulatory predictability. However, there are a number of issues that require clarification and the Board's commitment and support to ensure that such an exercise is worthwhile.

There should be clarity about the differences and similarities between the regional planning projects underway under the Ontario Power Authority ("OPA") and the regional planning being proposed by Board staff.

Stakeholders in the past requested clarification about the OPA's regional planning process and the OPA responded by a letter dated February 12, 2012 clarifying the process.[7] Part of the letter supports Board staff's understanding of the differences between the two initiatives:

> **The OPA recognizes that distributors and transmitters conduct ongoing connection planning activities that are associated with growth in demand, connecting generators, or addressing reliability issues, and that are more local in nature than the OPA's joint regional planning studies. These planning activities are typically driven by specific customer requests where dedicated connection facilities are required, and where upstream transmission network capacity is available. The expectation is that transmitters will advise the OPA of such planning activities and of their outcomes. The OPA expects that regional plans will be updated on a regular basis (e.g., every 3-5 years) or as needed if conditions change.**

[7] Description of the OPA's regional planning process, posted at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/OPA_Regional_Planning_Process.pdf

However, the OPA's description of the process in regional planning, further down in the letter, in the PWU's view overlaps with the anticipated process for the RRFE proposed regional planning:

> **Under the OPA's process, each regional plan is developed by a study team consisting of representatives of the OPA, affected LDCs and transmitters, and the IESO. The data collected for the study typically includes load forecasts provided by LDCs, conservation forecasts and information on local generation provided by the OPA, and where applicable the LDC, and technical system information provided by the IESO and Hydro One. In addition, studies consider other inputs such as municipal or regional growth, infrastructure, or energy plans, LDCs' conservation activities and distribution plans, sustainment plans for distribution and transmission infrastructure, and any other information relevant to the area. As the study lead, the OPA reviews and coordinates these inputs and ensures data quality and consistency. The OPA also leads the assessment of needs based on the study inputs.**

The PWU recognizes that the OPA regional planning studies are probably relatively high level in nature as the OPA does not engage in matters related to distribution system planning. However, given the similarities of the activities involved in the two regional planning initiatives, the issue of whether regional plans under the Board's Regional Planning initiative should be implemented in conjunction with the OPA's or whether the completion of the latter should be a precondition for the regional plans under the Board's initiative should be given further thought. The major inputs and activities under both initiatives are load forecast, generation connection forecast, and land use planning information. Coordination of the two initiatives is required to avoid confusion and duplication of effort on the part of the distributors and transmitters. In fact, it might not be necessary to formalize the current informal regional planning which is already happening provided the Board takes action to amend the current cost responsibility provisions in the TSC which appear to be barriers to effective regional planning (see Section 3.2).

The other issue affecting the outcome and efficacy of regional planning is whether the Board would support and approve regional plans and the investment decisions thereof once the plans are integrated into the distributors' Network Investment Plan. Coordination with regional development plans of municipalities would require that regional plans have long-term views of the needs of the distribution and transmission systems, which occasionally could mean distributors and transmitters need to make investments today for system expansion and upgrades that may happen in the future. The current framework which is based on the principle of “used and useful” is a barrier to such a possibility and without the Board’s support the efficacy of regional planning will be undermined.

3.3 How might the Board facilitate regional planning and the effective execution of the resultant plans as appropriate?

The PWU submits that the first and most pressing measure the Board needs to take in order to facilitate effective regional planning is to remove or minimize barriers to regional planning under the current framework. These barriers are largely related to cost responsibility as provided in the TSC. Specifically, effective regional planning would require:

a. the reclassification of 115 kV lines that perform both a Connection and a Network function as Dual Function Lines;

b. the reclassification of all 230/115 kV auto-transformers and the associated switchgear as Network assets;

c. the removal or modification of section 6.3.6 of the TSC; and,

d. the elimination of the provision that limits the need for a capital contribution/rebate to five years as currently set out in section 6.2.24 of the TSC.

Moreover, the Board can facilitate regional planning by supporting a long-term view of utility infrastructure investments. For example, the Board should enable cost recovery of investments that will have to be made today but which will have benefits in the future (e.g. acquiring corridors for future development.)

3.4 If we revise cost responsibility under section the Transmission System Code in respect of transmission line connection facilities to pool the costs, should the pooling be on a province-wide basis, a regional basis, or some

combination? Should the cost responsibility rules for industrial customers and distributor customers be the same? Why or why not?

In the PWU's view, if the Board were to revise cost responsibility in respect of transmission line connection facilities and pool the costs, pooling on a province-wide basis as opposed to a regional basis would have major advantages.

Pooling on a regional basis might not go far enough in effectively addressing the current issue for which pooling is proposed as a solution. Distributors in many regions with low customer bases often find the cost of such connection facilities too high. As Ms. Susan Frank of Hydro One noted in her response to a question from the Board Chair at the March 28-30, 2012 RRFE consultation, some areas simply cannot afford to pay for the transmission facilities that they need and that today's system is basically a pooled system:

> **MS. LECLAIR: Let me ask you a follow-up question. I think, Susan, it was in your comments about pooling in terms of the transmission. So if the solution is transmission, the cost allocation construct is the problem. When you talk about pooling, are you talking about pooling provincial wide or on a regional basis?**
>
> **MS. FRANK: It would be provincial wide, because it doesn't help a lot if it is on a regional basis. The regions that are normally -- like, in the case we have with Rene, it is the Waterloo, Kitchener, Guelph, Cambridge. That area by itself cannot pay for the transmission that they need. They just don't have enough people in that area. So when we talk about pooling, we are talking about all of Ontario. It is part of the connection pool. Everybody in Ontario would support it. And I appreciate that the thing that normally happens when you say that, people say, Well, my people and my neighbourhood are not getting the benefit. Why should we support the people who are getting the benefit? My feeling is your day will come. You likely had a day in the past and you will have a day in the future. So it is part of -- I believe the system we have today is really very much a pooled system to start with, you know. Like, we don't really have individual rates for individual people who get the specific benefit. There is a lot of pooling that goes on.** [8]

Another advantage is that compared to the option of a combined regional and provincial pooling, pooling on a province-wide basis would lessen regulatory effort and costs in the determination of the beneficiaries of a facility and the appropriate cost allocation.

[8] Ontario Energy Board, RRFE Stakeholder Conference, Transcript, volume 2, March 29, 2012, pp 41-42

3.5 How can the Board satisfy itself that multi-year investment plans are appropriate?

There are a number of reasons why multi-year investment plans are appropriate.

To be effective and sustainable the RRFE must recognize that current and future utility capital spending is unlike historical capital spending and that efficient network investment planning requires regulatory certainty and stability. Regulatory approval for multi-year investment plans is a significant pre-requisite for such certainty and stability. It is imperative for the Board to recognize the need for the distributors to replace aging assets at an accelerated rate and have a long-term vision of investment requirements.

Regulatory approval of multi–year investment plans are in-line with the long term asset management plans that support utilities' investment plans.

Further, regulatory approval of multi-year investment plans will provide for rate smoothing for consumers. Investments not supported by rates over IRM terms and included in cost of service rate adjustments can result in significant rate volatility.

The ICM as an alternative does not provide the regulatory certainty that approval of a multi-year investment plan does. As noted in Section 3.1.1, regulatory certainty is required for efficient network investment planning. However, even with the regulatory option for a multi-year investment plan an ICM should be available to the utilities to address contingencies that arise over the IR term.

3.6 How should smart grid investments be treated (i.e., as part of rate base, or based on type of activity/asset)?

Smart grid investments that are a part of a utility's ongoing asset condition management process that addresses network service reliability and cost efficiency, would be a part of a utility's network investment plan and would not be included in a utility's Smart Grid Plan. Costs associated with these investments would be recovered through the utilities' rates. On the other hand, smart grid investments that are incremental to a utility's network investment plan would be included in its Smart Grid Plan with costs for these investments recovered through rate riders. The prudence of the utility's Smart Grid Plan would be established in a review of the plan's conformance with the Board's guidance. Given that the utility makes the investments in both the utility's network investment plan and the Smart Grid Plan all the smart grid capital investments would enter into rate base as they come into service. Whether smart grid investments/costs are expensed or capitalized would be a matter of accounting and utility business policy.

3.7 What empirical and qualitative tools and methods might be used to inform: (a) utility planning processes; (b) utility applications to the Board; and/or (c) the Board's review of utilities' plans?

The PWU believes that investment planning consistent with Board established standards would be the best way of ensuring economic efficiency and cost effectiveness of proposed network investments. However, if the Board is not prepared to establish standards, qualitative information to demonstrate the economic efficiency and cost effectiveness of a proposed network investment could consist of a description on how the utility's asset management planning compares to recognized standards or best practice principles. While ensuring consistency with Board standards through a Board established self-certification process would expedite the review process, the latter would not present such an opportunity and would result in a more onerous review process.

4. PWU's Response to Board Staff Questions Posed in Investment Planning and Regional Planning Discussion Papers

4.1 Distribution Network Investment Planning (EB-2011-0377)

4.1.1 Are there elements of the Code, the GEA Filing Requirements and the Benefits Framework that require further alignment to promote, for example, the consistent categorization of investments for all regulatory purposes related to network planning?

According to the Benefits Framework, investments undertaken by a distributor for the purpose of accommodating REG can have 'direct benefits' for the distributor's load and non-REG customer. Such benefits include improvements in service quality or the deferral/avoidance of investments otherwise needed to accommodate new load. The PWU's concern is that under the current practice, the quantification, valuation, and monetization of these direct benefits is impractical and tends to be arbitrary. Direct benefit in the form of deferral of investments otherwise needed to accommodate new load, for example, is highly subjective. Similarly the PWU submits that the Board is not in a position at this time to quantify service quality improvements accruing to load customers as a result of the connection of a renewable generation. To quantify direct benefits related to service quality the Board would need to have established levels of standards. A distributor's revenue requirement should provide for the sustainability of the service quality standard. Where a distributor's service quality performance is below the required standard, any eligible investment that improves service quality performance up to the standard can be considered to contribute to direct benefits. Where the eligible investment contributes to service quality performance above the standard, there would be no added value for the consumers and there would be no associated direct benefits from the consumers' perspective. Therefore the PWU submits that in order for the Board to be able to assess improved service quality direct benefits related to eligible investments, it would first need to establish service quality standards based on customer WTP surveys. Any assessment of such direct benefits in the absence of service quality standards would be arbitrary and can result in consumers paying for service quality performance improvements that they neither want, need or value.

In this respect, the PWU submits that under the current circumstances the Board might consider addressing any direct benefits that are reasonably identifiable and quantifiable, under the Distribution System Code. Direct benefits that are too difficult to identify and quantify that only serve to increase the distributor's workload should be disregarded.

4.1.2 Are there elements of the CoS Filing Requirements and the GEA Filing Requirements that could be further harmonized, having regard to the fact that both address facets of a distributor's overall network plan?

The PWU submits that the current requirement under the CoS Filing Requirements for the distributor to file at a minimum a forecast of three years' capital expenditures (i.e., Test year plus two additional years) can be increased to a five-year forecast to be consistent with the GEA Filing Requirements which state that a GEA Plan should cover a five year time horizon. The PWU notes that the materiality thresholds in the GEA Filing Requirements refer to the total cost of investments included in a distributor's GEA Plan, whereas the materiality thresholds in the CoS Filing Requirements apply on a project-specific basis. The PWU supports the current practice given that a GEA Plan in many cases might not have detailed information about specific projects that might or might not be chosen to proceed as part of the proposed total investment.

4.1.3 What are the merits and key challenges of pre-establishing network investment assessment processes and corresponding filing requirements based on criteria involving the characteristics of the proposed investments?

The merits of pre-establishing network investment assessment processes and corresponding filing requirements based on criteria involving the characteristics of the proposed investments is the certainty it provides on the regulatory expectations related to the investment assessment processes and filings for various investment types. Consistency with the pre-established processes and filing requirements aligns the utility's evidence/assessments with regulatory expectations and should result in the expedited review of the application.

The challenge would include ensuring flexibility to accommodate individual investment needs of vastly different utilities.

4.1.4 Should the Board consider mechanisms, such as an incentive-based approach to information filings, to promote network planning filings that achieve a requisite degree of quality?

In the PWU's view what is required is for the Board to clearly articulate criteria on what the Board considers to constitute "quality" information.

4.1.5 Are there elements of the GEA Filing Requirements related to qualitative investment planning information that can be usefully adapted for CoS Filing Requirements purposes?

The PWU submits that both the quantitative and qualitative information (for example business objectives and values of the distributor, consultations with stakeholders, alternatives considered by the distributor, justifications for chosen projects, etc.) filed by distributors under the CoS filing requirements are sufficient. Qualitative information under the GEA filing requirements such as consultations with interconnected transmitters and distributors and with the OPA to realize cost efficiency, etc. partly reflects the nature of investments under the GEA plan and so may not be applicable to CoS filings.

4.1.6 What are the best ways qualitative information can be used by a distributor to demonstrate the economic efficiency and cost effectiveness of their proposed network investments and should such methods differ depending on investment category or purpose?

Investment planning consistent with Board standards would be the best way of ensuring economic efficiency and cost effectiveness of proposed network investments. However, if the Board is not prepared to establish standards, qualitative information could consist of a description on how the utility's asset management planning compares to recognized standards or best practice principles. While ensuring consistency with Board standards through a Board established self-certification process would expedite the review process, the latter would not present such an opportunity and would result in a more onerous review process.

4.1.7 Are there quantitative analyses that should be required in respect of planned network investments and therefore included in the CoS Filing Requirements?

While the PWU is of the view that the quantitative analyses that are already filed with CoS applications are sufficient, there may be the possibility of adopting quantitative analyses that are normally filed under the Transmission filing requirement if they are relevant to distribution. The PWU also recommends a quantitative analyses (e.g. forecast) of the state of asset demography (for example the percentage of assets under different categories that would reach end-of-life) over a 10-20 year time horizon assuming different rates of replacement.

4.1.8 In general and/or specifically in relation to the PA Model: what are the merits and potential weaknesses of using information on the potential direct and indirect bill impacts of proposed network investments for regulatory assessment purposes?

There is an advantage in having the information on bill impacts of proposed network investments for regulatory assessment purpose in so far as the factors behind the bill impact are in the control of the distributor. Such information may be used by the distributor to plan alternative investments and by the Board to ensure that rates are just and reasonable. Information on potential direct and indirect bill impact can also help the Board and distributors to devise *ex-post* rate mitigation plans to avoid rate shocks. On the other hand, the use of information about direct and indirect bill impacts including those resulting from factors beyond the control of the distributor can result in arbitrary cuts and disapproval of needed work programs by the Board which in turn would compromise service quality and reliability. It will distort the meaning, objective and process of assessment of proposed investments. Once customer value and expectation has been determined, proposed investment should be guided by need and cost. The cost aspect of the assessment normally implies that the best alternative that minimizes cost is selected. That is and should be the Board's concern. Once the need for a project is established and the cost is deemed to be the best of all the alternatives considered, the project should go ahead regardless of the bill impact.

4.1.9 What are the merits and potential weaknesses of using estimates of direct and indirect bill impacts for network investment planning purposes (e.g. project selection; program configuration; scenario analysis)?

There are no merits in using estimates of bill impacts beyond the control of the distributor for network investment planning purposes. It not only distorts the distributor's planning and prioritization process but also shifts responsibility from government policy and generators (with respect to the type and location of generation, etc.) to the distributors.

4.1.10 What are the key issues to consider when determining whether and if so in what form information on estimated direct and indirect bill impacts should be included in filing requirements?

The key issues to consider include relevance and use of the information for the purpose of assessing the cost effectiveness of network investments; the regulatory burden it creates and the reliability of the information and data (e.g. forecasts based on factors beyond the control of the distributor). Only bill/rate impacts that are directly the result of a distributor's revenue requirement should be filed in their CoS filings. With respect to bill or rate impacts attributable to specific utility network investments or projects, such information could be provided in rate applications as is the current practice.

4.1.11 Should the Board consider mechanisms that would help ensure the network planning policy framework is regularly informed of network investment outcomes and planning process developments?

Given that network plans can have relatively long time horizons, it is important that the network planning policy framework is flexible enough to adapt to changes and new developments such as the emergence of new planning drivers, shifts in investment priorities and changes in asset management and network planning processes. The Board therefore should consider mechanisms to be regularly informed of network investment outcomes and planning process developments.

4.2 Regional Planning (EB-2011-0043)

4.2.1 Staff requests general feedback on its proposed approach to Regional Planning.

As indicated earlier, the PWU's main concern with the proposed formalized regional planning is the potential duplication of effort by distributors, transmitters and everyone involved including the Board, the OPA and intervenors as a result of two regional planning exercises in the province: one under the OPA; and, one proposed in this initiative. In the PWU's view, given the similarities of the activities involved in the two regional planning initiatives (load forecast, generation connection forecast, land use planning documents, etc.), the issue of whether regional plans under the Board's Regional Planning initiative should be implemented in conjunction with the OPA's or whether they can be undertaken separately should be given further thought and consultation. Coordination between the two appears very important.

4.2.2 Staff has proposed that an obligation be placed on distributors to provide the transmitter with an updated forecast and the relevant land use planning documents (where applicable) at least every five years and for a period covering at least five years. In relation to the provision of the relevant information, should it be more frequent? Should the forecast cover a longer minimum period of time than five years (e.g., 10, 15 years)?

The distributors should provide the transmitter with an updated forecast and relevant land use planning documents as appropriate at least every five years or earlier if there is some significant triggering activity that would warrant doing so. However, the plan should be for a period covering at least ten years. The minimum ten year forecast requirement mitigates the problems relating to accuracy and usefulness of load and generation forecasts of longer years and the work load on distributors if they were required to provide 20-25 year forecasts on a regular basis. On the other hand, the 10-year requirement would give the transmitter a long enough time period for it to assess the respective transmission needs of the distributors within a region collectively and to plan accordingly. It is also possible for an annual update check for new and significant information. For example, if 2 years into a 5 year cycle it becomes apparent that a significant amount of renewable generation was expected to connect into an LDC, or some major load growth or infrastructure triggering event occurs, either positive (new industrial customer) or negative (loss of major industry), then it would be appropriate to update information.

4.2.3 In cases where a transmitter is requested by distributors to be involved in the development of multiple regional plans at the same time, what criteria should be used by the transmitter for determining the prioritization of the regional plans in the event of transmitter resource constraints?

In general plans that address near-term needs should be presented as action items for immediate or early implementation. Regional plans that call for expedited action based on evidence that shows pressing reliability and service quality concerns (for example comment from the OPA or the IESO) should be given priority by the transmitter. Similarly, government policy requirements (e.g. directives) may need to be considered by the transmitter.

4.2.4 Do distributors foresee any problems in relation to obtaining the relevant land use planning documents from the applicable authority in their service area for the purpose of providing those plans to the transmitter? If so, please explain.

In the PWU’s view this question should be addressed by distributors and transmitters based on their experience. In general however, one possible area of difficulty is where a distributor’s service area covers more than one municipality/county/district. In such circumstances, uniformity and availability (when needed) of land use planning documents and differences in documents used by various municipalities could prove problematic.

4.2.5 Are any of the approaches discussed above appropriate for determining suitable regions for the purpose of regional planning? Why or why not?

The PWU supports the Board staff suggested hybrid approach which would involve the establishment by the Board of relatively broad ‘predefined’ regions across Ontario. The PWU however suggests that the Board be assisted by knowledgeable transmission system planners at Hydro One, the IESO and the OPA in developing a strong definition of “region” based on their knowledge of the system today and foreseeable future, including a comprehensive perspective using all the considerations in a regional planning requirement.

4.2.6 In relation to the approaches discussed above (how regions are determined), are there any proposed modifications that would enhance their suitability?

See response to Section 4.2.5 above.

4.2.7 Are there any other criteria, beyond transmission asset functionality, that should be used in the determination of appropriate regions within Ontario for regional planning purposes?

In the PWU’s view, Transmission Asset Functionality is a reliable criterion; however, input from Hydro One, the IESO, the OPA as suggested in Section 4.2.5 above would be helpful.

4.2.8 Are there other alternative approaches that could be used to determine appropriate regions? If so, please identify the proposed regional structure and explain the rationale and benefits associated with the proposed approach including reasons why it may be more suitable than Board staff’s preferred approach.

The PWU has no alternative approaches to present.

4.2.9 Do stakeholders agree that assets such as 230/115 kV auto-transformers and the associated switchgear should be reallocated to the Network pool? If not, why not and what other approaches might be considered to achieve consistency across Ontario?

The PWU agrees with Board staff that all 230/115 kV auto-transformers and the associated switchgear be classified as Network assets in order to optimize use of the transmission system. Such reclassification involving assets where there are multiple beneficiaries would be consistent with the 'beneficiary pays' principle and supports achievement of the Board's goal of optimal investments for the regional planning initiative.

4.2.10 Do stakeholders believe that 115 kV lines should be classified as Dual Function Lines or as Network lines where they perform both a Connection and a Network function? Please explain the rationale for the approach supported.

The PWU submits that 115 kV lines that perform both a Connection and a Network function should be classified as Dual Function Lines and the costs are allocated to both the Line Connection and Network pools based on the extent each relevant asset is used for Connection vs. Network purposes. There is no question that reclassifying such 115 kV lines as Network assets would be simpler from an administrative perspective; however, doing so would be inconsistent with the principles of cost causality and beneficiary pays.

4.2.11 Should the Board consider reclassifying any other Line Connection assets beyond 115/230 kV auto-transformers, the associated switchgear and certain 115kV lines for the purpose of facilitating regional planning? If so, please identify those assets and explain why the current classification could present a barrier to regional planning.

The PWU has no comment on this issue.

4.2.12 Of Board staff's proposed changes to section 6.3.6 discussed above, which would better achieve the intended goal of resulting in greater regulatory predictability? If the latter option (ii), please propose the list of specific circumstances.

The PWU supports Board staff's suggestion to rectify the confusion about the "otherwise planned" provision in Section 6.3.6 of the TSC, first by removing "load growth" and then limiting Section 6.3.6 to transmission Connection investments that are necessary to satisfy the reliability requirements set out in the IESO's Ontario Resource and Transmission Assessment Criteria document. This approach would not only recognize transmission Connection asset upgrades required by distributors which are in turn driven by the connection of renewable energy generation facilities at the distribution level, but also would be in line with the Board's intent for Section 6.3.6 of the TSC as articulated in its September 6, 2007 Connection Procedures Decision, which stated that:

> **Section 6.3.6 of the Code is an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements to the system for reliability and integrity improvements which have been already identified and planned for by the transmitter, except for any additional costs associated with the advancement of the improvements at the request of the customer.[9]**

4.2.13 Are there other alternative changes to section 6.3.6 that the Board should consider? If so, please explain the change in detail and identify the benefits.

The PWU has no alternative changes to suggest.

4.2.14 What would the advantages and disadvantages be associated with removing section 6.3.6 from the TSC altogether, as an alternative to the options Board staff proposed above? If section 6.3.6 were to be removed, would other changes to the TSC also be required as a consequence?

The advantage of removing section 6.3.6 altogether is that it avoids the difficult task of determining whether a connection facility has been "otherwise planned" by the

[9] Decision and Order in a combined proceeding regarding the connection procedures of Hydro One and GLP (EB-2006-0189 and EB-2006-0200), September 6, 2007, page 21, Para 7

transmitter or triggered solely by a connection customer. The disadvantage is that it creates the potential for the connecting customer to pay for a connection asset which the transmitter was already planning to invest in and which might benefit other customers thereby potentially shifting cost responsibility and undermining the principle of “beneficiary pays”.

If Section 6.3.6 were to be removed, Section 6.1.4 (i) of the TSC which deals with requirements of a transmitter’s connection procedures will need to be removed. Section 6.1.4 (i) puts an obligation on the transmitter to provide a customer with the most recent version of the plans required by section 6.3.6 that cover the applicable portion of its transmission system. The removal of section 6.3.6 of the TSC might also effect change in other documents such as transmission connection agreements and Connection Cost Recovery Agreements.

4.2.15 Are there any other criteria that should be used in addition to the above for the evaluation of approaches in relation to load connection cost responsibility?

While related to regulatory predictability and administrative efficiency which would facilitate investment, planning and decision-making, certainty and timeliness of cost recovery should be added. The administrative efficiency criteria relating to the level of effort required by proponents and interested parties for effective participation would be optimized if proponents and interested parties only have to go through one regional planning process. In that process, for the interested parties, it is most effective if there is transparency / access to modelling information such that they can satisfy themselves that their interests are being considered.

4.2.16 Which approach among the cost responsibility options identified above would best achieve the Board’s stated goals in relation to this initiative?

The PWU recognizes that each of the cost responsibility options has strengths and weaknesses viewed in terms of objectives with respect to principles in cost responsibility (cost causality and beneficiary pays), regulatory predictability and administrative efficiency, economic efficiency and cost effectiveness, regulatory predictability and interest of the rate payer.

In the PWU's view, since the status quo is a benchmark against which other options can be compared, the first step before choosing any other cost responsibility option should be to consider if the status quo can be improved to address the above cited objectives. A radical departure from the status quo is advisable only if the status quo is irreparably broken and unsustainable. Otherwise, the departure can create unnecessary shocks, confusion, significant administrative changes and unexpected outcomes.

The PWU recommends the following cost responsibility options presented in order of preference:

1. **The Status quo with the following changes**:
   a. The reclassification of 115 kV lines that perform both a Connection and a Network function as Dual Function Lines as proposed earlier;
   b. The reclassification of all 230/115 kV auto-transformers and the associated switchgear as Network assets;
   c. The modification to section 6.3.6 of the TSC as indicated under Section 4.2.12 above; and,
   d. The elimination of the provision that limits the need for a capital **contribution/rebate to five years as currently set out in Section 6.2.24 of** the TSC.

2. **Status quo sub-option**: **Smoothing option:** i.e. the recovery of the amount that would have been recovered through a capital contribution would be recovered by the transmitter over a period of 20 years from the applicable distributor(s) through a rate rider.

The PWU believes, this option together with the recommended changes above (see option 1a & 1b above) will have the additional advantage, relative to the status quo, of avoiding the payment by especially small distributors of a large lump sum capital contributions upfront (which in turn will encourage distributors to be forthcoming and willing to participate in regional plans); moreover, this approach would be more equitable from an intergenerational equity perspective since cost recovery would more closely match the life of the asset. The advantages of this approach far outweigh the disadvantage which is the additional administrative burden for the transmitter due to the need to administer multiple rate riders.

3. **Pooling sub-option: Basic service option**

   Under this approach a basic level of connection service would be available to all distributors on a pooled basis; the basic level of service being determined based on criteria such as maximum distance to the grid and single circuit supply. In the PWU's view this approach together with the applicable changes recommended earlier (see option 1a & 1b above) has all the advantages of the Full Pooling option, whenever basic service applies; additionally it would avoid cross-subsidization in cases where distributors request "premium service".

4.2.17 Are there other cost responsibility options that should be considered by the Board? Participants that wish to put forward alternative proposals for consideration in terms of cost responsibility are encouraged to include in their comments not only a detailed description of each proposal, but also the underlying rationale and principles that support the proposal.

The PWU has no other options to suggest.

4.2.18 If the Board were to: (i) adopt Board staff's proposed changes to section 6.3.6 of the TSC; (ii) eliminate the five year sunset period for capital contribution rebates; and (iii) reclassify certain Connection assets, all as discussed above, would it be appropriate to retain the status quo cost responsibility regime?

Yes. (see Section 4.2.16)

4.2.19 Which approach would be more appropriate in relation to the 115 kV Connection lines that perform Network functions – the Hybrid cost responsibility option discussed above (recovery via the Line Connection rate) or reclassification as Network assets (recovery via the Network rate) or reclassification as Dual Function Lines (recovery via both the Network and Line Connection rates) as discussed above? Please provide a detailed rationale for your preferred approach.

Reclassification as Dual Function Lines-recovery via both the Network and Line Connection rates would be the more appropriate approach (see Section 4.2.10).

4.2.20 Are there any specific circumstances where generators should not be responsible for the costs related to an upstream upgrade that they triggered? If so, please identify those circumstances and the reasons why the generators should not be responsible for those costs.

In the PWU's view, so long as the upstream upgrade is triggered by the generator, the generator should be primarily responsible for the cost of the upgrade. Therefore the status quo is appropriate and consistent with the cost causality principle. However, Board staff might address the issue from the "beneficiary pays" principle perspective – including potential for cost sharing with other parties if appropriate.

All of which is respectfully submitted