EB-2016-0050

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* by Hydro One Inc. for leave to purchase all issued and outstanding voting securities of Great Lakes Power Transmission Inc.

ARGUMENT COMPENDIUM OF THE SCHOOL ENERGY COALITION

July 14, 2016

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In compliance with the Filing Requirements, information is provided pertaining to GLPT's assumed future cost structures using "without transaction" and "with transaction" assumptions.

Table 2 provides GLPT's "without transaction" forecast of capital expenditures. The amounts shown are based on HOI's review of GLPT's draft capital expenditure plan.[2]

TABLE 2 –GLPT CAPITAL EXPENDITURE FORECAST WITHOUT TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8

Capital expenditure reductions arising from the transaction are expected to result from some asset redundancy, the economic scale of Hydro One's operations, and potential savings from adopting Hydro One's asset management programs. The level of actual realized savings is uncertain and will depend on the experience gained by the parties in 2017 and 2018, circumstances prevailing when operational integration plans are implemented, as well as external factors affecting operations (e.g. storms). In order to reflect this uncertainty, Hydro One has developed two "with transaction" capital forecast scenarios.

Scenario Descriptions

The first scenario is referred to as the Base Case. This scenario assumes that synergy savings occur in years 3 to 5 and relate to cost reductions associated with the SCADA system, transport and work equipment, spare parts inventory, and asset replacement costs. In years 6 and 7, costs attributable to the relocation of a backup control centre are expected to be avoided given Hydro One's existing infrastructure. Additional cost savings are assumed in years 3 through 10 due to GLPT's use of other Hydro One operational programs, such as its Asset Risk Assessment model. Barring unforeseen circumstances, the estimated savings shown in the Base Case are attainable and may potentially be exceeded.

[2] GLPT's Transmission System Plan will be filed with its 2017/18 Cost of Service application later this year

The second scenario is referred to as the High Case. The assumptions made in this Case are the same as the Base Case, but capital expenditures are assumed to be reduced by an additional 10% in years 3 to 10. These savings could arise from IT system scale optimization (e.g. telecommunications, HR, financial etc.), the avoidance of significant costs for improvements to redundant buildings and facilities, and strengthening purchasing economies of scale.

Table 3 below provides the results of the Base and High capital savings analysis.

TABLE 3–CAPITAL EXPENDITURE FORECAST WITH TRANSACTION SHOWING BASE AND HIGH POTENTIAL COST SCENARIOS

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base	19.4	16.2	14.7	14.1	15.3	17.6	16.9	17.8	16.9	17.3
High	19.4	16.2	13.2	12.7	13.8	15.8	15.2	16.0	15.2	15.6

OM&A Comparative Cost Forecast

Operating, maintenance and administrative ("OM&A") cost forecast information for the "without transaction" and "with transaction" assumptions is presented in this section.

Table 4 below provides a forecast of GLPT's average annual OM&A costs estimated for each year of the rebasing deferral period. The forecast is based on GLPT's 2017 and 2018 forecast and adjusted for inflation for the subsequent years.

TABLE 4 –GLPT OM&A COST FORECAST WITHOUT TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OM&A	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.4	13.7

Similar to the Capital Expenditures assessment, the "with transaction" OM&A forecast has been developed using the assumption that GLPT will continue to operate on a stand-alone basis during 2017 and 2018. After 2018, the areas in which OM&A savings are expected relate to scale and operational synergies. These include procurement, maintenance programs, planning, operations, project management, engineering, scheduling, back-office administration, corporate governance, etc. Additional areas of savings opportunities may include information technology, insurance and research and development. Optimization of these functions may contribute to the overall efficiency benefits associated with this Transaction. Given the uncertainties associated with developing a 10 year savings forecast, HOI has prepared two case scenarios.

OM&A Case Scenarios

The first OM&A scenario is referred to as the Base Case. This scenario assumes that a 10% cost savings level on GLPT's "without transaction" costs is achieved in years 3 to 10 of the rebasing deferral period. In years 8 through 10 an additional $500,000 of achieved savings is assumed to reflect the legal and financial amalgamation of the two entities which is expected to occur in that timeframe. No incremental cost savings are expected in 2017 and 2018 given the assumption that GLPT operates as a stand-alone entity in this timeframe, akin to a "without transaction" scenario. Barring any unforeseen circumstances, the estimated savings presented in the Base Case are attainable and may potentially be exceeded.

The second OM&A scenario is referred to as the High Case. The assumptions made in this Case are the same as the Base Case with the exception that achieved cost savings in each of years 3 through 10 reach a 30% level on GLTP's "without transaction" costs. The High Case illustrates the magnitude of potential savings if greater operational integration cost efficiencies are achieved in the identified areas.

OM&A Sensitivity Analysis Results

Table 5 below provides the results of the OM&A sensitivity analysis.

TABLE 5 –OM&A COST FORECAST WITH TRANSACTION
SHOWING BASE AND HIGH POTENTIAL COST SCENARIOS

$/Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base	11.5	11.7	10.7	11.0	11.2	11.4	11.6	11.4	11.6	11.8
High	11.5	11.7	8.3	8.5	8.7	8.9	9.0	8.7	8.9	9.1

Qualitative Benefits

Qualitative benefits associated with the transaction include the following:

- Coordinated regional planning, emergency response and ongoing outage management activities are expected to create benefits;
- Opportunities for GLPT's management and staff to work within the Hydro One organization. These resources will help address expected retirements and other attrition;
- The coordination of Hydro One and GLPT's existing staff is expected to improve regional system knowledge and allow for the implementation of best in class programs.

Incremental Transaction Costs

Incremental transaction costs include costs for items such as data and other IT Systems integration, regulatory approvals and legal advice. These types of costs will be financed through productivity gains associated with the transaction and will not be included in either GLPT or Hydro One's revenue requirement and thus will not be funded by ratepayers. These costs are expected to be incurred during the deferred rebasing period, and will therefore be offset through the productivity gains achieved during this time period.

Ontario Energy Board
Commission de l'énergie de l'Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications. This Handbook uses the term consolidation to be inclusive of mergers, acquisitions, amalgamations and divestitures (MAADs).

The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.

Consolidation also enables distributors to address challenges in an evolving electricity industry. This includes new technology requirements to meet customer expectations, changing dynamics in the electricity sector with the growth of distributed energy resources and to undertake asset renewal. Distributors will need considerable additional investment to meet these challenges and consolidation generally offers larger utilities better access to capital markets, with lower financing costs.

Distributors are also expected to meet public policy goals relating to electricity conservation and demand management, implementation of a smart grid, and promotion of the use and generation of electricity from renewable energy sources. Delivering on these public policy goals will require innovation and internal capabilities that may be more cost effective for larger distributors to develop or retain.

The OEB recognizes that there is a growing interest in and support for consolidation. The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.

Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applicants. This Handbook will provide further clarity to applicants, investors, shareholders, and other stakeholders. The Handbook also discusses the rate-making policies associated with consolidations and sets out the timing of when such matters will be considered by the OEB.

While the Handbook is applicable to both electricity distributors and transmitters, most of the OEB's policies and prior OEB decisions have related to distributors. Transmitters should consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations.

2. The OEB Authority and Review Process

This section describes the OEB's legal authority in approving consolidation applications and clarifies how the OEB reviews these applications.

The OEB legislative authority

OEB approval is required for consolidation transactions described under section 86 of the *Ontario Energy Board Act, 1998* (OEB Act). (For ease of reference, Section 86 is reproduced in Schedule 1 of this Handbook.) Briefly, these transactions are as follows:

- A distributor or transmitter sells or otherwise disposes of its distribution or transmission system as an entirety or substantially as an entirety to another distributor
- A distributor or transmitter sells a part of a distribution or transmission system that is necessary in serving the public
- A distributor or transmitter amalgamates with another distributor or transmitter
- A person acquires voting securities of a transmitter or distributor or acquires control of a corporation with voting shares

Section 86(2) relating to voting securities does not, however, apply to the acquisition or sale of shares in Hydro One, a company created by the Crown under section 50(1) of the *Electricity Act, 1998*, which is explicitly exempt under section 86(2.1) from the conditions stipulated in section 86(2).

The Application Review Process

This Handbook applies specifically to applications under sections 86(1)(a) and (c) and sections 86(2)(a) and (b) of the OEB Act, which are processed through the OEB's adjudicative review process. Sections 86(1)(a) and (c) of the OEB Act relate to asset sales and amalgamations. Section 86(2) of the OEB Act relates to voting securities. To assist applicants, the OEB has developed Filing Requirements in Schedule 2 of this Handbook which set out the information that needs to be provided in an application. These Filing Requirements replace the form entitled **Application Form for Applications under Section 86 of the OEB Act** that was previously posted on the OEB's website.

Applications filed under section 86(1)(b) of the OEB Act are generally processed through the OEB's administrative review process, typically without a hearing. These applications generally include the sale of smaller scale distribution or transmission assets from one distributor or transmitter to another, or to a large consumer who is served by the same assets. For these applications, applicants may continue using the form entitled **Application Form for Applications under Section 86(1)(b) of the OEB Act** that is posted on the OEB's website, (http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms#maad).

The OEB may elect to process a section 86(1)(b) application under its adjudicative review process if the OEB considers that certain aspects of an application could affect service to the public and/or have a material effect on rates. This will be determined once the application is filed with the OEB. In those circumstances, this Handbook will be applicable. Applicants who are of the view that their transaction is material should use this Handbook to inform their application.

3. The OEB Test

The No Harm Test

In reviewing an application by a distributor for approval of a consolidation transaction, the OEB has, and will continue, to apply its "no harm test". The "no harm" test was first established by the OEB in 2005 through an adjudicative proceeding (the Combined Proceeding).[1]

The “no harm” test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives, as set out in section 1 of the OEB Act. The OEB will consider whether the “no harm” test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The OEB’s objectives under section 1 of the OEB Act are:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
   1.1 To promote the education of consumers.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer’s economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

4. The OEB Assessment of the Application

This section sets out how the OEB applies the “no harm” test within the context of the performance-based regulatory framework, the Renewed Regulatory Framework for Electricity Distributors[2] (RRFE). This framework was established by the OEB in 2012 to

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[1] Combined Proceeding Decision - OEB File No. RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

[2] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

ensure that regulated distribution companies operate efficiently, cost effectively and deliver outcomes valued by its customers.

The Renewed Regulatory Framework

Ongoing performance improvement and performance monitoring are underlying principles of the RRFE. The OEB's oversight of utility performance relies on the establishment of performance standards to be met by distributors, ongoing reporting to the OEB by distributors, and ongoing monitoring of distributor achievement against these standards by the OEB.

An electricity distributor is required, as a condition of its licence, to provide information about its distribution business. Metrics are used by the OEB to assess a distributor's services, such as frequency of power outages, financial performance and costs per customer. The OEB uses this information to monitor an individual distributor's performance and to compare performance across the sector. The OEB also has a robust audit and compliance program to test the accuracy of reporting by distributors.

As part of the regulatory framework, distributors are expected to achieve certain outcomes that provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance by distributors and that utilities deliver on system reliability and quality objectives. The OEB uses processes to hold all utilities to a high standard of efficiency and effectiveness.

The OEB has a proactive performance monitoring framework that inherently protects electricity customers from harm related to service quality and reliability and has established the mechanisms to intervene if corrective action is warranted. The OEB will be informed by the metrics that are used to evaluate a distributor's performance in assessing a proposed consolidation transaction.

All of these measures are in place to ensure that distributors meet expectations regardless of their corporate structure or ownership. The OEB assesses applications for consolidation within the context of this regulatory framework.

The No Harm Test

The "no harm" test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives. While the OEB has broad statutory objectives, in applying the "no harm" test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector. The OEB considers this to be an appropriate approach, given the performance-based regulatory framework under which all regulated distributors are required to operate and the OEB's existing performance monitoring framework.

The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB's statutory objectives relating to conservation and demand management, implementation of smart grid and the use and generation of electricity from renewable resources. With these tools and the ongoing performance monitoring previously discussed, the OEB is satisfied that the attainment of these objectives will not be adversely effected by a consolidation and the "no harm" test will be met following a consolidation. There is no need or merit in further detailed review as part of the OEB's consideration of the consolidation transaction.

Scope of the Review

The factors that the OEB will consider in detail in reviewing a proposed transaction are as follows:

Objective 1 – Protect consumers with respect to price and the adequacy, reliability and quality of electricity service

<u>Price</u>

A simple comparison of current rates between consolidating distributors does not reveal the potential for lower cost service delivery. These entities may have dissimilar service territories, each with a different customer mix resulting in differing rate class structure characteristics. For these reasons, the OEB will assess the underlying cost structures of the consolidating utilities. As distribution rates are based on a distributor's current and projected costs, it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors. A key expectation of the RRFE is continuous improvement in productivity and cost performance by distributors. The OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers.

Consistent with recent decisions,[3] the OEB will not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of "no harm" as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term. In reviewing a transaction the OEB must consider the long term effect of the consolidation on customers and the financial sustainability of the sector.

To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. While the rate implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility.

Adequacy, reliability and quality of electricity service

In considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

The OEB's *Report of the Board: Electricity Distribution Systems Reliability Measures and Expectations*, issued on August 25, 2015 sets out the OEB's expectations on the level of reliability performance by distributors. In the Report, the OEB noted that continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or to maintain the same level of performance at a reduced cost.

Under the OEB's regulatory framework, utilities are expected to deliver continuous improvement for both reliability and service quality performance to benefit customers. This continuous improvement is expected to continue after a consolidation and will continue to be monitored for the consolidated entity under the same established requirements.

[3] Hydro One Inc./Norfolk Power Distribution Inc. – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. – OEB File No. EB-2014-0244

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

The impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity) will be assessed based on the applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

The impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will also be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and integration costs) to implement the consolidation transaction

In the Combined Proceeding decision, the OEB made it clear that the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test. While there may not be a premium involved with mergers, the OEB will nevertheless consider the financial viability of the newly consolidated entity.

Electricity distribution rates are currently based on a return on the historic value of the assets. If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity. In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed. Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.

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The OEB considers that certain aspects of a consolidation transaction are not relevant in assessing whether the transaction is in the public interest, either because they are out of scope, or because the OEB has other approaches and instruments for ensuring that statutory objectives will be met. Accordingly, the OEB will not require applicants to file evidence on the following matters as part of a consolidation application.

1. *Deliberations, activities, and documents leading up to the final transaction agreement*

As set out in the Combined Proceeding decision, and confirmed in recent decisions,[4] the question for the OEB is neither the why nor the how of the proposed transaction. The application of the "no harm" test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB's statutory objectives.

The OEB determined in the Combined Proceeding decision that it is not the OEB's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB. Accordingly, the OEB will not consider, whether a purchasing or selling utility could have achieved a better transaction than that being put forward for approval in the application.

Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans nor the negotiating strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB.

Applicants and stakeholders should not file any of the following types of information as they are not considered relevant to the proceeding:

- Draft share purchase agreements and other draft confidential agreements and documents utilized in the course of the negotiation process

[4] Hydro One Inc./Norfolk Power Distribution Inc. Decision and Order and Procedural Order No. 8 – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Woodstock Hydro Services Inc. Decision and Procedural Order No. 4 – OEB File No. EB-2014-0213

- Negotiating strategies or conduct of the parties involved in the transaction
- Details of public consultation prior to the filing of the application

2. <u>Implementing public policy requirements for promoting conservation, facilitating a smart grid and promoting renewable energy sources</u>

As previously discussed, the OEB's performance-based regulation, which includes performance monitoring and reporting based on standards, combined with the regulatory instruments of codes and licences, establishes a framework for success in achieving public policy requirements. A utility that does not meet established performance expectations is subject to corrective action by the OEB. Given these means for ensuring that public policy objectives are met by all regulated entities, the OEB is satisfied that the "no harm" test will be met for these objectives following a consolidation and there is no need or merit in further detailed consideration as part of a consolidation transaction. For these reasons, no evidence is required to be filed for these issues.

3. <u>Prices not related to a utility's own costs</u>

The OEB's review is limited to the components of the distribution business and the costs and services directly under a distributor's control. For example, one of the mandates of a distributor is to pass-through certain wholesale market and commodity related costs to customers. These costs are passed through and not part of a utility's underlying costs to serve its customers. Accordingly, the prices of these services are not considered by the OEB in its review of a consolidation application.

5. Rate-Making Considerations Associated with Consolidation Applications

The OEB's policies on rate-making matters associated with consolidation in the electricity distribution sector are set out in two reports of the OEB. The first report titled "*Rate-making Associated with Distributor Consolidation*" issued on July 23, 2007 (2007 Report) was supplemented by the 2015 Report, issued under the same name, as previously indicated.[5]

This section of the Handbook consolidates information that is provided in these two reports and identifies the key rate-making considerations expected to arise in

[5] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015

consolidation transactions. Applicants are, however, encouraged to review both reports in preparing their applications for both the consolidation transaction and subsequent rate application.

Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g. a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review of a utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers.

Rate-Setting Policies

The rate making considerations relating to consolidation that applicants and parties need to be aware of are:

- Deferred Rebasing
- Early Termination of Pre-Consolidation Rate-Setting term
- Early Termination or Extension of Deferred Rebasing Period
- Rate Setting During Deferred Rebasing Period
- Off Ramp
- Earnings Sharing Mechanism
- Incremental Capital Investments During Deferred Rebasing Period
- Future Rate Structures
- Deferral and Variance Accounts

Deferred Rebasing

The setting of rates for a consolidated entity using a cost of service methodology or a Custom Incentive Rate-setting method (both referred to in this document as rebasing of rates) involves a detailed assessment by the OEB of a utility's underlying costs. A consolidated entity is required to file a separate application with the OEB under Section 78 of the OEB Act for a rebasing of its rates. This typically takes place at some point in time following the OEB's approval of a consolidation.

To encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any achieved savings. The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. The 2015 Report also states that consolidating entities deferring rebasing for up to five years may do so under the policies established in the 2007 Report.[6] The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period subject to the minimum requirements set out below.

While the OEB has determined that allowing a longer deferred rebasing period is appropriate to incent consolidation, there must be an appropriate balance between the incentives provided to utilities and the protection provided to customers. The OEB will therefore require consolidating distributors to identify in their consolidation application the specific number of years for which they choose to defer. It is not sufficient for applicants to state that they will defer rebasing for <u>up to</u> 10 years. Distributors must select a definitive timeframe for the deferred rebasing period. This will allow the OEB to assess any proposed departure from this stated plan.

In addition, distributors cannot select a deferred rebasing period that is shorter than the shortest remaining term of one of the consolidating distributors. Therefore, a consolidated entity can only rebase when:

i) The selected deferred rebasing period has expired, and
ii) At least one rate-setting term of one of the consolidating entities has also expired.

Early Termination of Pre-Consolidation Rate-setting Term

At the time distributors first enter into a consolidation transaction, consolidating distributors may be on any one of the rate setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates.

A consolidated entity may apply to the OEB to rebase its rates as a consolidated entity through a cost of service or Custom IR application following the expiry of the original rate-setting term of at least one of the consolidating entities and once the selected deferred rebasing period has concluded. If, however, a consolidated entity wishes to rebase its rates prior to the end of the pre-consolidation rate-setting term of the distributor that has the earliest termination date, the consolidated entity must demonstrate the need for this “early rebasing” as part of the early rebasing application.

[6] Report of the Board on Rate-making Associated with Distributor Consolidation, July 23, 2007

The OEB established its approach to early rebasing in a letter dated April 20, 2010 and reiterated it in the RRFE. The OEB expects a distributor that seeks to have its rates rebased earlier than scheduled to clearly demonstrate why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remaining years of its current rate term.

Early Termination or Extension of Selected Deferred Rebasing Period

The OEB considers that consolidations can provide for greater efficiencies and benefits to customers and is committed to reducing regulatory barriers to consolidations. The OEB has allowed for a deferred rebasing period to eliminate one of the identified barriers to consolidations. The OEB remains of the view that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. That being said, when a consolidating entity has opted for a deferred rebasing period, it has committed to a plan based on the circumstances of the consolidation. For this reason, if the consolidated entity seeks to amend the deferred rebasing period, the OEB will need to understand whether any change to the proposed rebasing timeframe is in the best interest of customers.

Distributors who subsequently request a shorter deferred rebasing period than the one that has been selected (and where at least one of the pre-consolidation rate-setting plans has expired) will be required to file rationale to support the need to amend the previously selected deferred rebasing period. Similarly, a consolidated entity having selected a deferred rebasing period less than 10 years, that seeks to extend its selected deferred rebasing period must explain why this is required.

Rate Setting during Deferred Rebasing Period

Under the OEB's RRFE, there are three rate-setting options: Price Cap Incentive Rate-Setting (Price Cap IR or PCIR), Custom Incentive Rate-Setting (Custom IR or CIR) and Annual Incentive Rate-Setting Index (Annual IR Index or AIRI). The term of the Price Cap IR and Custom IR options is normally five years. The Annual IR Index option has no specific term.

Consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates. The 2015 Report clarified how rates will be set for a distributor who is a party to a consolidation transaction during any deferred rebasing period after the distributor's original incentive rate-setting plan has concluded:

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on the Annual IR Index will continue to have rates based on the Annual IR Index, until it selects a different rate-setting option.

Table 1 below illustrates six potential scenarios for rate-setting during the deferred rebasing period, assuming the consolidation of two distributors. The table also sets out the conditions that must be met by a consolidated entity that elects to rebase its rates. While Table 1 is intended to illustrate a situation of two consolidating distributors, the OEB is aware that future consolidations may involve several consolidating distributors as well as the possibility of multiple successive consolidation transactions by a single consolidated entity. For unique circumstances, the OEB may need to assess the rate-setting proposals on a case by case basis.

Table 1 - Rate-Setting Options During the Deferred Rebasing Period

Going in Rates
As of the date of the closing of the transaction. Assumes two distributors.

	Both on PCIR	One on PCIR and one on CIR	Both on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	LDC on PCIR continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.	Continue with current plans. Once each term expires, each LDC will move to PCIR for the remaining years of the chosen deferred rebasing period.
	OR	OR	OR
Rebasing Options	Rebase as a consolidated entity following the expiration of one of the entities' term and once the selected deferred rebasing period has concluded.	LDC on PCIR continues on current plan. If its term expires in advance of the expiration of the other LDC's CIR term the consolidated entity may rebase once the selected deferred rebasing period has concluded.	Continue with current plans. Once the earlier of the two terms expires the consolidated entity may rebase once the selected deferred rebasing period has concluded.
		OR	
		If the term for the LDC on CIR expires first, the consolidated entity may rebase following the expiration of the CIR term and once the selected deferred rebasing period has concluded.	

	One on PCIR and one on AIRI	Both on AIRI	One on AIRI and one on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	Continue with current plans for chosen deferred rebasing period.	LDC on AIRI continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.
	OR	OR	OR
Rebasing Options	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.

Off Ramp

As set out in the OEB's RRFE, each incentive rate-setting method includes an annual return on equity (ROE) dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated by the OEB. The OEB requires consistent, meaningful and timely reporting to effectively monitor utility performance and determine if expected outcomes are being achieved. The OEB's performance monitoring framework allows the OEB to take corrective action if required, including the possible termination of the distributor's rate-setting method and requiring the distributor to have its rates rebased.

The dead band of ±300 basis points on ROE continues to apply to utilities who have deferred rebasing due to consolidation. For utilities who defer rebasing up to five years, the OEB may initiate a regulatory review if the earnings are outside of the dead band. For utilities deferring rebasing beyond five years, an earnings sharing mechanism is required above ±300 basis points as discussed in the next section.

Earning Sharing Mechanism (ESM)

Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.[7] The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

In the 2015 Report, the OEB determined that under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report.

There are numerous types and structures of consolidation transactions, and there can be significant differences between utilities involved in a transaction. The ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the

[7] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015, p.6

deferred rebasing period. For example, a large distributor that acquires a small distributor may demonstrate the objective of consumer protection by proposing an ESM where excess earnings will accrue only to the benefit of the customers of the acquired distributor.

Incremental Capital Investments during Deferred Rebasing Period

The Incremental Capital Module (ICM) is an additional rate-setting mechanism under the Price Cap IR option to allow adjustment to rates for discrete capital projects. The details of the mechanism are described in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued on September 18, 2014 and a supplemental report with further enhancements will be issued in January 2016.

The ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.

The 2015 Report sets out that a distributor who is in the midst of the Custom IR plan at the time of the transaction and who consolidates with an entity operating under a Price Cap IR or an Annual IR Index may only apply for an ICM for investments incremental to its Custom IR plan. The rules that apply to a specific rate-setting method continue to apply even following a consolidation of distributors. To be specific, an ICM would not be available for the rates in the service area for which the Custom IR plan term applies until the term of the Custom IR ends and Price Cap IR applies. Materiality thresholds for the ICM will be calculated based on the individual distributors' accounts and not that of the consolidated entity.

Future Rate Structures

A consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time it files its rebasing application. Distributors are not required to file details of their rate-setting plans, including any proposals for rate harmonization, as part of the application for consolidation. These issues will be addressed at the time of rate rebasing of the consolidated entity.

A rate harmonization plan can propose the approach and timeline for harmonizing rate classes or provide rationale for why certain rate classes should not be harmonized based on underlying differences in cost structures and drivers. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. However, the OEB expects that whichever option is adopted, rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.

Deferral and Variance Accounts

Where a transmitter or distributor has accumulated balances in a deferral or variance account, the question of who should pay for, or receive credits from the clearance of these balances is relevant to the consolidation only if it affects the financial viability of the acquiring utility or consolidated entity. A decision on the actual clearance of deferral or variance accounts would be part of a rate application, not an application seeking approval for consolidation.

INDEX: Schedule 1 – Relevant Sections of the OEB Act

Section 86 of the OEB Act

Change in ownership or control of systems

86. (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or

(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a transmitter or distributor or of a corporation that owns securities in a transmitter or distributor. 2002, c. 1, Sched. B, s. 9 (1).

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

- (a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or
- (b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2).

INDEX: Schedule 2 – Filing Requirements for Consolidation Applications

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Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements For Consolidation Applications

January 19, 2016

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Filing Requirements for Consolidation Applications

1. Introduction

Completeness and Accuracy of an Application

These filing requirements provide direction to applicants in preparing a consolidation application. It is expected that applicants will file applications consistent with the filing requirements. Applications must be accurate, and information and data presented must be consistent throughout the application. If an application does not meet all of these requirements, or if there are inconsistencies identified in the information or data presented, the OEB may put the application in abeyance, unless satisfactory justification for missing or inconsistent information has been provided or until revised satisfactory evidence is filed. If circumstances warrant, the OEB may require an applicant to file evidence in addition to what is identified in the filing requirements. An applicant should only file information that is relevant to the OEB's statutory objectives in relation to electricity. Applicants should refer to the Handbook on the OEB's expectations and approach to reviewing consolidation applications.

Certification of Evidence

An application filed with the OEB must include a certification by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his or her knowledge.

Updating an Application

When material changes or updates to an application or other evidence are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure* (the Rules). When changes or updates are contemplated in later stages of a proceeding, updates should only be done if there is a material change to the evidence already before the OEB. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part(s) revised.

Interrogatories

Interrogatories are an important part of the process of clarifying and testing evidence, however they must focus on issues that are relevant to the OEB's decision. Excessive interrogatories introduce inefficiency into the application process. The OEB advises applicants to consider the clarity, completeness and accuracy of their evidence and refer to the Handbook for what will be considered or not in order to reduce the need for interrogatories. The OEB also advises parties to carefully consider the relevance and materiality of information before requesting it through interrogatories. Parties must consult Rules 26 and 27 of the OEB's *Rules of Practice and Procedure*, April 24, 2014 revision, for additional information on the filing of interrogatories and responses and matters related to such filings.

Confidential Information

The OEB relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The OEB's expectation is that applicants will make every effort to file material contained in an application publicly and completely, and without redactions in order to ensure the transparency of the review process. The OEB's Rules and the *Practice Direction on Confidential Filings* (the Practice Direction) allow for applicants and other parties to request that certain evidence be treated as confidential. Where such a request is made, parties are expected to review and follow the Practice Direction. This includes assessment of the relevance of any requested document prior to filing it with the OEB and requesting confidential treatment. There is no requirement or expectation on applicants to file documents that are out of scope of the areas the OEB has determined are relevant to its consideration of a consolidation application as defined in the Handbook.

2. Information Required of Applicants

The OEB expects an application for consolidation to have the following components:

2.1 Exhibit A: The Index

	Content	Described in
Exhibit A	Index	2.1
Exhibit B	The Application	2.2
	Administrative	2.2.1
	Description of the Business of the Parties to the Transaction	2.2.2
	Description of the Transaction	2.2.3
	Impact of transaction on the OEB's statutory objectives	2.2.4
	Rate considerations for consolidation applications	2.2.5
	Other Related Matters	2.2.6

2.2 Exhibit B: The Application

2.2.1 Administrative

This section must include the formal signed application, which must incorporate the following:

- Legal name of the applicant or applicants
- Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses
- Legal name of the other party or parties to the transaction, if not an applicant
- Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses
- Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants

2.2.2 Description of the Business of the Parties to the Transaction

This section of the application requires the applicant to provide the following information on the parties to the proposed transaction:

- Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity.

- Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries.

- Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

- Describe the proposed geographic service area of each of the parties after completion of the proposed transaction.

- Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

- If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction. The OEB will, in the absence of exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility.

2.2.3 Description of the Proposed Transaction

This section of the application requires the applicant to provide the following:

- Provide a detailed description of the proposed transaction.
- Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the *Ontario Energy Board Act, 1998*.
- Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.
- Provide all final legal documents to be used to implement the proposed transaction.
- Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction.

2.2.4 Impact of the Proposed Transaction

In reviewing an application, the OEB will apply the no harm test as outlined in the Handbook. Applicants are required to provide the following evidence to demonstrate the impact of the proposed transaction with respect to the OEB's first two statutory objectives.

Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

- Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.
- Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction.

- Provide a comparison of the OM&A cost per customer per year between the consolidating distributors.

- Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

- Describe how the distribution or transmission systems within the service areas will be operated.

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

- Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative).

- Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.

- Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.

- If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.

- Provide details of the financing of the proposed transaction.

- Provide financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

- Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.

2.2.5 Rate considerations for consolidation applications

Applicants are required to provide the information with respect to the following rate making considerations relating to consolidation:

- Indicate a specific deferred rate rebasing period that has been chosen.
- For deferred rebasing periods greater than five years:
  - Confirm that the ESM will be as required by the 2015 Report and the Handbook
  - If the applicant's proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor

2.2.6 Other Related Matters

Applicants have, in previous consolidation applications, made the following additional requests to the OEB which have formed part of the OEB's determination of a consolidation application:

a) Implementation of new or the extension of existing rate riders
b) Transfer of rate order and licence
c) Licence amendment and cancellation
d) Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB
e) Approval to use different accounting standards for financial reporting following the closing of the proposed transaction

Applicants are required to provide justification for these types of requests and for any other requests for which a determination is being sought from the OEB as part of a consolidation application.

- End of document –

ONTARIO ENERGY BOARD

Ontario

EB-2014-0138

Report of the Board

Rate-Making Associated with Distributor Consolidation

March 26, 2015

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A. INTRODUCTION

The Ontario Energy Board's renewed regulatory framework is a comprehensive performance based approach to regulation. The framework sets expectations that electricity distributors will seek out efficiencies to increase productivity and manage costs. The OEB issued a letter on February 11, 2013, announcing an initiative to assess how the OEB's regulatory requirements for electricity distributors may affect the ability of distributors to realize operational or organizational efficiencies (EB-2012-0397).

Consultations with stakeholders took place in early 2013 to review potential changes to the OEB's regulatory requirements that may facilitate efficiency improvements. On November 4, 2013, the OEB issued a letter, announcing that it would proceed with a further review of its policies related to service area amendments ("SAA") and rate-making associated with merger, amalgamation, acquisition and divestiture ("MAADs") transactions.

The report of the Ontario Distribution Sector Review Panel, issued in December 2012, set out a vision for consolidation resulting in the less costly and more efficient delivery of electricity, with a predicted cost savings of $1.2 billion over the next ten years. When the Minister of Energy responded to the Panel's report, he indicated that he expected that the sector would find ways to achieve those savings through more efficient service delivery, including negotiated consolidations. This view was carried forward in the government's December 2013 Long Term Energy Plan ("LTEP"), where it is stated that the government expects electricity distributors to pursue innovative partnerships and transformative initiatives that will result in savings for electricity ratepayers.

On March 31, 2014, the OEB issued a OEB staff Discussion Paper (the "Discussion Paper") providing background on the current policies, summarizing stakeholder input received in relation to those policies, and setting out questions for stakeholder comment with respect to potential changes to those policies.

On November 13, 2014, the Advisory Council on Government Assets issued its findings which included the view that consolidation was needed to encourage modernization of the electricity distribution system.

After considering the government's policy expectations, the results of the consultations, and the OEB's own expectations that the distribution sector should continue to seek out efficiencies especially through consolidation, **the OEB has concluded that it will proceed at this time with amendments to its rate-making policy associated with electricity distributor consolidation.**

This Report sets out the OEB's amendments to its rate-making policy for electricity distributors following a MAADs transaction.

The OEB has identified two specific policy matters that it intends to address at this time:

- The duration of the deferral period for rebasing following the closing of a MAADs transaction; and,

- A mechanism for adjusting rates to reflect incremental capital investments during the deferred rebasing period.

The amendments to the OEB's policy in relation to each of these matters are discussed below. The OEB has also provided clarification regarding the incentive rate mechanism that will apply to a distributor during a rebasing deferral period.

B. DEFERRAL PERIOD FOR RATE REBASING

Consolidating distributor(s) may elect to defer rebasing for a period of up to 10 years after the closing of the transaction.

Consolidating entities that elect a re-basing period of up to five years after the closing of the transaction may do so as set out under the current policy[1].

Consolidating entities may also apply for an extended rate rebasing deferral period of up to 10 years. For the extended period (i.e. – the period between year 5 and year 10), the OEB will require the consolidating entity to implement an earnings sharing mechanism. The earnings sharing split shall be a 50:50 sharing with customers where the return on equity for the consolidated distributor is greater than 300 basis points above the allowed rate of return for the consolidated distributor.

[1] *Report of the Board regarding Rate-Making Policies Associated with Distributor Consolidation*, issued July 23, 2007.

The OEB's current policy with regards to rate issues associated with MAADs transactions was developed in 2007, and is found in its *Report of the Board regarding Rate-making Policies Associated with Distributor Consolidation* (the "2007 Policy").

Under the 2007 Policy, when a distributor applies for approval of a MAADs transaction it may propose to defer rebasing of the rates of the consolidated entity for up to five years from the date of the closing of the transaction. The purpose of this policy is to allow the net savings of a consolidation to accrue to a distributor's shareholder(s) for an extended period. The OEB recognized that providing a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction is an important factor in a utility's consideration of the merits of a given consolidation initiative. The five-year period was selected based on a review of practice in other jurisdictions, and taking into consideration the fact that the maximum duration of any rate plan for distributors at the time was three years.

The principal focus of distributor comments received both through the 2013 consultation and the responses to the Discussion paper, was concern regarding the length of time over which rebasing of a consolidated entity's rates can be deferred.
It is the view of distributors that the current policy may not provide sufficient time to achieve the savings and efficiency gains necessary to enable the recovery of transaction costs. Distributors expressed the view that the risk for shareholders of not recovering transaction costs is a significant impediment to consolidation.

Distributors explained that the transition and integration costs of a MAADs transaction, although largely incurred upfront can continue for two to four years following the completion of the transaction. Whereas efficiency gains and savings resulting from the transaction will not start to be realized until the transaction is completed and the new entity has begun to operate. Distributors indicated that given the nature and timing of these costs and savings, annual net benefits (operational costs less transition and integration costs) are in many cases negative during the first two to four years. Therefore, it may take anywhere from six to ten years to reach a break-even point, where the cumulative savings exceed the cumulative acquisition and integration costs.

Distributors therefore suggested that greater flexibility in terms of the rebasing time frame and the ability to retain any achieved savings for a longer deferral period will provide encouragement to those who may be interested in pursuing consolidation opportunities.

Representatives of consumers expressed the view that savings that result from a MAADs transaction should be shared equitably between the distributor's ratepayers and the distributors' shareholders. There are concerns that extending the deferral period will provide an opportunity for shareholders to retain more savings than those necessary to recover costs, which may result in a windfall for shareholders at the expanse of ratepayers. Ratepayer representatives suggested that for the rebasing to be deferred, other benefits for consumers would need to be provided, either in the form of new services or, of a certainty of savings that would continue after the rebasing.

Consumer representatives also suggested that allowing a distributor to choose its own time for rebasing may not benefit consumers. A distributor that is able to cut costs could delay rebasing to keep its savings, but a distributor who experiences higher costs would rebase immediately in order to pass those incremental costs on to ratepayers. Such an approach would relieve the shareholders of risk at the expense of the ratepayers. There were also concerns expressed that allowing shareholders to recover additional savings may reduce the market forces that lead to efficient consolidations.

OEB Policy

The OEB believes that the decision to extend the deferred rebasing period for distributors who are party to a MAADs transaction supports the OEB's own expectations, as well as those of the government, that the distribution sector should continue to seek out efficiencies, especially through consolidation.

The OEB has determined that providing an extension of the allowed deferral period to up to 10 years after the closing of the transaction, would address distributors' key concern about the 2007 policy; would reduce the risk of a MAADs transaction, which may encourage more consolidation; and would provide distributors with the flexibility to manage their own, unique circumstances.

The OEB believes that the requirement for the MAAD's application to include an earnings sharing mechanism (ESM) will address ratepayer concerns that the accumulated savings could amount to a windfall for shareholders.

The ESM would operate during the term of the extended deferred rebasing period. (i.e. – for any extended periods beyond the initial five year deferral period). The ESM would be in keeping with the OEB's current incentive rate-making policy under which a regulatory review may be initiated if a distributor's annual reports show performance outside of the +/- 300 basis points earnings dead band. In the case of a MAADs transaction, if the consolidated entity's actual ROE rose above the 300 basis points over the allowed ROE, the ESM will be implemented. The ESM for the purpose of the extended period will employ a 50:50 sharing with customers of excess earnings. This sharing provides for the shareholders to continue to recover transaction costs while ensuring customers of the consolidated entity will benefit from the efficiencies and savings the new distributor has achieved.

During the deferred re-basing period, whether up to five years or beyond five years, once the original incentive rate-making period of one of the distributors who are party to the transaction expires, the consolidated entities may apply to the OEB for cost-of-service rate setting for the consolidated entity. The OEB believes that it is in the best interest of consumers to have consolidating entities operate as one entity as soon as possible after the MAADs transaction. The consolidated entity application will allow the OEB to establish rates that reflect the efficiencies from the consolidation transaction. Therefore, there is no requirement for the consolidated entity to wait until the deferred re-basing period is completed to apply to the OEB for re-basing.

The OEB also notes that despite the ability for consolidated entities to extend the rate re-basing period, all other regulatory requirements, including the requirement to file Distribution System Plans every five years remain in effect.

The OEB will continue to make use of its monitoring tools, available through distributor's annual reporting requirements, to determine whether the results of MAADs transactions for consumers and the industry warrant additional consumer protection measures. If so, future changes to the policy may be considered.

C. INCREMENTAL CAPITAL INVESTMENTS DURING THE DEFERRAL PERIOD

The Incremental Capital Module ("ICM") will now be available to consolidating entities during the rate rebasing period.

When developing the 2007 Policy, the OEB considered the issue of how to deal with capital investments during the deferred rebasing period. The OEB determined that it would not establish a mechanism to adjust for capital investment during the deferred rebasing period, and suggested that the matter should be considered as part of the next incentive regulation review.

Subsequently, in its September 17, 2008, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, the OEB established the Incremental Capital Module ("ICM") as the mechanism by which distributors could seek funding for extraordinary and unanticipated capital investments (but not normal expected investments) during the incentive regulation term. Of the three RRFE rate-setting options, the ICM application is available only to distributors that have chosen the Price Cap IR.

Distributors have indicated that while an extended deferral period may allow for the recovery of costs, the treatment of capital investments during this period may reduce the benefits of the extension. Some of the distributors suggested that few, if any, distributors would be able to operate over an deferred rebasing period without incorporating normal and expected capital expenditures into rate base. Their concern is that, if capital additions cannot be incorporated into rate base, the shareholder's rate of return would diminish and there would be impacts on financing for capital investments.

Distributors also expressed concern that they will be forced to choose between early rate-rebasing to address capital spending, or deferred rebasing in order to enhance the viability of a MAADs transaction. In their view, this may have a dampening effect on consolidation because the recovery of transaction costs will come at the expense of foregoing the recovery of capital expenditures. By contrast, if distributors who are considering a MAADs transaction know that they have the ability to apply to the OEB for the inclusion of on-going capital investments into rate base during the deferred rebasing period, they may be more willing to consider consolidation.

Stakeholders representing consumers suggested that the existing incentive rate-setting mechanisms already provide for the funding of capital, and that any additional mechanisms may result in an over-recovery from the consumer and could possibly reward underperforming distributors. Stakeholders who disagree with the proposed approach suggest that there is a risk that using a modified ICM would impact ratepayers worse than if no merger took place. Some parties have also suggested that the proposed approach would go against objective of the Annual IR which provides distributors with opportunity for increased rates, while protecting ratepayers with low rate stable increases. They are concerned that the proposal would turn Annual IR into "Selective IR", in which the full impacts of a utility's costs would be deliberately ignored by the OEB for as long as the utility wanted. Other stakeholders have suggested that if a distributor has the need to incorporate capital investments into rate base, it should go through a Custom IR.

On September 18, 2014, the OEB issued the Report of the Board, New Policy Options for Funding of Capital Investments: The Advanced Capital Module. In this Report, the OEB clarified that the opportunity for requests for review and approvals of incremental capital during an IR term will be maintained for projects that were unanticipated at the time of the development of a distributors' system plan, and/or for projects anticipated but for which sufficient rationale was not available at the time of the system plan to establish need and prudence. The ability to apply for an ACM remains only with those distributors who are under the Price Cap IR.

On page 15 of the September 18th Report, the OEB stated the following:

> *"The Board is of the view that the availability of incremental capital funding during the IR term should no longer be limited to non-discretionary projects. Any discrete project (discretionary or otherwise) adequately supported in the DSP (Distribution System Plan) is eligible for ACM funding subject to capital funding availability flowing from the formula results. The same approach shall apply going forward to new projects proposed as ICMs during the Price Cap IR term." (emphasis added)*

OEB Policy

The OEB believes that the clarification set out in the September 18th Report establishes that a distributor may now apply for an ICM that includes normal and expected capital investments. This clarification of policy should address the need of those distributors who may not consider entering into a MAADs transaction due to concerns over the ability to finance capital investments.

The one remaining limitation is that the ability to apply for an ICM continues to be limited to those distributors under the Price Cap IR, and it is anticipated that distributors considering a MAADs transaction will be operating under one or more of the other rate setting options. The question that needs to be addressed, in the OEB's view, is the situation where one or more distributors that are part of a MAADs transaction are operating under Custom IR or Annual IR and the impact of the ICM policy for the combined entity.

As discussed in the next section, distributors who are part of a MAADs transaction and have their Custom IR plan expire during the deferred rebasing period, would transition to the Price Cap IR. Once the distributor has made this transition, it will have the option to utilize the ICM consistent with the OEB's existing approach to incentive regulation.

Distributors who are in the midst of their Custom IR plan at the time of the MAADs transaction and consolidate with an entity operating under a Price Cap IR or an Annual IR may only apply for an ICM that relates to investments incremental to its Custom IR plan.

The OEB believes that its proposal to allow a combined entity who is operating under an Annual IR plan to make use of the ICM is reasonable, effective and will address distributor's concerns over capital investment during a deferred rebasing period which may encourage consolidation efforts.

The OEB notes that distributors proposing amounts for recovery by way of an ICM must be assessed by the OEB through a hearing and must meet the tests of materiality, need and prudence. Therefore, ratepayers continue to be protected under the OEB's proposed approach. Further the OEB is of the view that part of a review of any ICM requests by the combined entity, where one of the combined distributors was on a Custom IR, would include a test to determine whether the requested amounts for ICM recovery were separate from the amounts that had been included in the distributor's Custom IR plan.

In regards to making an application for an ICM, the materiality thresholds for purposes of the ICM policy shall be calculated based on the individual distributor's accounts, i.e. depreciation expense, and not the consolidated entity's.

D. INCENTIVE MECHANISM DURING THE DEFERRAL PERIOD

Under its renewed regulatory framework, the OEB has established three rate-setting approaches for distributors. A distributor may now choose amongst: Custom IR, Price Cap IR, and Annual IR.

As there are now three rate-setting options available to distributors, there will be potential for parties to a MAADs transaction to be on different rate options at the time of consolidation. The question that arises is which plan would apply to a distributor where its current approved rate plan ends during the deferred rebasing period

Distributor groups have suggested the consolidated entity should be allowed to continue under the existing Custom IR plan during the deferred re-basing period. Ratepayer groups believe the consolidated entity should undergo a Custom IR as soon as possible, in order to ensure any savings are properly shared.

Continuing to operate under a Custom IR where this is a form of rate adjustment is not feasible as the OEB has not approved rates for that distributor beyond the initial five years. Also, requiring a merged entity to undergo a Custom IR immediately would be counter to the intent of the 2007 policy as the consolidated entity would immediately lose any efficiency savings it expected to pay for transaction costs.

OEB Policy

The OEB wishes to clarify which incentive rate plan would apply to distributors who are party to a MAADs transaction during any deferred rebasing period after the distributors original IR plan is complete.

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap adjustment mechanism during the remainder of the deferral period. This approach is consistent with the current policy.

- A distributor on the Annual IR, whose plan expires, would continue to have rates based on the Annual IR index, until it selects a different option. This approach is consistent with the current policy, as there is no set rate rebasing timeframe under the Annual IR.

- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism, during the remainder of the deferral period.

The OEB believes that its proposal is in keeping with the original 2007 Policy and RRFE's focus on reducing regulatory burden and costs. This proposal will also assist in the efficient implementation of a deferred rebasing period, which in turn will support the objective of finding efficiencies through consolidation.

E. NEXT STEPS

The policy changes made by the OEB are intended to encourage efficient and beneficial consolidation transactions within the electricity distribution sector. The OEB has made changes that reflect concerns of the industry with the current policy while ensuring consumers will benefit through earlier rebasing or sharing of savings.

Some of the policy changes outlined in the Report will require amendments to be made to the MAADs filing requirements. In the case of the policy statements that have been made in the Report, these are summarized below and are considered amendments to the existing policies.

1. Allow consolidating entities to choose a deferred rebasing period of up to 10 years after the closing of the transaction. Those consolidating entities that elect a re-basing period of only up to five years may do so as set out under the current policy.

2. Those consolidating entities requesting a deferred re-basing period of greater than five years will be required to present the OEB with an ESM plan that would be implemented if the consolidated entity's ROE was greater than 300 basis points above the allowed ROE as set out under the incentive regulation policy. The ESM will be based on a 50:50 sharing of excess earnings with consumers.

3. Distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the Incremental Capital Module during the deferred rebasing period.

4. Distributors who are party to a MAADs transaction that are on the Price Cap IR at the time of consolidation will to continue to have their rates adjusted under the same mechanism until rebasing. In the case of distributors on the Annual IR the consolidated distributor would continue to operate under the Annual Index option unless and until it selects a different option. Distributors whose Custom IR plan expires during the deferred rebasing period will move to the Price Cap IR.

Ontario Energy Board

EB-2010-0059

Board Policy:

Framework for Transmission Project Development Plans

August 26, 2010

Table of Contents

1 Introduction

1.1 Purpose

This document sets out the policy of the Ontario Energy Board for a framework for new transmission investment in Ontario, in particular with regard to transmission project development planning. The policy describes how project development planning will work in conjunction with existing Board processes for licensed transmitters.

This policy is the end result of a consultation on facilitation of the timely and cost effective development of major transmission facilities that may be required to connect renewable generation in Ontario. The goal is the implementation of a process that provides, among other things, greater regulatory predictability in relation to cost recovery for development work. The Board believes that this policy will:

- allow transmitters to move ahead on development work in a timely manner;
- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

This introduction includes a background of the issue and history of the consultation. Section 2 of this paper describes principles and goals that the Board used to evaluate staff's proposal and the stakeholder comments in order to devise the final policy. Section 3 outlines the licensing process for transmitters intending to participate in the Board designation process. Section 4 outlines the process to be followed in designating a transmitter to undertake development work on enabler facilities and network expansions including: the method for identification of eligible projects; the trigger for the process; the decision criteria for designation and the filing requirements intended to solicit the information; and the implications of approval of a plan.

The Filing Requirements for Transmission Project Development Planning are published under separate cover on the Board's website[1].

[1] http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms

1.2 Background

As a consequence of the passage of the *Green Energy and Green Economy Act, 2009* ("GEA"), there has been enormous interest in connecting renewable generation to both distribution and transmission systems. However, the ability of existing or approved transmission facilities in Ontario to accommodate more generation is limited. Based in part on the number of applications for contracts under the Feed-in Tariff ("FIT") program, the Board understands that significant investment in transmission infrastructure will be required to accommodate current FIT applicants as well as any future renewable generation projects.

Advance knowledge of the location and timing of new infrastructure should allow developers to site prospective generation projects along anticipated transmission corridors in order to reduce overall connection costs. Developers should be able to anticipate development of the system and plan its construction schedule to coincide with economic connection.

Board staff met with licensed transmitters to discuss how the transmission planning process might work. Transmitters have indicated the need for a clear process, including an articulation of the overall transmission planning, approval and rate recovery framework.

On April 19, 2010, the Board released a staff Discussion Paper[2] for comment by stakeholders. Board staff's proposals built on earlier work by the Board with respect to transmission connection cost responsibility and in particular on the process that the Board has developed for "enabler" transmission facilities. Staff's proposals focused specifically on development work for projects identified by the Ontario Power Authority ("OPA") as it assesses transmission investments associated with the connection of generation under the FIT program.

The Board received 27 comments[3] on staff's proposals from entities representing a variety of stakeholder groups: current Ontario transmitters and those who would be new to Ontario; generator groups; ratepayer groups; special interest groups; one distributor; the IESO and the OPA.

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[2] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2010-0059/Staff_paper_Tx_Project_Dev_20100419.pdf

[3] Complete text of stakeholder comments is available at the Board's website at: http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Transmission+Project+Development+Planning/Transmission+Project+Development+Planning

2 Board Principles

The Board's goal in developing a policy for transmission project development planning is to facilitate the timely development of the transmission system to accommodate renewable generation.

In developing this policy, the Board is guided by its objectives in relation to the electricity sector under the *Ontario Energy Board Act, 1998* (the "OEB Act"). Of particular relevance in this instance are the objectives of protecting the interests of consumers with respect to price, quality and reliability of electricity supply and facilitating economic efficiency in the development of the transmission system including the maintenance of a financially viable electricity industry. Also important in this instance is the new objective of the Board to promote the use of energy from renewable generation sources.

The Board has previously identified the principles it uses in fulfilling its objectives in transmission policy[4]: economic efficiency; regulatory predictability; and administrative efficiency. The Board has reviewed the staff proposal and the stakeholder comments with the goal of fulfilling its objectives and promoting these principles.

Within the context of transmission investment policy, economic efficiency can be understood to mean achieving the expansion of the transmission system in a cost effective and timely manner to accommodate the connection of renewable energy sources. The Board believes that economic efficiency will be best pursued by introducing competition in transmission service to the extent possible within the current regulatory and market system.

Regulatory predictability allows proponents to understand how and on what basis regulatory decisions are likely to be made. The Board achieves this through policy statements and guidance to the industry and through transparent processes leading to consistency in the determinations it makes and the orders that it issues. Transmission planning is an ongoing procedure. The Board intends to put in place a transmission investment policy and project development planning process that is robust enough to provide consistency of process through many cycles of planning.

Administrative efficiency relates to the level of effort required from the perspective of proponents and other interested parties for effective participation in processes. In

[4] Most recently in the Staff Discussion Paper: Generation Connections for Transmission Connection Cost Responsibility Review (EB-2008-0003) available at:
http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0003/Staff_Discussion_Paper_20080708.pdf

devising this process, the Board has sought to avoid duplication and unnecessary effort for transmitters, Board staff and other stakeholders.

Taken together, regulatory predictability and administrative efficiency should facilitate investment, planning and decision-making by transmission proponents and should help them to manage business risks.

These aims are consistent with broader movements in energy regulation around the world. In particular, the United Kingdom and the United States are both currently consulting on policy changes along similar lines.

Ofgem in the U.K. is proposing[5] to evolve its regulatory framework to the RIIO model: Revenue set to deliver strong Incentives, Innovation and Outputs. Ofgem acknowledges that changes are needed to "meet the demands of moving to a low carbon economy…whilst maintaining safe, secure and reliable energy supplies"[6]. Ofgem's new proposed framework to deliver long-term value for money for network services includes involving third parties in design, build, operation and ownership of large, separable enhancement projects. Third party participation is to be considered where long-term benefits, especially for new technologies, new delivery solutions and new financing arrangements, are expected to exceed long-term costs. Ofgem would be responsible for any competitive process.

FERC in the U.S. released a Notice of Proposed Rulemaking on June 17, 2010.

> "With respect to transmission planning, the proposed rule would (1) provide that local regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighbouring transmission planning regions with respect to interregional facilities ; and (3) remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[7]

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[5] "Regulating energy networks for the future: RPI-X@20 Recommendations" available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=RPI-X@Recommendations.pdf&refer=Networks/rpix20/ConsultDocs

[6] Ibid: Executive Summary.

[7] The Notice of Proposed Rulemaking: Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities (Docket No. RM10-23-000) by the Federal Energy Regulatory Commission, pg 1. available at: http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf .

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0140

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

BEFORE: Cynthia Chaplin
Presiding Member and Vice-Chair

Cathy Spoel
Member

PHASE 1 DECISION AND ORDER

July 12, 2012

INTRODUCTION

On February 2, 2012, the Ontario Energy Board issued notice that it was initiating a proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line. The Board assigned File No. EB-2011-0140 to the designation proceeding. Seven transmitters registered their interest in the designation process.

Additional criteria, other than First Nation and Métis issues

The submissions of parties contained several proposals for additional criteria. The Board will not add a specific additional criterion relating to facilitating competition and new entrants. The facilitation of competition and the encouragement of new entrants to transmission in the province was part of the context for the Board's Policy, and are being recognized by the initiation of this designation process. Any applicant who wishes to bring evidence of any advantage to Ontario ratepayers of the designation of a new entrant for this project is invited to do so as part of the "other factors" criterion.

The Board finds that there is no need to create additional criteria related to the provision of socio-economic benefits, the ability to mitigate environmental impacts, regulatory expertise, or location-specific experience. Each of these issues will be considered to some degree under the criteria "technical capability" and "organization". The Board notes that mitigation of environmental and socio-economic impacts is considered as part of the Environmental Assessment process. The Board will not require evidence of an applicant's ability to mitigate these impacts, but will require evidence of the applicant's ability to successfully complete regulatory processes similar to Ontario's Environmental Assessment process.

With respect to regulatory expertise, the Board will require evidence under the criterion "technical capability" of an applicant's ability to successfully complete the regulatory processes necessary for the construction and operation of the line.

The Board will not necessarily favour experience in Ontario over experience in other jurisdictions. It is important that the designated transmitter be fully capable of constructing and operating an electricity transmission line that meets the needs identified by the OPA and the Independent Electricity System Operator ("IESO") in the location proposed in the transmitter's plan. However, the experience necessary to achieve this capability may have been gained in other jurisdictions. The Board invites applicants to bring evidence of their experience and to demonstrate its relevance to the East-West Tie line project.

The Board finds that three additional criteria are appropriate to address the specific circumstances of this designation process. The Board will add the new criterion "Proposed Design for the East-West Tie Line". In creating this additional criterion, the Board has particularly considered the submissions of Board staff, the IESO, RES, the

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RECEIVED

MAR 3 1 2011

CHAIR
ONTARIO ENERGY BOARD

Ontario

MAR 2 9 2011

MC-2011-1537

Ms Cynthia Chaplin
Chair
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Chaplin:

Ontario's Long-Term Energy Plan, published November 23, 2010, identified five priority transmission projects based on the advice of the Ontario Power Authority (OPA). Among the five priority projects is the East-West Tie, identified by the OPA primarily to meet the need of maintaining long-term system reliability in Northwest Ontario.

Consistent with the intents identified in the Long-Term Energy Plan, I am writing to express the Government's interest that the Ontario Energy Board ("the Board") undertakes a designation process to select the most qualified and cost-effective transmission company to develop the East-West Tie.

The Board's Policy Framework for Transmission Project Development Plans is well suited to apply to the East-West Tie project. Such an approach would allow transmitters to move ahead on development work in a timely manner, encourage new entrants to transmission in Ontario and bring additional resources for project development. It will also support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

A designation process for the East-West Tie also promotes the Board's electricity objectives of protecting the interests of consumers with respect to prices and of promoting cost-effectiveness in the transmission of electricity. In respect of those particular ends, and given the location and value of the East-West Tie in ensuring reliability and maintaining efficiency and flexibility of the system, I would expect that the weighting of decision criteria in the Board's designation process takes into account the significance of aboriginal participation to the delivery of the transmission project, as well as a proponent's ability to carry out the procedural aspects of Crown consultation.

.../cont'd

As the Board has noted in its framework, the starting point for transmission project development planning should be an informed, effective plan from the province's transmission planner, the OPA. As such, it would be prudent for the Board to request further analysis for the East-West Tie from the OPA to support initiation of a designation process.

Sincerely,

Brad Duguid
Minister

1st SESSION, 41st LEGISLATURE, ONTARIO
65 ELIZABETH II, 2016

Bill 135

(Chapter 10
Statutes of Ontario, 2016)

An Act to amend several statutes and revoke several regulations in relation to energy conservation and long-term energy planning

The Hon. B. Chiarelli
Minister of Energy

1st Reading	October 28, 2015
2nd Reading	December 1, 2015
3rd Reading	June 2, 2016
Royal Assent	June 9, 2016

Printed by the Legislative Assembly
of Ontario

1re SESSION, 41e LÉGISLATURE, ONTARIO
65 ELIZABETH II, 2016

Projet de loi 135

(Chapitre 10
Lois de l'Ontario de 2016)

Loi modifiant plusieurs lois et abrogeant plusieurs règlements en ce qui concerne la conservation de l'énergie et la planification énergétique à long terme

L'honorable B. Chiarelli
Ministre de l'Énergie

1re lecture	28 octobre 2015
2e lecture	1er décembre 2015
3e lecture	2 juin 2016
Sanction royale	9 juin 2016

Imprimé par l'Assemblée législative
de l'Ontario

(b) reject the implementation plan and refer it back to the IESO or the Board, as the case may be, for further consideration and resubmission to the Minister.

Same

(6) Subsection (5) applies with necessary modifications to,

(a) amendments to implementation plans submitted under subsection (3) or (4); and

(b) implementation plans or amendments to implementation plans resubmitted to the Minister under clause (5) (b).

Procurement contracts

Definition

25.32 (1) In this section,

"implementation plan" means an implementation plan submitted by the IESO and approved under clause 25.31 (5) (a), including any amendments to the implementation plan that are submitted by the IESO and approved under that clause.

Entering into contracts

(2) The IESO shall, if required to do so under an implementation plan or a directive issued under subsection (5), and may, if an implementation plan provides the authority to do so, enter into contracts for the procurement of,

(a) electricity supply, capacity or storage;

(b) changes in electricity demand;

(c) measures related to the conservation of electricity or the management of electricity demand; or

(d) transmission systems or any part of such systems, including the development of all or part of such systems.

Transmitters

(3) Despite clause (2) (d), the IESO is not required to enter into a contract under subsection (2) in order to select a transmitter, unless the applicable implementation plan or directive provides otherwise.

Resolution of procurement contract disputes

(4) The parties to a procurement contract shall ensure that the contract provides a mechanism to resolve any disputes between them with respect to the contract.

Directives requiring IESO to undertake RFPs, etc.

(5) The Minister may, subject to the approval of the Lieutenant Governor in Council, issue directives requiring the IESO to undertake any request for proposal, any other form of procurement solicitation or any other initiative or activity that relates to a matter listed in subsection (2).

b) soit le rejette et le renvoie à la SIERE ou la Commission, selon le cas, pour étude plus approfondie et nouvelle présentation.

Idem

(6) Le paragraphe (5) s'applique, avec les adaptations nécessaires :

a) aux modifications des plans de mise en oeuvre présentées en vertu du paragraphe (3) ou (4);

b) aux plans de mise en oeuvre ou aux modifications de ceux-ci présentés de nouveau au ministre en application de l'alinéa (5) b).

Contrats d'acquisition

Définition

25.32 (1) La définition qui suit s'applique au présent article.

«plan de mise en oeuvre» Plan de mise en oeuvre présenté par la SIERE et approuvé en application de l'alinéa 25.31 (5) a), y compris les modifications du plan qui sont présentées par la SIERE et approuvées en application de cet alinéa.

Conclusion de contrats

(2) Si elle y est tenue par un plan de mise en oeuvre ou une directive donnée en vertu du paragraphe (5) et si elle y est autorisée par un plan de mise en oeuvre, la SIERE conclut des contrats d'acquisition visant l'obtention, selon le cas :

a) d'un approvisionnement en électricité ou d'une capacité de production ou de stockage d'électricité;

b) de changements de la demande d'électricité;

c) de mesures concernant la conservation de l'électricité ou la gestion de la demande d'électricité;

d) de réseaux de transport ou de toute partie de tels réseaux, y compris l'aménagement de tout ou partie de tels réseaux.

Transporteurs

(3) Malgré l'alinéa (2) d), la SIERE n'est pas tenue de conclure de contrat en application du paragraphe (2) en vue de choisir un transporteur, sauf disposition contraire du plan de mise en oeuvre ou de la directive applicable.

Règlement des différends

(4) Les parties à un contrat d'acquisition veillent à ce qu'il prévoie un mécanisme de règlement des différends en lien avec le contrat.

Directives obligatoires

(5) Sous réserve de l'approbation du lieutenant-gouverneur en conseil, le ministre peut, par directive, ordonner à la SIERE de lancer une demande de propositions, une autre invitation à soumissionner ou toute autre initiative ou activité portant sur un domaine indiqué au paragraphe (2).

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Assemblée législative de l'Ontario

Première session, 41e législature

Official Report of Debates (Hansard)

Journal des débats (Hansard)

Tuesday 3 November 2015

Mardi 3 novembre 2015

Speaker
Honourable Dave Levac

Clerk
Deborah Deller

Président
L'honorable Dave Levac

Greffière
Deborah Deller

LEGISLATIVE ASSEMBLY OF ONTARIO

ASSEMBLÉE LÉGISLATIVE DE L'ONTARIO

Tuesday 3 November 2015

Mardi 3 novembre 2015

The House met at 0900.

The Speaker (Hon. Dave Levac): Good morning. Please join me in prayer.

Prayers.

ORDERS OF THE DAY

ENERGY STATUTE LAW AMENDMENT ACT, 2015

LOI DE 2015 MODIFIANT DES LOIS SUR L'ÉNERGIE

Mr. Chiarelli moved second reading of the following bill:

Bill 135, An Act to amend several statutes and revoke several regulations in relation to energy conservation and long-term energy planning / Projet de loi 135, Loi modifiant plusieurs lois et abrogeant plusieurs règlements en ce qui concerne la conservation de l'énergie et la planification énergétique à long terme.

The Speaker (Hon. Dave Levac): Minister of Energy.

Hon. Bob Chiarelli: Mr. Speaker, I will be sharing my time with my parliamentary assistant, my colleague from Mississauga–Streetsville.

Today, I rise to move second reading of Bill 135, the Energy Statute Law Amendment Act, 2015. If passed, this act would establish in law a long-term energy planning process that is transparent, efficient and able to respond to changing policy and system needs. This is consistent with our government's commitment to enhance transparency and community participation through open data, open dialogue and open government initiatives.

It would support increased competition and enhanced ratepayer value by empowering the Independent Electricity System Operator, or IESO, to competitively procure transmission projects, and it would introduce two new initiatives to help Ontario families and businesses conserve energy and water to help manage costs at both the retail customer level and the system as a whole.

Before I pass on to my colleague from Mississauga–Streetsville, I wanted to highlight the three core components of this important piece of legislation. Firstly, our government recognizes that sound, prudent long-term energy planning is essential to a clean, reliable and affordable energy future. The best way to ensure that kind of robust system planning occurs is to consult with the public, First Nations, industry and the energy stakeholder community. The Ministry of Energy has developed our long-term energy plans to include broad consultations with the public and stakeholders. It's a transparent process for establishing the government's key goals and priorities for the province's energy system.

Today, our government is proposing legislation that would provide a statutory basis for this long-term energy planning process. The proposed legislation would ensure a consistent, long-term planning process is followed. As well, it would enshrine in legislation Ontario's Open Government Initiative by making consultation with the public, stakeholders and aboriginal groups throughout Ontario a requirement in the development of our future long-term energy plans—it will be put in the legislation.

To support an even more robust process, this legislation also ensures that supporting technical data are made public prior to the start of our next consultation phase. This would ensure everyone starts from the same appropriate technical level of understanding.

In addition, this legislation we are debating today also proposes an adjustment to transmission planning and procurement by providing the Independent Electricity System Operator with the ability to undertake competitive processes for transmitter selection or procurement when appropriate.

Competitive transmission procurement has only previously been done once before, through the Ontario Energy Board east-west tie designation. This is a very major transmission line that goes across northern Ontario, and very, very critical to the planning process that is in our long-term energy plan at the moment. Stakeholders and the Ontario Energy Board have agreed that the process run in 2012 was not as efficient as it should have been.

As we know, the IESO runs competitive procurement for energy generation projects with much success. We are proposing here to add transmission projects to their procurement processes. This measure is consistent, as well, with the recommendations of the Premier's Advisory Council on Government Assets.

Next, Mr. Speaker, as Ontario continues to implement its 2013 long-term energy plan, one of our key goals is energy conservation. Conservation helps families and businesses save money on their energy bills. It's as simple as that. It reduces the need to build expensive energy infrastructure, helping lessen the need for rate increases. And conservation reduces greenhouse gas emissions and air pollution, creating a cleaner future for our children and our grandchildren.

Ontario has already made great strides in building a culture of conservation. From 2005 to 2013, Ontarians conserved 8.7 terawatt hours of electricity, enough to power the cities of Mississauga and Oshawa in 2013. But there's more to do, Mr. Speaker, and this legislation takes additional steps.

Energy and water reporting and benchmarking initiatives for large buildings would require property owners to track their building's energy and water usage—as well as greenhouse gas emissions—over time, to determine how a building's energy performance is changing and how it compares to other, similar buildings. This ongoing review would help building owners identify opportunities to save energy and water, thereby saving money on their utility bills. It would also help tenants and buyers make informed property decisions, enabling property and financial markets to value energy- and water-efficient buildings, and it would help Ontario meet its conservation and greenhouse gas reduction goals.

Ontario is already demonstrating leadership to energy reporting and benchmarking requirements for government and broader public sector buildings. This is already being done, and it's being done quite successfully. As we proceed, it will only be required of large buildings—several dozen large buildings across the province. Extending this requirement to large buildings would align our policy with jurisdictions across the United States, Europe, the United Kingdom and Asia. We're not breaking new ground; we're following best practices, and some of those best practices are already taking place.

The second initiative sets water efficiency standards for products that consume both energy and water, such as dishwashers and washing machines. Currently, manufacturers can supply the Ontario market with models that meet our energy-efficient requirements, but they consume more energy than they would if we also included water efficiency standards. So if these same appliances and the same equipment had not only energy efficiency in it, but also added the water efficiency component to it, you would almost double the conservation benefits from the equipment.

Other jurisdictions, including the province of British Columbia and the US Department of Energy, have already harmonized both energy and water efficiency standards for these types of products. Again, we're not breaking new ground here, we're following best practices. By harmonizing with the US standards, Ontario can streamline the process for manufacturers, save consumers money and show continued leadership in setting efficiency standards.

In conclusion—I won't go into conclusion right now, because I'm going to speak to some of the issues that my parliamentary assistant was going to speak to, but he is not here yet.

Mr. John Yakabuski: Oh, you cannot refer to the gentleman in his absence.

Hon. Bob Chiarelli: Mr. Speaker, I'm going to try to demonstrate that the member from Renfrew–Nipissing–Pembroke has set a very, very good example of how to ad lib through time in this House, because he is masterful at it, and I wish I could emulate him.

Mr. Speaker, one of the main points of this particular submission is to create a process in legislation for planning the electricity system. There was a process that was contemplated under the Electricity Act. I forget what year it was enacted. It was a process that would have delegated to the Ontario Energy Board a very, very significant planning process. It was very prescriptive in terms of the type of consultation that had to take place, the length of time. Previous governments initiated the process to incorporate the Electricity Act process into the system, and it bogged down on a number of occasions.

0910

From 2010 to 2013, we did an alternative because we did not have that incorporated in legislation. We proceeded with what we called the long-term energy plan, or LTEP. LTEP, as it was implemented in 2013, included very, very massive consultation across the province that went from February through to November. It included, I think, nine sessions with First Nation and Métis communities. It went across the province. It had special sessions for stakeholders where they could have an interrelationship with the leaders from IESO, OPA, and it was extremely broad.

When the long-term energy plan 2013 was issued—it was December 2013—it was about 85 pages long, and it covered all the key components of the electricity system. The final product received a lot of plaudits and thank yous from the people, the stakeholders, who had participated in the process. When we announced that process, there were endorsements that came to the end product to the ministry, to the IESO and to the Ontario Power Authority for the fact that we listened and it was effective. Part of the long-term energy plan at that point established and required regional energy plans to be implemented, and so the 2013 long-term energy plan is being implemented now by those regional energy plans being implemented, and in each one of the regional plans there is additional detailed consultation. They consult with municipalities because, up until now, energy planning took place, and community planning and community official plans took place and they never connected the dots; they weren't on the same page. At the same time, the level of engagement, of energy conservation, combined heat and power projects, in municipalities was very, very scattered. It was successfully implemented particularly in Guelph, a leader in Ontario in that regard. But many municipalities were not paying attention to it.

So the regional structure for energy planning is being implemented now. One of the first to be implemented, one that actually was included, the regional plan was included in the long-term energy plan of 2013, was northwestern Ontario. That was the plan that identified the east-west transmission line to be implemented. It was the one that identified something that is absolutely transformational, and that is the transmission line to Pickle Lake, which will then move northerly to bring power, grid power, to 21 remote First Nation communities. It's transformational. That hasn't taken place anywhere in Canada or in other northern provinces.

About a month ago in Thunder Bay, they had the Chiefs of Ontario session, and at that time they announced a transformational public-private partnership. Watay Power is 100% First Nation. That group of First Nations—there were 20 First Nations who joined together in a public-private partnership with private sector companies Fortis and RES to actually put together a billion-dollar-plus transmission project to bring power up to Pickle Lake and then into remote communities in northern Ontario.

They had First Nations in that room who were in tears that they were leading it. Watay Power: The First Nations were leading this initiative. They had been working over the last two years with the OPA, the IESO and the Ministry of Energy. Most importantly, they were working meticulously to get all of these individual First Nations onside for this public-private partnership, which was transformational in terms of moving forward.

So the regional planning context is very, very important. That's what was included in the long-term energy plan. It's that type of consultation and forward-looking planning that is incorporated in this legislation to ensure that we can plan for the future.

There are issues that have arisen concerning what will happen to planning. This legislation deals with planning, and it makes it very, very clear that cabinet and the IESO will have the responsibility and the authority to designate transmission projects—not only to designate them, but to have them on a competitive basis moving forward. So we're very, very pleased to see that moving forward in this particular legislation.

Mr. John Yakabuski: We'll take it from here, Bob.

Hon. Bob Chiarelli: I'm hearing some chatter on the other side, and I didn't quite get the words. He is not speaking in his usual loud voice. I'm speaking about the member from Renfrew–Nipissing–Pembroke.

Mr. John Yakabuski: We'll take it from here.

Interjections.

Hon. Bob Chiarelli: I think I've almost used up his time. For those in Nepean–Carleton, they should be aware that Lisa MacLeod is here at the start of the parliamentary proceedings, doing her work and paying attention, and the member from Renfrew–Nipissing–Pembroke is doing his usual thing of trying to be interruptive.

The other issue that I wanted to address in terms of this legislation are the issues regarding the equipment and appliances having conservation both with respect to water and with respect to electricity. That's new in Ontario. It involved a lot of internal discussions and some external discussions with manufacturers and so forth. One of the issues there was whether it should be done by the Ministry of the Environment or the Ministry of Energy, and we were able to resolve that issue successfully.

In terms of other planning issues, one of the significant elements that came out of the long-term energy plan was the regional planning and the municipal planning that was relative to renewable energy. In that particular case, we did initiate consultations through the IESO and the OPA before they were merged, and that turned out to be quite successful. As you know, the outcome of that particular process is that municipalities now have a lot more input into the issues.

Ms. Lisa MacLeod: He's here.

Hon. Bob Chiarelli: I know one of the tardiest and most attentive members in this place is the member from Mississauga–Streetsville. He just attended, and I'm just contemplating—I was just given a copy of his speech and told, "Just read his speech." I thought maybe we would teach the member a lesson and I would read his speech, and then he would be able to listen to it to see whether he prepared a good speech or not. But, Mr. Speaker, I won't do that. I'll ask the member to address the issues now. Thank you.

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The Acting Speaker (Mr. Rick Nicholls): I thank the Minister of Energy for his promptness, for his on-the-spot dialogue.

I now turn the debate over to the member from Mississauga–Streetsville.

Mr. Bob Delaney: I certainly thank the finest minister that I've ever had the privilege of working with for doing some excellent ragging of the puck, I gather.

I'm tempted to begin this morning with a discussion of traffic in Toronto after spending two most interesting hours-plus sitting in it—

Hon. Mario Sergio: We need more money for infrastructure.

Mr. Bob Delaney: Yes, exactly. It sort of struck me as odd because the weather was perfect, the roads were dry, and it was just volume of traffic. But that's the subject for yet another discussion and a different act, and I can hardly wait. Of course, if I were to continue on this, my good friend and colleague across the away from Renfrew–Nipissing–Pembroke, who loves to spar with me in debate, would say, "But he's not addressing the act."

I would like today to rise in support of the second reading of the proposed Energy Statute Law Amendment Act, 2015. If passed, this act would establish in law a long-term energy planning process that is transparent, efficient and able to respond to changing policy and system needs. It would support increased competition and enhanced ratepayer value by empowering the Independent Electricity System Operator, which I'm going to refer to by its acronym, IESO, to competitively procure transmission projects, and it would introduce two new initiatives to help Ontario families, businesses and the province as a whole conserve energy and water to manage costs.

Speaker, the province recognizes that sound, prudent, long-term energy planning is essential to a clean, reliable and affordable energy future. The Ministry of Energy uses the development of long-term energy plans to conduct broad consultations with the public and with

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Thursday 5 May 2016

Jeudi 5 mai 2016

Speaker
Honourable Dave Levac

Président
L'honorable Dave Levac

Clerk
Deborah Deller

Greffière
Deborah Deller

LEGISLATIVE ASSEMBLY OF ONTARIO

ASSEMBLÉE LÉGISLATIVE DE L'ONTARIO

Thursday 5 May 2016

Jeudi 5 mai 2016

The House met at 0900.

The Speaker (Hon. Dave Levac): Good morning. Please join me in prayer.

Prayers.

ORDERS OF THE DAY

ENERGY STATUTE LAW AMENDMENT ACT, 2016

LOI DE 2016 MODIFIANT DES LOIS SUR L'ÉNERGIE

Mr. Chiarelli moved third reading of the following bill:

Bill 135, An Act to amend several statutes and revoke several regulations in relation to energy conservation and long-term energy planning / Projet de loi 135, Loi modifiant plusieurs lois et abrogeant plusieurs règlements en ce qui concerne la conservation de l'énergie et la planification énergétique à long terme.

The Deputy Speaker (Ms. Soo Wong): I recognize the minister.

Hon. Bob Chiarelli: I'm pleased to share my time today with my colleague, the hard-working member from Burlington, Eleanor McMahon.

Speaker, today I rise to move third reading of Bill 135, the Energy Statute Law Amendment Act, 2015. This proposed legislation would accomplish several very important measures for a stronger, more collaborative energy planning process. It would improve energy transmission reliability in the province of Ontario, and the new planning regimen creates a strong platform to keep electricity rates competitive and for a strong economy.

Before I get into more detail of the proposed legislation, Speaker, I want to recognize the hard work, dedication and commitment of the Ministry of Energy staff and the staff across our energy agencies, including the Independent Electricity System Operator, the Ontario Energy Board and Ontario Power Generation, all of whom have worked tirelessly on this vital piece of legislation and the effort they devote to the energy sector throughout the province every day.

I'd also like to acknowledge energy's role in building Ontario up. Nothing is more essential to our everyday quality of life and economic success than a steady supply of clean, reliable and affordable electricity. Our economy continues to grow, and as technical and operational innovations accelerate, ratepayers, economies, industry and governments need to adapt, and adapt quickly.

I'm talking about electric cars, electrified transit, behind-the-meter generation, smart grid technology, electricity storage, innovations in renewable energy, off-grid generation, modernizing building codes and, most of all, eliminating carbon emissions. This makes our unwavering commitment to innovative, cost-effective, clean and reliable power an ongoing necessity for our economy, our environment and our quality of life.

Mr. Speaker, Bill 135 creates a reliable planning mechanism to keep electricity rates competitive and our economy strong and growing. One of the biggest myths we hear—I know it's one often promulgated by members of the opposition—is that electricity prices in Ontario are the highest in North America. This is just plain wrong. Ontario's residential electricity rates are, and will remain, competitive with jurisdictions in North America. When comparing the cost per kilowatt hour, Ontario's rates are lower than most American cities and significantly lower than electricity rates in European cities. While some Canadian provinces have lower prices than Ontario, Ontario has competitive prices with other provinces such as Nova Scotia, Newfoundland, Saskatchewan and PEI.

While most other jurisdictions are still burning dirty coal for two thirds of their power, our government is proud that we have achieved competitive rates while undertaking the largest climate change initiative in North America. This requires smart planning legislation and smart planning policies.

Our 2013 long-term energy plan is putting Ontario in a competitive place. The 2013 long-term energy plan is the platform on which we're building the needs of the future through Bill 135.

Looking across Canada, Ontario's recent 2.5% bill increase is reasonable and stacks up competitively across our comparators. BC Hydro rates increased by 4% on April 1, 2016; Saskatchewan power rates were approved for a 5% increase in 2015; Manitoba Hydro applied a rate increase of 3.95% as of April 1, 2016; and Newfoundland Power applied for a rate increase of 3.6% for residential customers as of July 1. Yes, our rates went up by 2.5%; I challenge any member in the Legislature to find a jurisdiction in North America where rates are not going up. The issue is, how do you keep the increases to a minimum? That is a very, very significant issue when it comes to electricity planning.

We also recognize that the price of electricity can be difficult for those who pay a higher share of their income toward the bill, particularly low-income families and seniors on a fixed income. That's why the Ontario Energy Board launched the Ontario Electricity Support Program for lower-income families, and that is why the debt retirement charge was removed on January 1 of this year, saving the average family a combined $430 annually.

We also know that bills can be even harder for families and seniors in rural and remote areas that heat with electricity or use medically assistive devices. That's why we doubled the monthly benefit these families can access to up to $100.

Bill 135, when passed, represents a planning framework that makes these price mitigation measures possible by government.

Through our planning framework, we have additional programs that help reduce bills for Ontario families. The Ontario Energy and Property Tax Credit saves qualifying individuals up to $993 per year; the Low-Income Energy Assistance Program provides emergency financial support; the saveONenergy Home Assistance Program provides free home energy efficiency assessments and energy-saving measures; and the Northern Ontario Energy Credit helps families and individuals in northern Ontario, providing individuals up to $143 in savings.

Regarding industrial prices, northern Ontario actually has one of the lowest industrial electricity rates in North America—among the lowest in Canada and lower than 49 American states; the third-lowest in North America. Industrial rates in southern Ontario are lower than in Michigan, Wisconsin, New Jersey and California, and below the American average.

Just a few weeks ago, the Ontario Chamber of Commerce partnered with the Ministry of Energy to publish clear data on these facts. It's called the Ontario Energy Report and it's available on the ministry website at www.ontarioenergyreport.ca. I'm going to read that again: www.ontarioenergyreport.ca. Speaker, it's there. There's a chart showing the comparable prices. It's credible, it's objective and it shows that Ontario is doing extremely well compared to our competitors.

Bill 135, if passed, would allow a planning framework to continue and expand existing programs. Just last week, I was in Timmins discussing some of the programs the Ministry of Energy now offers to even further reduce the impact of electricity prices on the bottom line of some of Ontario's industrial consumers. That's the industrial electricity incentive. This is a program our government launched in 2012 to offer sharply discounted rates of up to 50% for job creators across the province, with a special focus on industrial consumers like the mining industry, greenhouse growers, refrigerated warehouses and data-processing centres. Speaker, I want to provide some examples of companies that are benefiting from this IEI program, which provides up to a 50% discount off their electricity bills, a program that could be expanded under the Bill 135 planning process.

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I was fortunate to be in Timmins to highlight two local companies, Alamos Gold and St. Andrew Goldfields, which both have made use of this program and expanded their mining operations in that region. We were up there with our staff two or three weeks ago. We had a very positive reception, particularly from the company involved. Alamos, for example, has increased its daily gold output by 2,000 tonnes per day, creating 75 new jobs and supporting more than 700 good jobs for this community. The CEO of that company credits this program with enabling them to proceed in this way.

These two success stories in the riding of the member from Timmins–James Bay aren't the only companies participating in this program.

Mr. John Yakabuski: What about in Pembroke?

Hon. Bob Chiarelli: My critic the member from Pembroke-Renfrew talks about the company in his riding that benefited very significantly and was able to rehire over 100 jobs. I appreciate the fact that my critic gives us credit, once in a while, for doing something good. Thank you.

In fact, the list of IEI program beneficiaries includes FNX Mining Company Inc., in the member from Sudbury's community; Vision Extrusions, in the member from Vaughan's community; Roelands Plant Farms Inc., in the member from Lambton–Kent–Middlesex's community; Amco Farms Inc., in the member from Chatham-Kent–Essex's community; Omya Canada Inc. and Tweed Inc., in the member from Lanark–Frontenac–Lennox and Addington's community; New Gold Inc. and EACOM Timber Corp., in the member from Kenora–Rainy River's community; White River Forest Products, in the member from Algoma–Manitoulin's community; and Resolute FP Canada Inc., in the Thunder Bay community. Just for the record, Speaker, seven of these 10 examples are benefiting companies and communities that are located in opposition members' ridings.

Mr. Speaker, we're going to continue to focus on ensuring that our electricity system is clean, reliable and affordable for all. That can only be accomplished with a modern, updated planning framework, which Bill 135 would provide. And we're continuing to make significant progress in transforming the electricity system into one that Ontarians can continue to count on for reliability, leadership and clean energy.

Speaker, when our government came to office, 25% of Ontario's generation was from very cheap but very dirty coal. A central priority of the government when it comes to energy planning was to ensure a very clean supply mix so that we'd have a healthy population, and a strong planning platform is needed to initiate these types of transformational policies. In that context, Speaker, we have closed all of our coal-fired electricity plants, helping to clean up the air that was making our kids sick and saving the province $4.4 billion per year in environmental and health care costs. That is the largest emissions reduction action plan in North America, taking the equivalent of seven million cars' worth of emissions off the roads in Ontario, efforts that reduce carbon emissions and fight climate change. It wasn't an easy decision, Speaker, but it was one our government committed to achieve, and, as they say, promise made, promise kept.

But, Speaker, we can't lay down our tools. And one of the best tools we have, moving forward, will be Bill 135.

We've taken energy planning and electricity reliability to a level ignored under previous governments, and we have rebuilt our transmission and distribution systems, investing $34 billion in the generation and transmission that ensure that when Ontario needs electricity, you can count on it to be there. It's easy to forget that this wasn't always the case, not long ago, and the system was crying out for proper planning frameworks.

I think we can all recall the rolling brownouts and blackouts that made Ontario an unreliable place to do business and set up shop, and that the then-PC government had installed large portable generators in downtown Toronto as a backup for an unreliable and dirty system that had a deficit of electricity. So after years and years of underinvestment, we finally turned the page and ensured that when you flip the switch, the lights will come on.

Speaker, Ontario has also recently confirmed that the future of energy planning in Ontario is strongly rooted in an affordable, reliable, emissions-free supply of baseload nuclear power. This was planned for under the 2013 long-term energy plan, the predecessor to Bill 135. Under that plan, we will continue building for the future, undertaking a very significant nuclear refurbishment plan at the Darlington and Bruce reactors.

What's truly amazing about this commitment is that all nuclear facilities in Ontario are variants of the Candu reactor design, and it's significant that more than 90% of the supply chain that supports this type of nuclear units is located right here in Ontario. That supply chain represents more than 180 companies employing tens of thousands of Ontarians in well-paying jobs.

Refurbishment is also a direct vote of confidence in this supply chain and this domestic industry. It's a vote of confidence in companies like Cambridge's BWXT Canada Ltd., which employs more than 500 people in the community, or Peterborough's General Electric Hitachi nuclear energy facility, which employs more than 350 people in highly skilled trades in the nuclear industry, or perhaps a vote of confidence in Cameco's Port Hope facility, which employs 660 people in the nuclear industry. That energy planning vote of confidence is going to create 60,000 Ontario jobs. It's going to invest $25 billion in updated and needed energy infrastructure. It's going to drive economic growth in communities across Ontario, and it's going to secure 30 years of emissions-free power. That's amazing as well.

If all that wasn't enough, it's going to help stabilize prices in Ontario. It's going to secure three decades of emissions-free power at a very affordable price of just 7.7 cents per kilowatt hour on average going into the grid.

The planning framework that enabled this success needs a refresh, and that's going to take place in Bill 135. An affordable, clean supply mix is central to our planning. That has recently been reflected in the IESO's first competitive procurement for renewable energy contracts. Last month, the IESO announced that this successful first round would come in at an average price of 8.5 cents per kilowatt hour, which is comparable to conventional generation, and will include 13 projects, or 80% of the total projects, with significant aboriginal or First Nation participation. And 75% of these 16 projects had local community support, Speaker.

So yes, the world of energy and electricity is changing at an accelerated pace. That's what Bill 135 is all about. What's incredibly significant about our renewable achievements of local support and lower prices is that, compared to the forecasts in our 2013 long-term energy plan, our system now benefits from $3.3 billion in savings, saving the average consumer $1.67 per month on their electricity bill, thanks to renewables. This is a significant change in how we procure renewable power in Ontario and sets a strong benchmark for the future of energy planning in this province, one that includes nuclear, renewables, water power and natural gas.

All of these decisions and actions taken by our government to drive cost pressures down, to ensure reliable supply and transmission and to transform our system from one dependent on coal to one free of it relate directly to the legislation we are considering here today.

If passed, this act would establish in law a long-term energy planning process that is transparent, efficient and able to respond to changing policy and system needs, and also, very critically, enable to change a plan and adjust quickly to the accelerated innovation that we're seeing across the energy and electricity sector. This is consistent with our government's commitment to enhance transparency and community participation through open data, open dialogue and open government initiatives.

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This act would also support increased competition and enhanced ratepayer value by empowering the Independent Electricity System Operator to competitively procure transmission projects. This is important because previously, there was a regimen that allowed, for example, Hydro One to initiate transmission projects and to implement them. We now have implemented a competitive process where the IESO will open up transmission implementation to all players in these sectors.

This act would also introduce two new initiatives to help Ontario families and businesses conserve energy and water to help manage costs at both the retail customer level and the system as a whole.

First, it would require owners of large buildings to track their buildings' energy and water use and greenhouse gas emissions over time, to allow owners and renters to determine how a building's energy performance is changing and how it compares to similar buildings.

Second, it would set water efficiency standards for products such as appliances that consume both energy and water, like dishwashers and washing machines, allowing Ontarians to make the best choices for themselves when shopping for appliances.

We are not reinventing the wheel here with these two initiatives. Both of these initiatives follow best practices in a significant number of jurisdictions in Canada, the US and the United Kingdom.

Ontario Energy Board (Board Staff) INTERROGATORY #3

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Page 7

Hydro One states that incremental transaction costs will be financed through productivity gains associated with the transaction and will not be included in either GLPT or Hydro One's revenue requirement and thus will not be funded by ratepayers.

a) Please provide the magnitude of the incremental transaction costs that will be incurred as a result of this transaction.

Response

Incremental transaction costs are described in Exhibit A, Tab 2, Schedule 1, Page 7. HOI expects to incur these types of costs in two phases.

Phase 1 (2016)

In phase 1, costs associated with negotiating the transaction and obtaining all required regulatory approvals as well as initial steps to integrate GLPT and Hydro One financial systems will be incurred. The major integration activity during this period is loading and validating GLPT's financial data into Hydro One's financial systems. This will provide functionality for monthly trial balance uploads, intercompany transactions and reporting. This phase is estimated to cost approximately $3,500,000.

Phase 2 (2018, and early 2019)

In this phase, in preparing for a seamless transition and full operational integration, Hydro One will be completing a number of discovery / collection activities, including:

- Collect data / drawings and prepare for data loading
- Assess data systems structural setup for integration and testing
- Implement nomenclature solutions (data systems, diagrams, prints, Operating / NMS)
- Prepare operations to be integrated into OGCC Control / NMS / SCADA environment
- Prepare for migration of all IT / Database management information into existing Hydro One tools

Full operational integration entails all finance tools, new equipment assets, database updates, customer conversions, settlements, supply chain, human resources, telecommunications, work management, and full SCADA integration. This process will commence in the latter half of 2018 (and into early 2019). The estimated cost of these activities is $3.9M.

Energy Probe INTERROGATORY #4

Interrogatory

References: Exhibit A, Tab 2, Schedule 1, Page 3 and Exhibit A, Tab 3, Schedule 1, Page 1

a) Please confirm Hydro One Tx and GLPT rates recently have been set for a two year period based on a Revenue Requirement based on Cost of Service.

b) Please provide for each entity, the annual Revenue Requirement and the realized rate of return for the period 2010-2015.

c) Leaving aside relative size argument(s), please explain why a 10 year rebasing for GPLT is appropriate for Hydro One and for existing ratepayers?

d) Given the historic revenue requirements for Hydro One TX and GLPT, please explain why inflation is an appropriate escalator for GPLT revenue requirement post 2019?

Response

a) Confirmed. Hydro One's current transmission revenue requirement for 2015 and 2016 was set under cost of service application (EB-2014-0140). On May 31, 2016, Hydro One submitted a 2 year cost of service revenue requirement application for 2017 and 2018, EB-2016-0160.

GLPT's revenue requirement for 2015 and 2016 was also set under a cost of service application (EB-2014-0238). GLPT expects to file a cost of service revenue requirement application later in 2016 for 2017 and 2018.

b)

	2010	2011	2012	2013	2014	2015
Hydro One Revenue Requirement ($M)	1,217.7	1,299.5	1,385.1	1,390.8	1,446.4	1,477.3
Hydro One Realized Return on Equity (%)	10.49	10.95	12.41	13.22	13.12	10.93
GLPT Revenue Requirement ($M)	34.2	34.8	36.1	38.1	38.7	39.6
GLPT Realized Return on Equity (%)	11.03	10.94	11.86	11.51	11.42	9.66

c) HOI relied on the Handbook, in selecting a 10 year deferral period. Specifically, page 12 of the Handbook permits deferral of rebasing for up to 10 years and states that the extent of the deferred rebasing period is at the option of the applicant and no supporting evidence is required to justify the selection of the deferred rebasing period. In allowing this, the OEB requires the applicant to identify the specific number of years for which deferral is sought. HOI has provided this information.

d) GLPT's historical revenue requirement has increased on average at a rate of 3% per year over the 2010-2015 period. See part b) above. The GDP inflation rate over the same time period averages approximately 1.6%[1]. As a result, increasing GLPT revenue requirement by the rate of inflation is an appropriate escalator.

[1] From OEB distributors inflation factors (2011-1.3%; 2012-2.0%' 2013-1.6%; 2014-1.7%; 2015-1.6%)

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2014-0213

HYDRO ONE INC., HYDRO ONE NETWORKS INC., WOODSTOCK HYDRO SERVICES INC.

Applications for the Acquisition of Woodstock Hydro Services Inc. by Hydro One Inc.

BEFORE: Ellen Fry
Member

Cathy Spoel
Member

September 11, 2015

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) regarding an application seeking various approvals filed by Hydro One Inc., Hydro One Networks Inc. (Hydro One) and Woodstock Hydro Services Inc. (Woodstock).

Hydro One Inc. requests OEB approval to purchase all of the shares of Woodstock Hydro Holdings Inc., which owns Woodstock. As part of this purchase, the OEB is also asked to approve: (a) a one percent reduction in Woodstock's 2014 electricity distribution rates, to be frozen for five years until 2020; (b) the transfer of Woodstock's distribution system to Hydro One; (c) the transfer of Woodstock's electricity distribution licence and rate order to Hydro One; and (d) deferral of rate rebasing for Woodstock for up to ten years from the date of closing the share purchase transaction.

The following sections of the Ontario Energy Board Act, 1998 (the Act) provide the OEB with authority to decide these applications:

- Section 86, which requires OEB approval for a merger, acquisition of shares, divestiture or amalgamation that results in a change of ownership or control of an electricity transmitter or distributor
- Section 78, which allows the OEB to set rates, including the rate reduction that Woodstock is proposing for electricity distribution service until 2020
- Section 18, by which the OEB may transfer an authority or a licence given by the OEB

The OEB's Combined Decision[1] established the scope of issues that the OEB considers in deciding section 86 applications and ruled that the relevant test is "no harm". Under the no harm test, the OEB considers whether the proposed transaction would have an adverse effect relative to the status quo in relation to the OEB's statutory objectives set out in section 1 of the Act. If the proposed transaction would have a positive or neutral effect on the attainment of the statutory objectives, then the OEB should grant the application.

In reaching its decision in this case, the OEB was assisted by the participation of intervenors and OEB staff.

[1] RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

The OEB has determined that the proposed share purchase transaction and the proposed transfer of Woodstock's distribution system to Hydro One meet the no harm test.

The OEB approves these transactions as well as the proposed rate reduction and the transfer of Woodstock's electricity distribution licence and rate order to Hydro One.

The OEB is not prepared to grant the request for the deferral of rate rebasing for Woodstock for up to ten years from the date of closing the share purchase transaction. The OEB finds that there is insufficient evidence to support a ten year deferral and instead approves a deferral of rate rebasing for Woodstock for a period of five years from the date of closing of the share purchase transaction.

The OEB has placed certain conditions on its approval of these applications, which are set out in detail in this Decision.

2 THE APPLICATION

Hydro One Inc., Hydro One and Woodstock filed related applications with the OEB on July 11, 2014 for the following:

1. Hydro One Inc. applied for leave to purchase all of the issued and outstanding shares[2] of Woodstock Hydro Holdings Inc. under section 86(2)(b) of the Act.
2. Woodstock applied for inclusion of a rate rider in its 2014 OEB approved rate schedule to give effect to a 1% reduction relative to 2014 base electricity delivery rates (exclusive of rate riders) under section 78 of the Act.
3. Woodstock applied for leave to dispose of its distribution system to Hydro One under section 86(1)(a) of the Act.
4. Woodstock applied for leave to transfer its distribution licence and rate order to Hydro One under section 18 of the Act.

The applications were amended on May 22, 2015 to add an additional request based on a new policy of the OEB released on March 26, 2015.

Hydro One requested approval to defer the rate rebasing of Woodstock for up to ten years from the date of closing of the proposed transaction.

As part of its proposal for deferral of rate rebasing, Hydro One has proposed an earnings sharing mechanism for years 6 to 10 after the date of closing.

The OEB issued its Notice of Applications and Hearing on July 31, 2014, inviting intervention and comment. The OEB approved intervention requests by the School Energy Coalition (SEC), the Corporation of the Township of Zorra and the Concerned Citizens against the Sale of Woodstock Hydro (Concerned Citizens).

The OEB provided for interrogatories and submissions on the application and held two days of oral hearing. At the end of the first day of hearing on January 15, 2015, the OEB adjourned the hearing to consider the relevance of documents provided on a confidential basis by Woodstock to the OEB hearing panel during the hearing. The OEB issued a decision on this issue on May 8, 2015. Hydro One and Woodstock filed a letter amending the application on May 12, 2015 and, at the request of the OEB, filed additional evidence on May 22, 2015. The OEB reconvened the oral hearing on May 27, 2015.

[2] Hydro One Inc.states that for purposes of tax planning it will use a numbered company to own the purchased shares on an interim basis, but that Hydro One Inc. will then become the owner of the shares.

3 REGULATORY PRINCIPLES

3.1 The No Harm Test

The OEB's decision in RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257 (the Combined Decision) established the scope of issues that the OEB considers in deciding section 86 applications and ruled that the relevant test is "no harm". The Combined Decision has been considered in detail in recent OEB decisions[3].

The no harm test involves consideration of whether the proposed transaction would have an adverse effect in relation to the OEB's statutory objectives. If the proposed transaction would have a positive or neutral effect on the attainment of the statutory objectives, then the application should be granted. The statutory objectives to be considered are those set out in section 1 of the Ontario Energy Board Act:

a) To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service
b) To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry
c) To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances
d) To facilitate the implementation of a smart grid in Ontario
e) To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities

At the time the Combined Decision was issued, the Act contained only the first two of its current section 1 objectives.

The issues raised by the parties in this proceeding relate to the first three objectives. However, the OEB must be guided by all five objectives in section 1, if they are relevant

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[3] Hydro One Inc./Norfolk Power Distribution Inc. EB-2013-0196/EB-2013-0187/EB-2013-0198
Cambridge and North Dumfries/Brant County Power Inc. EB-2014-0217/EB-2014-0223
Hydro One Inc./Haldimand County Hydro Inc. EB-2014-0244

to the application before it. In this case, the OEB finds that there is no reasonable indication that harm could potentially be caused by the proposed transaction in relation to the last two objectives in section 1 and is therefore focusing its consideration of the no harm test in relation to the first three objectives.

While each of these objectives is considered separately, the OEB does not agree with the submission made by SEC that each objective must be individually satisfied in order to pass the no harm test. The OEB considers whether the no harm test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of the objectives.

3.2 OEB Policy on Rate-making Associated with Consolidation

The OEB set out its policies on rate-making associated with consolidation in its report entitled "Rate-making Associated with Distributor Consolidation" issued July 23, 2007 (the 2007 Report) and a further report which was issued on March 26, 2015 (the 2015 Report).

2007 Report

The 2007 Report permitted distributors that apply to the OEB for approval of a consolidation transaction to defer the rate rebasing of the consolidated entity for up to five years from the date of closing of the transaction to allow a time period in which efficiency gains due to the consolidation could offset transaction costs.

The 2007 Report stated that the issue of rate harmonization of the utilities comprising the consolidated entity is better examined at the time of rebasing of rates of the consolidated entity. While the application to approve the transaction would not address the setting of new rates for the consolidated entity, parties are required to indicate in their application whether they intend to undertake a rate harmonization process after the proposed transaction is completed and if they do, to provide a description of the plan.

The 2007 Report also stated that it is not appropriate for a distributor to be permitted to recover an acquisition premium or net consolidation losses in whole or in part through rates while retaining the realized benefits of the transaction over the deferral period.

2015 Report

In response to concerns that the existing OEB policy on rate setting for consolidation may be adversely impacting further consolidation in the electricity distribution sector, the OEB issued a revised policy in March of 2015. In the 2015 Report, the OEB extended the potential rate rebasing deferral period, stating that consolidating distributors may apply to defer rebasing for a period of up to 10 years after the closing of the transaction. The OEB set out its expectations for the deferral period as follows:

a) For the extended period (i.e. the period between year 5 and year 10), the OEB requires the consolidating entity to implement an earnings sharing mechanism (ESM) of 50:50 sharing with customers where the return on equity (ROE) for the consolidated distributor is greater than 300 basis points above the allowed ROE for the consolidated distributor.

b) A distributor who is on a Price Cap IR or Annual IR may apply for an Incremental Capital Module (ICM) that includes normal and expected capital investments during a deferred rebasing period.

c) The following incentive rate plans will apply during any deferred rebasing period after a distributor's original incentive regulation (IR) plan is complete:

    I. A distributor on Price Cap IR will continue to have its rates based on the Price Cap adjustment mechanism during the remainder of the deferral period.

    II. A distributor on the Annual IR will continue to have rates based on the Annual IR index, until it selects a different option.

    III. A distributor on Custom IR will move to having rates based on the Price Cap IR adjustment mechanism, during the remainder of the deferral period.

4 APPLICATION OF THE PRINCIPLES TO THE APPLICATION

4.1 The No Harm Test

Price, Cost Effectiveness and Economic Efficiency

Hydro One submitted that the proposed transaction protects Woodstock customers through: (a) a commitment to freeze base electricity distribution delivery rates for a period of five years from closing of this transaction, and (b) a 1% reduction on base distribution delivery rates for that period. In Hydro One's view, these measures provide Woodstock customers with protection against rate increases that could have occurred over that same time period if the transaction had not proceeded.

In its application and response to Board Staff Interrogatory No. 1, Hydro One has provided a description of where it expects to achieve cost savings and operational efficiencies through the proposed transaction and an outline of expected capital expenditure savings.

Hydro One's evidence is that operational efficiencies from the elimination of duplication and economies of scale in various aspects of utility operations result in operating and capital savings, both immediate and over time, which will provide long-term benefits to ratepayers relative to the status quo.

Hydro One identified geographic contiguity benefits resulting from being situated immediately adjacent to Woodstock’s service area. These include rationalization of local space needs through the elimination or re-purposing of duplicate facilities such as service centres, more efficient scheduling of operational and maintenance work and dispatch of crews, and more efficient utilization of work equipment. Hydro One submitted that this leads to lower capital replacement needs over time, and more rational and efficient planning and development of the distribution system.

Hydro One submitted that efficiency gains are also expected from the elimination of redundant administrative and processing functions. These include reductions in back-office and senior management staff, corporate governance costs, the number of regulatory filings, information technology costs, and the use of external consultants and contractors. Hydro One also argued that savings due to economies of scale can be expected due to the larger customer base resulting from consolidation. This would apply to functions such as billing, customer care, human resources and financial systems.

Hydro One provided a year over year comparative cost structure analysis for the proposed transaction, reflecting overall expected operations, maintenance and administrative (OM&A) savings based on comparing Woodstock, remaining as a stand-alone distribution utility, to having the Woodstock operations integrated into Hydro One’s existing operations. Hydro One presented three scenarios with respect to efficiency savings: a medium cost scenario representing the base case and high and low cost scenarios illustrating a plus/minus 20% variation on Hydro One's forecast. Using the medium cost scenario, Hydro One projected net annual cost savings from the transaction of approximately $3.0 million in OM&A costs and approximately $1.0 million in capital expenditure costs. Hydro One submitted that ongoing OM&A savings will result in downward pressure on the Woodstock ratepayer’s cost structure.

Hydro One confirmed in its testimony[4] that the forecasted OM&A costs do not include overhead costs whereas the Woodstock status quo scenario does. Hydro One’s evidence is that costs for Woodstock as a stand-alone utility take into account depreciation and interest costs whereas costs of this nature will form part of the broader Hydro One asset portfolio as Woodstock operations become integrated with Hydro One’s existing operations. Hydro One did state, however, that the costs used to underpin future rate designs will include the full allocation of common costs, including corporate overheads.

OEB staff submitted that the evidence provided by Hydro One supported the claim that the proposed transaction can reasonably be expected to result in cost savings and operational efficiencies, but that the forecasted savings can be expected to be lower than projected as the forecast of the Hydro One costs does not include all the OM&A costs that will be allocated to Woodstock.

OEB staff submitted that if the OEB approves the transaction, the OEB should require Hydro One to file a report with the first rate application for the Woodstock existing customers that includes all costs associated with serving the Woodstock service area, delineating the savings achieved as a result of the proposed transaction and how those savings will be allocated. Hydro One submitted that it plans to report to the OEB on the achieved savings resulting from the acquisition both on an annual and on a cumulative basis, in the same format as Table 2 in Hydro One's documentary evidence[5]. Hydro One submitted that all actual incremental OM&A and capital expenditure costs arising as a result of the transaction would be included in this report.

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[4] OEB Oral Hearing Transcript, Volume 2, May 27, 2015, pgs 53-56
[5] Table 2 projects the incremental costs required to serve Woodstock's service territory, so as not to double count cost expenditures already required to serve Hydro One's legacy customers.

Hydro One submitted that it is reasonable to believe that its costs to serve Woodstock's customers would be less than Woodstock's costs of serving its customers based on a comparison of its OM&A forecast to serve customers in its high density residential rate class (UR) ($181 per customer per year) to Woodstock's forecast OM&A cost ($277 per customer per year).

SEC submitted that it was not clear from the evidence whether Hydro One intends to ensure lower costs for Woodstock customers after the rate freeze, or whether the cost savings from the acquisition will be spread across Hydro One's entire system, resulting in lower rates for existing Hydro One customers but higher rates for Woodstock customers. SEC urged the OEB to clarify its expectations with respect to future rates in consolidation situations, particularly whether the cost and rate component of the no harm test applies specifically to the directly impacted customers or all customers of the consolidated utility.

Concerned Citizens argued that the savings for Woodstock customers are minimal and that the lower cost structure will be to the benefit of Hydro One's existing customers rather than the current customers of Woodstock.

Hydro One submitted that future rates will reflect the cost to serve the Woodstock customers as impacted by the productivity gains resulting from consolidation.

OEB Findings

The OEB is satisfied that the evidence provided by Hydro One meets the no harm test as it relates to the price of electricity service. The OEB has set out in past decisions that it bases its decision on the cost drivers associated with the proposed transaction. While the OEB takes note of the one percent reduction in rates for a five year period, it is not determinative. The OEB considers the cost drivers from the proposed transaction in order to assess whether there will be harm.

The OEB accepts Hydro One's evidence concerning the cost drivers that are likely to result in savings being achieved. While, as submitted by OEB staff, the projected savings may be lower than shown in Hydro One's forecasts, and while it is not clear which of Hydro One's cost projection scenarios will turn out to be most accurate, the OEB finds that the no harm test is met.

Future rates for the current customers of Woodstock will be determined in a future rates proceeding. Hydro One's evidence is that rates will be determined based on the costs to service Woodstock customers. The OEB wants to ensure that Hydro One is able to provide the Board with full information on the costs and savings associated with providing service to Woodstock customers. Therefore, the OEB will require Hydro One to report on the following at such time as Hydro One applies for future rates for the existing customers of Woodstock:

a) All costs (including overhead corporate costs) associated with serving the Woodstock service area, recorded and reported both on an annual and cumulative basis from the time of the closing of the share purchase transaction
b) Actual savings achieved (being the difference between the total costs in a) and the costs of Woodstock as a stand-alone utility)
c) An indication of how those savings have or will be allocated

Hydro One has argued that requiring this type of reporting reduces efficiencies. However, the OEB's ability to discharge its duty to protect the public interest by understanding the costs of serving Woodstock customers overrides this concern. The OEB finds that this reporting is necessary to properly inform the OEB's future decisions on rates for the Woodstock service area.

Reliability and Quality of Electricity Service

Hydro One's evidence indicates that it is committed to the retention of Woodstock's existing operations personnel and will retain local knowledge and skills to allow it to maintain or improve reliability and service quality. Hydro One plans to construct a new operating centre to consolidate operations between Hydro One's Beachville Operating Centre and Woodstock's Operating Centre on Graham Street in Woodstock. Hydro One submits that this will provide a larger operating presence with reduced distance to travel; and bring additional resources within the City of Woodstock to support Hydro One's ability to deliver reliable service.

Based on the OEB's 2013 Electricity Distributor Scorecard (Scorecard), SEC and Concerned Citizens questioned Hydro One's reliability performance, which the Scorecard indicates is significantly lower than that of Woodstock. Hydro One's evidence was that these statistics reflect reliability across Hydro One's entire service area, which is not representative of the reliability level that can be expected in the Woodstock service area.

Hydro One provided a comparison of reliability statistics from 2011-2013 for Hydro One customers in the vicinity of Woodstock to Woodstock's reliability statistics. Hydro One argued that this comparison indicated that these Hydro One customers experienced a level of service in terms of duration and frequency of interruptions comparable to Woodstock customers. SEC and Concerned Citizens disagreed and argued that Hydro One has constructed an arbitrary measure based on data from only one feeder, which is insufficient. SEC argued that Hydro One could have provided more compelling evidence by providing its reliability statistics for other communities similar to Woodstock that are served by Hydro One.

SEC and Concerned Citizens expressed concern about the maintenance of reliability and service quality once operations are integrated as no specific data will be available for Woodstock. They also expressed concern with respect to Hydro One's billing practices and customer service operations that were being investigated by the Ontario Ombudsman and how this would affect Woodstock customers.

SEC presented a comparison of the Scorecard customer service statistics of Hydro One and Woodstock, stating that Woodstock came out ahead on every reported statistic. SEC argued that this meant customer service levels will fall for Woodstock customers following the acquisition by Hydro One. Hydro One responded that 2013 represents an anomaly for Hydro One owing to problems it experienced with the implementation of a new billing and customer information system.

OEB staff submitted that, based on the evidence provided, Hydro One can reasonably be expected to maintain the service quality and reliability standards currently provided by Woodstock.

OEB Findings

The OEB finds that there is no reason to believe that reliability will decline as a result of the merging of the operations.

The OEB notes that comparative data and analysis has been provided by Hydro One showing similar reliability however that data has been challenged by intervenors as not being representative. A key difference between the two customer groups is that Woodstock serves a mix of 15,000 residential and industrial customers whereas Hydro One serves approximately 700 customers in the Woodstock area.

However, in making its finding, the OEB considered the benefits of Woodstock operations, including Woodstock service personnel, being consolidated in an operating centre in Woodstock.

Regarding customer service, the OEB accepts Hydro One's evidence that those customer service issues arose from a new billing system and have now largely been resolved. Hydro One is required to maintain service quality and service levels in accordance with various codes, rules and other regulatory requirements. It is the OEB's compliance group that deals with Hydro One and service standards. The OEB expects Hydro One to report to the OEB the information set out in Schedule 6.9 of the Share Purchase Agreement[6]as part of its application for new rates for the existing Woodstock customers

In imposing this requirement, the OEB wishes to ensure that reliability and customer service performance are maintained and subject to continuous improvement. Discrete reporting of the statistics set out in Schedule 6.9 will allow the OEB to track these measures. Given that the Share Purchase Agreement contemplates the collection of this data, compliance with this condition should not prove onerous for Hydro One.

Financial Viability

The purchase price to be paid by Hydro One is $46.2 million. This price includes a premium of approximately $20.2 million above the $26 million net book value of Woodstock's assets.

Hydro One gave evidence that the premium paid will not be recovered through rates and will not impact any future revenue requirement. Hydro One submitted that the proposed transaction will not have a material impact on Hydro One's financial position as the total purchase price is approximately 1% of the value of Hydro One's net fixed assets. OEB staff agreed with Hydro One's assertions based on the evidence presented; no submissions were made by other parties.

OEB Findings

The OEB has indicated in the Combined Decision that it will not make a finding with respect to the appropriateness of the purchase price paid for the assets that are proposed to be transferred in the consolidation transaction. That is outside the scope of the OEB's review. However, the OEB does consider whether the amount of the purchase price would affect rates or financial viability of the acquiring entity. The OEB accepts Hydro One's evidence that the premium paid above net book will not have a

[6] Hydro One Inc./Woodstock Hydro Services Inc. Application EB-2014-0213-Exhibit A, Tab 3, Schedule 1, Attachment 6

significant impact on Hydro One's financial viability. The OEB also notes Hydro One's confirmation that the premium paid will not be recovered through rates.

Conservation and Demand Management (CDM)

SEC and Concerned Citizens submitted that Hydro One has not demonstrated that it has a plan to continue the strong CDM performance of Woodstock and raised concern that CDM performance is therefore likely to deteriorate.

Hydro One has committed to continuing to offer CDM. Its evidence is that it will adopt the best of the Woodstock CDM programs in addition to continuing to offer Hydro One programs.

OEB Findings

The submissions of SEC and Concerned Citizens indicate a very active level of interest and engagement of the community in the Woodstock service area with respect to CDM. Hydro One has committed to continuing to offer CDM but its evidence indicates that it has not done any concrete planning with respect to CDM for the Woodstock service area.

As indicated in the 2015-2020 CDM Guidelines (issued on December 19, 2014), it is now the IESO rather than the OEB that has the mandate to review CDM results from individual distributors. However, as indicated above, in determining whether the no harm test has been met, the OEB needs to consider the objective in s 1(3) of the OEB Act:

> To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario.

Accordingly, the OEB will require Hydro One to report one year following the closing of the transaction on which existing Woodstock CDM programs it has eliminated or added to and the reasons why.

4.2 Rate-making Associated with Consolidation

As indicated earlier, the OEB set out its policies on rate-making associated with consolidation in two reports, the 2007 Report and the 2015 Report. On May 22, 2015, Hydro One amended the rate relief sought through the application so as to seek the benefit of the additional elements in the OEB's policy as set out in the 2015 Report.

Deferral of Rate Rebasing

The 2007 Report permitted the deferral of rate-rebasing for up to five years from the closing of a transaction during which time efficiency gains due to consolidation were expected to offset transaction costs. However, the 2015 Report indicated that the OEB would be open to extending the rate rebasing deferral period for up to 10 years after the closing of the transaction This potential extension is intended to encourage consolidation by providing additional time for distributors to recover transaction costs, if appropriate given the circumstances of their individual transactions.

Hydro One has proposed to defer rate rebasing for distribution rates in the Woodstock service area for up to ten years from the closing date of the proposed transaction.

OEB staff argued that consideration of Hydro One's proposal for the deferral of rate rebasing for Woodstock rates is a complex issue. It involves not only this application, but also Hydro One's current cost of service rates term, which ends in 2017, and the OEB's approval of a 5 year deferral for Haldimand and Norfolk. OEB staff submitted that given these circumstances it is more appropriate that the length of the deferral period be examined in Hydro One's next rate application rather than in this proceeding.

Woodstock argued that OEB staff's suggestion creates a significant amount of commercial uncertainty.

SEC submitted that the deferred rebasing period approved should be for a fixed term of ten years from closing of the transaction, unless Hydro One can demonstrate at the time of an earlier application that there has been a material change in circumstances that justifies an earlier rebasing so that the Woodstock ratepayers would have the benefit of rate certainty for 10 years.

Hydro One submitted that the 2015 Report states that there is no requirement for the consolidated entity to wait until the deferred rebasing period is completed to apply to the OEB for rebasing.

OEB Findings

The OEB is not prepared to grant the request by Hydro One to defer rate rebasing for distribution rates in the Woodstock service area for up to ten years from the closing date of the proposed consolidation transaction.

The OEB denies the request for two reasons. First, the evidence to support the request is insufficient. The transaction was negotiated on the basis of a five year deferral period. The original application as filed was on the basis of five years. No evidence was filed to demonstrate that the business case changed and therefore more time was necessary to recover the transaction costs. Testimony at the hearing confirmed that the business case has not changed. Second, the OEB is not satisfied that Hydro One has presented an earning sharing mechanism (ESM) that would protect the interests of ratepayers if the maximum deferral period was allowed as set out in the 2015 Report. The OEB will consider each of these elements in turn.

The purpose of the 2015 Report, in allowing for a potential 10 year deferral period, is to incent parties to enter into consolidation transactions in situations where a five year deferral period would be unlikely to provide sufficient time to recover transaction costs through productivity gains. The 2015 Report acknowledges that "distributors stated that it may take anywhere from six to ten years to reach a break-even point, where the cumulative savings exceed the cumulative acquisition and integration costs"[7] Therefore when an applicant applies to be granted a longer deferral period, the applicant must demonstrate that a longer deferral period is necessary.

The OEB finds that in this application the evidence did not support a conclusion that this was an issue for Hydro One particularly as the application had been filed under the 2007 OEB policy and was amended following the close of the first part of the hearing. Hydro One filed very little evidence in support of the amended application seeking a longer deferral period and no evidence that unless the extended deferral period was granted there would be a barrier to consolidation. Evidence that was supplied was general in nature. The submission was made that additional time would allow transaction costs to be recovered over a longer period of time. The expectation of the OEB is that the applicant will provide the OEB with specific evidence as to why the deferral is necessary in the specific transaction. General statements do not help the OEB assess whether a need for an extended period is warranted.

[7] “Rate-making Associated with Distributor Consolidation" issued March 26, 2015 (the 2015 Report), p. 5

The OEB in seeking more specific evidence as to how circumstances might have changed to warrant a further period of five years to recoup transaction costs, asked Hydro One how the business case for the proposed transaction had changed. Hydro One confirmed at the oral hearing that the business case for the consolidation, which was based on a five year deferral period, has not changed since the request for a five year deferral period was made. With little or no evidence to support the further five year deferral period, the OEB finds that the need for a 10 year deferral period has not been demonstrated.

Woodstock asked the OEB to confirm that the extended deferral period applies to all electricity distributors that have either already undergone a consolidation transaction or who may enter into a sale, merger or amalgamation transaction in the future. The OEB finds that while the relief outlined in the 2015 Report is available, applicants must justify a 10 year deferral period.

Earnings Sharing Mechanism (ESM)

As set out previously, the 2015 Report requires consolidating distributors who request a deferred rebasing period of greater than five years to implement an ESM. Hydro One has committed to implement an ESM of 50:50 sharing with customers where Hydro One's return on equity (ROE) is greater than 300 basis points above the allowed ROE for Hydro One.

SEC argued that under this proposal, as Hydro One has never earned more than 300 basis points over the OEB-approved ROE, and is unlikely ever to do so, the purpose of the OEB's policy - to ensure that ratepayers benefit from the efficiencies generated - would be thwarted in the case of all Hydro One transactions.

SEC argued that while the wording of the 2015 Report does suggest that all customers of the consolidated entity should share in the earnings sharing, in SEC's view, this is not consistent, in this case, with the intention of the policy. SEC submitted that the Board should make clear in its decision that it is the earnings relative to the Woodstock service territory, calculated on a stand-alone basis, that should be subject to earnings sharing.

The OEB further notes that the proposed ESM was not supported by the intervenor group representing ratepayers. When asked by the OEB why the ESM was being applied to all Hydro One customers and not just the Woodstock customers, Hydro One replied that the ESM is spread across all of its customers, because it can only calculate an ROE for the consolidated entity.

OEB staff submitted that following the 18 month period provided for the completion of the consolidation transaction, an ROE can only be calculated for the consolidated entity as Woodstock will cease to exist as a stand-alone entity.

OEB Findings

The OEB considers that the proposed ESM does not meet the intent of the policy outlined in the 2015 Report. The 2015 Report specifically states that the OEB believes that the requirement to include an ESM will address ratepayer concerns that accumulated savings achieved over a potential 10 year period could result in a windfall for shareholders. An ESM which equally divides potential savings between ratepayers and the utility was meant to alleviate this concern.

The OEB is concerned that the ESM as proposed by Hydro One would not ensure that potential savings would be seen by existing customers within the Woodstock service territory. While Hydro One's interpretation of the OEB's policy may be technically compliant with some of the 2015 Report, the OEB is concerned that in this situation, the proposal put forward by Hydro One would not meet the intent of the 2015 Report. Hydro One testified that it had never achieved returns that would trigger the ESM. An ESM that has virtually no chance of being actualized does not in the OEB's view, constitute a satisfactory ESM. There must be a workable ESM in place that will achieve the purpose of protecting ratepayer interests.

Requests for Incremental Capital Module (ICM)

The OEB previously approved Woodstock's request for the extension of its ICM rate rider relating to the Commerce Way Transformer Station until rates are rebased in 2020 or until such other date as may be approved by the OEB, and to true-up the balance at the time of rebasing.

SEC raised a concern that the extension of this rate rider until the next rebasing of rates for Woodstock would result in an over-collection, if the OEB approved Hydro One' s proposal to defer rebasing of Woodstock up to ten years.

In response to SEC's concern, Hydro One submitted that upon closing, it would review the ICM rate rider, assess the balance on the account and determine the required timeframe of the rider. Hydro One would then make a separate application to the OEB to adjust the ICM rate rider, if necessary.

It is clear from the evidence that if a 10 year deferral were granted, and the ICM rate rider was extended to years 6 through 10, there would be a significant over collection. This would be a significant issue for the OEB to consider if a 10 year deferral period were approved at this time.

The OEB is not rejecting the request for an extended deferred rebasing period on the basis of the ICM. However, the OEB notes that ICM extension for years 6-10 as proposed by Hydro One in its amended application did not meet the intent of the 2015 Report. Neither the 2015 Report nor the OEB policy on ICMs supports proposals that lead to significant over-recovery.

Rate Setting and Rate Harmonization

Hydro One has committed to freeze Woodstock's base electricity distribution delivery rates for a period of five years from closing of the MAAD transaction[8], and also to apply a rate rider which results in a 1% reduction on base distribution delivery rates for that period. At the commencement of year 6, Hydro One has proposed that Woodstock's base distribution delivery rates be set according to the OEB's Price Cap Index formula, applied to the Woodstock 2014 base delivery rates (i.e. the rates prior to making the 1% reduction).

OEB staff submitted that the Price Cap Index formula should be applied to the base delivery rates, after deducting the 1%, arguing that to do otherwise would increase rates in 2020 beyond the rate of inflation. SEC agreed with OEB staff.

Concerning Hydro One's rates, SEC argued that according to the 2015 Report Hydro One, once it finishes its current Custom IR plan in 2018, will go on Price Cap IR for years 4-10. Hydro One argued that the intent of the policy is to provide distributors with the flexibility to manage their own unique circumstances and that Hydro One should not be forced to pursue Price Cap IR for years 4 to 10 due to an MAAD application.

Concerning harmonization of the rates of the elements of the consolidated entity, Hydro One stated that it has not decided whether Woodstock customers will be integrated into an existing Hydro One rate class or put into a newly-created rate class for Woodstock customers. Hydro One submitted that whichever approach is adopted rates will reflect the actual cost to serve Woodstock customers, including the anticipated productivity gains resulting from consolidation.

[8] Merger, Acquisition, Amalgamation, Divestiture (MAAD)

OEB Findings

The OEB approves Hydro One's proposal to freeze Woodstock's base electricity distribution delivery rates for a period of five years from closing of this transaction, and the application of a rate rider which results in a 1% reduction on base distribution delivery rates for that period.

The OEB has not approved the deferral period beyond five years and therefore need not consider the treatment of the 1% rate reduction in years 6-10. However, the OEB notes that Hydro One's proposal would have raised a significant issue if the OEB had approved a deferral period of up to ten years. The OEB notes, among other things, that terms of the transaction, including the 1% reduction in rates for five years, were negotiated between the parties with the expectation that rates would be rebased after five years.

The OEB also does not need to consider the issue of what rate plan Hydro One would follow under the 2015 Report, given that it has not approved an extended deferral period. However, the OEB notes that the parties have raised significant issues in this regard.

5 OTHER REQUESTED APPROVALS

As part of these applications, Hydro One requested OEB approval to:

- Continue to track costs to the deferral and variance accounts currently approved by the OEB for Woodstock and to seek disposition of their balances at a future date
- Utilize USGAAP for Woodstock financial reporting.

OEB staff supported the granting of these requested approvals if the OEB approves the consolidation transaction. OEB staff indicated that similar requests were granted in prior proceedings[9].

OEB Findings

The OEB grants approval to continue to track costs to the deferral and variance accounts currently approved by the OEB for Woodstock and to seek disposition of their balances at a future date The OEB accepts Hydro One's argument for the utilization of US GAAP for financial reporting and grants this request.

[9] Hydro One Inc./Norfolk Power Distribution Inc. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. EB-2014-0244

6 CONCLUSION AND DECISION

The OEB concludes that the consolidation proposed in the applications satisfies the no harm test, subject to the conditions set out below. The OEB approves the applications subject to the following conditions:

- That Woodstock transfer its distribution assets to Hydro One within 18 months of the date of this decision

- That Hydro One reports on the following, until Hydro One applies for new rates for existing Woodstock customers:

    a) All costs (including overhead corporate costs) associated with serving the Woodstock service area, recorded and reported both on an annual and cumulative basis from the time of the closing of the share purchase transaction
    b) Actual savings achieved (being the difference between the total costs in a) and the costs of Woodstock as a stand-alone utility)
    c) Indication of how those savings have or will be allocated

- That Hydro One reports to the OEB on the statistics as set out in Schedule 6.9 of the Share Purchase Agreement as part of its next rate application.

- That Hydro One reports to the OEB specific details regarding the CDM programs that it offers in the Woodstock service area post transaction. The reporting shall be in the form of a letter to the OEB filed one year after the close of the transaction setting out the programs that were offered in the previous year and include a list of CDM programs that were discontinued and the reasons for the discontinuance.

Woodstock is granted inclusion of a rate rider in its 2014 OEB approved rate schedule to give effect to a 1% reduction relative to 2014 base electricity delivery rates (exclusive of rate riders) under section 78 of the Act.

The OEB's approval of Woodstock's proposal for a 1% reduction relative to 2014 base electricity delivery rates results in changes to Woodstock's approved Tariff of Rates and Charges (EB-2013-0182). The OEB requires Woodstock to file a draft Rate Order, reflecting the OEB's findings in this proceeding, as outlined below. The draft Rate Order shall include a proposed effective and implementation date.

7 ORDER

THE OEB ORDERS THAT:

1) Hydro One Inc. is granted leave to acquire all of the issued and outstanding shares of Woodstock Hydro Holdings Inc.

2) The applicants shall promptly notify the OEB of the completion of the transaction referred to in paragraph 1 above.

3) Woodstock is granted leave to transfer its distribution system to Hydro One.

4) The applicants shall promptly notify the OEB of the completion of the transaction referred to in paragraph 3 above.

5) Once the notice referred to in paragraph 4 is provided to the OEB, the OEB will transfer Woodstock's electricity distribution licence ED-2003-0011 and Woodstock's Rate Order to Hydro One.

6) The leave granted in paragraphs 1 and 3 above shall expire 18 months from the date of this Decision and Order.

7) Hydro One is granted approval to use US GAAP for regulatory accounting purposes, in relation to Woodstock, following the closing of the transaction referred to in paragraph 1 above.

8) Woodstock is granted inclusion of a rate rider in its 2014 OEB approved rate schedule to give effect to a 1% reduction relative to 2014 base electricity delivery rates (exclusive of rate riders) under section 78 of the Act.

9) Hydro One is granted approval to continue to track costs to the deferral and variance accounts currently approved by the OEB for Woodstock and to seek disposition of their balances at a future date.

10) Hydro One shall report on the following:

    a) All costs (including overhead corporate costs) associated with serving the Woodstock service area, recorded and reported both on an annual and cumulative basis from the time of the closing of the share purchase transaction

b) Actual savings achieved (being the difference between the total costs in a) and the costs of Woodstock as a stand-alone utility)
c) Indication of how those savings have or will be allocated

11) Hydro One shall report to the OEB on the metrics as set out in the Schedule 6.9 of the Share Purchase Agreement as part of its next rate application.

12) Hydro One shall report to the OEB specific details regarding the CDM programs that it offers in the Woodstock service area post transaction. The reporting shall be in the form of a letter one year after the close of the transaction setting out the programs that were offered in the previous year and include a list of CDM programs that were discontinued and the reasons for the discontinuance

13) Woodstock shall file with the OEB, and shall also forward to intervenors, a draft Rate Order that includes a proposed Tariff of Rates and Charges reflecting the OEB's findings in this Decision and Order by **September 21, 2015**.

14) Intervenors and OEB staff shall file any comments on the draft Rate Order with the OEB and forward to the applicants by **September 28, 2015**.

15) The applicants shall file with the OEB and forward to intervenors responses to any comments on the draft Rate Order by **October 5, 2015**.

16) Eligible intervenors shall file with the OEB and forward to the applicants their respective cost claims no later than 7 days from the date of issuance of the final Rate Order.

17) The applicants shall file with the OEB and forward to the intervenors any objections to the claimed costs of the intervenors within 17 days from the date of issuance of the final Rate Order.

18) Intervenors shall file with the OEB and forward to the applicants any responses to any objections for cost claims within 24 days from the date of issuance of the final Rate Order.

19) The applicants shall pay the OEB's costs of, and incidental to, this proceeding immediately upon receipt of the OEB's invoice.

All filings to the OEB must quote file number EB-2014-0213 and be made electronically through the OEB's web portal at www.pes.ontarioenergyboard.ca/eservice/ in searchable/unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS

Ontario Energy Board
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DATED at Toronto September 11, 2015

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

	$M	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	Total %	5 Year Deferal	5 Year %
GLPT Capital Expenditure Forecast Without Transaction		19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8	**183.3**		**89.3**	
Capital Expenditure Forecast With Transaction Showing Base and High Potential Cost Scenarios	Base	19.4	16.2	14.7	14.1	15.3	17.6	16.9	17.8	16.9	17.3	**166.2**		**79.7**	
	High	19.4	16.2	13.2	12.7	13.8	15.8	15.2	16.0	15.2	15.6	**153.1**		**75.3**	
Forecast Capital Savings	Base	0.0	0.0	2.9	4.5	2.2	3.0	3.0	0.5	0.5	0.5	**17.1**	9.33%	**9.6**	10.75%
	High	0.0	0.0	4.4	5.9	3.7	4.8	4.7	2.3	2.2	2.2	**30.2**	16.48%	**14.0**	15.68%
GLPT OM&A Cost Forecast Without Transaction	OM&A	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.4	13.7	**125.6**		**59.7**	
OM&A Cost Forecast With Transaction Showing Base and High Potential Cost Scenarios	Base	11.5	11.7	10.7	11.0	11.2	11.4	11.6	11.4	11.6	11.8	**113.9**		**56.1**	
	High	11.5	11.7	8.3	8.5	8.7	8.9	9.0	8.7	8.9	9.1	**93.3**		**48.7**	
Forecast OM&A Savings	Base	0.0	0.0	1.2	1.2	1.2	1.3	1.3	1.8	1.8	1.9	**11.7**	9.32%	**3.6**	6.03%
	High	0.0	0.0	3.6	3.7	3.7	3.8	3.9	4.5	4.5	4.6	**32.3**	25.72%	**11.0**	18.43%

(Exhibit A, Tab 2, Schedule 1, p.4-7)

Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements For
Electricity Transmission Applications

Chapter 2

Revenue Requirement Applications

February 11, 2016

Chapter 2 Filing Requirements for Revenue Requirement Applications

2.0 Introduction

The filing requirements contained in this chapter outline the minimum information necessary for a transmission revenue requirement application. Applicants should review Chapter 1 of this document, which provides an overview of the OEB's expectations on certain generic matters, such as the completeness and accuracy of an application, the exploration of non-material items, and confidential filings.

On October 18, 2012, the OEB released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Report). While the RRFE Report related specifically to electricity distributors, the OEB stated that "[i]n due course, the OEB will provide further guidance regarding how the policies in this Report may be applied to transmitters." The changes to the filing requirements in this document provide the initial steps toward the integration of core RRFE concepts into the rate application process for transmitters.

In the RRFE Report the OEB provided electricity distributors with three rate-setting methods: 4th Generation Incentive Rate-setting (now called Price Cap IR), Custom Incentive Rate-setting and Annual Incentive Rate-setting Index. As a move toward greater adoption of an incentive- and performance-based rate setting framework for transmitters, the OEB has created two new transmission revenue plan options:

- A custom incentive-rate setting plan, which will consist of a transmitter-specific revenue trend for the plan term, which shall be not less than five years (Custom IR)
- An incentive-based revenue index plan of five years, comprising an initial application to establish a revenue requirement based on a single test year cost of service application, followed by incentive-based and indexed adjustments to revenue requirement for the balance of the term. Analogous to a Price Cap for distributors, this "Revenue Cap index" approach includes expectations for the development of an index, as well as productivity and stretch commitments. The OEB invites transmitters to propose and substantiate the appropriate method and commitments for these elements.

Category	Revenue Cap index	Custom IR
Going-in rates	Determined in single forward test-year cost of service review	Determined in multi-year application review
Form	Index: Revenue Cap option	Custom Index
Coverage	Comprehensive	Comprehensive
Annual adjustment – inflation	To be proposed; any deviation from OEB inputs to be justified	Transmitter-specific revenue requirement trend for the plan term to be determined by the OEB, informed by: (1) the transmitter's forecasts (revenue and costs, inflation, productivity); (2) the OEB's inflation analysis; and (3) internal and external benchmarking to assess the reasonableness of the transmitter's forecasts
Annual adjustment – productivity	Productivity and stretch factor expected	
Benchmarking	Both internal (against own cost performance over time to demonstrate continuous improvement) and external (against other transmitters), including rationale for selected comparators	
Sharing of benefits	Stretch and/or productivity factor to be proposed	Case-by-case
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years
Capital module	Option for capital factor proposals	N/A
Unforeseen events	Z-factor available	Z-factor available
Deferral and Variance Accounts	Status quo	Status quo + case-by-case
Performance Reporting and Monitoring	Draft scorecard, RRR filings & case-by-case	Draft scorecard, RRR filings & case-by-case

As indicated in the introduction, transmitters have the option, for their first application after these filing requirements are issued, to apply to have revenue requirement set for one or two years through a cost of service application.