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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 43(1) of the Ontario Energy Board Act, 1998, for an order or orders granting leave to amalgamate as of January 1, 2019;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 36 of the Ontario Energy Board Act, 1998, for an order or orders approving a rate setting mechanism and associated parameters during the deferred rebasing period, effective January 1, 2019.

OEB STAFF
CROSS-EXAMINATION COMPENDIUM
Panels 1 and 2

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Ontario

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

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

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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

[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. *Implementing public policy requirements for promoting conservation, facilitating a smart grid and promoting renewable energy sources*

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. *Prices not related to a utility's own costs*

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 up to 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).

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

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 –

TAB 2

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.

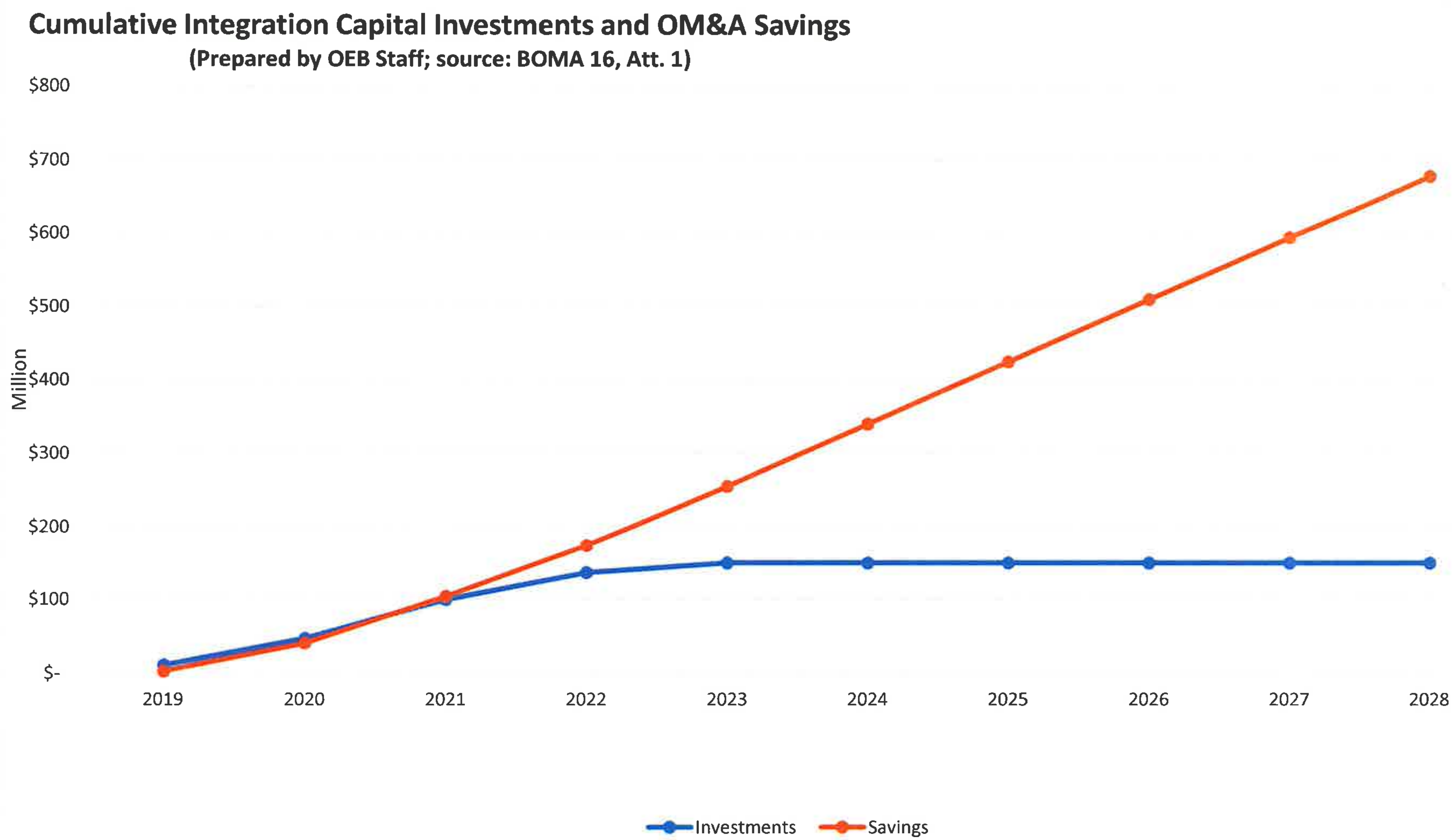
1. Allow consolidating entities to choose a deferred rebasing period of up to 10 years after the closing of the transaction. Those consolidating entities that elect a re-basing period of only up to five years may do so as set out under the current policy.

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.

TAB 3


Cumulative Integration Capital Investments and OM&A Savings
(Prepared by OEB Staff; source: BOMA 16, Att. 1)
$800
$700
$600
$500
$400
$300
$200
$100
$-
Million
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Investments
Savings

TAB 4

Appendix A: Capital Investment and High Level Estimated O&M Savings for Utility Integration

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Utility Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	$ 11	$ 36	$ 53	$ 37	$ 13	$ -	$ -	$ -	$ -	$ -	$ 150
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Utility Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	$ -	$ 38	$ 51	$ 53	$ 53	$ 85	$ 85	$ 85	$ 85	$ 85	$ 620
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	$ 3	$ 38	$ 63	$ 70	$ 81	$ 85	$ 85	$ 85	$ 85	$ 85	$ 680

TAB 5

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List No.1

Question:

Please provide all internal documents generated by Enbridge Inc., Enbridge Gas Distribution and Union Gas that examined, quantified or hypothesized about the impact of keeping the two utilities separate or merged.

a. Please include any document that include estimates of the rate impacts, revenue requirement and/or profitability of rebasing for either utility.
b. If the Board were to order a high-level examination of the scenario of the two utilities re-basing, what is the applicant's estimate of the cost of hours to generate and the time frame for which an evidence-based quality forecast to be generated?

Response:

a) The following attachments represents the internal documentation regarding the amalgamation:
   - Attachment 1: October 31, 2017 EGD, Union Gas and Enbridge Inc. Board of Directors presentation
   - Attachment 2: July 25, 2017 EGD, Union Gas and Enbridge Inc. Board of Directors memorandum
   - Attachment 3: November 15, 2017 EGD, Union MAADs & PCRMM Stakeholder Day presentation

b) The time and effort associated with preparing a rebasing application is significant as it involves a detailed examination of revenues and costs; rebasing cannot be done at a high level. The preparation of an application and evidence for rebasing takes approximately 18 months. Once the application and evidence are filed, the regulatory process takes approximately one year.

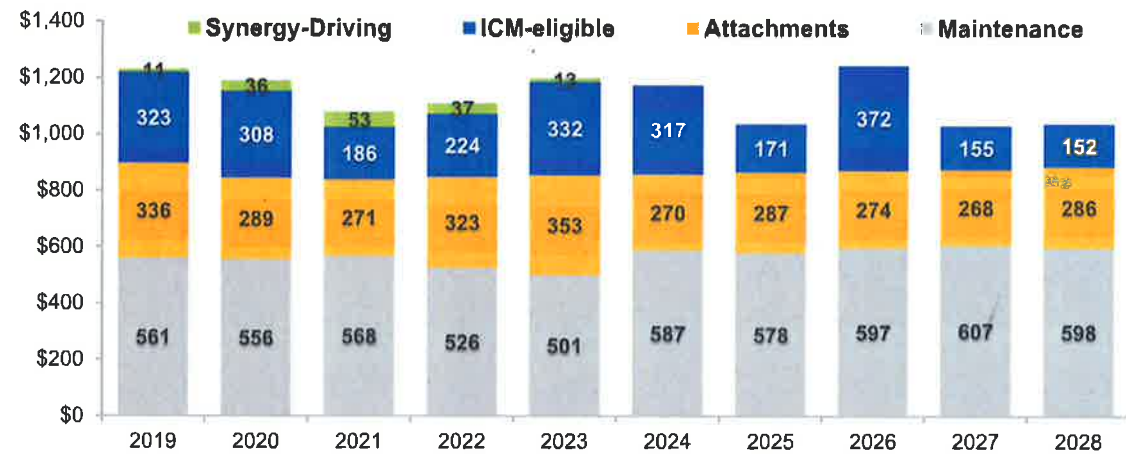
Integration Financial Evaluation

ENBRIDGE

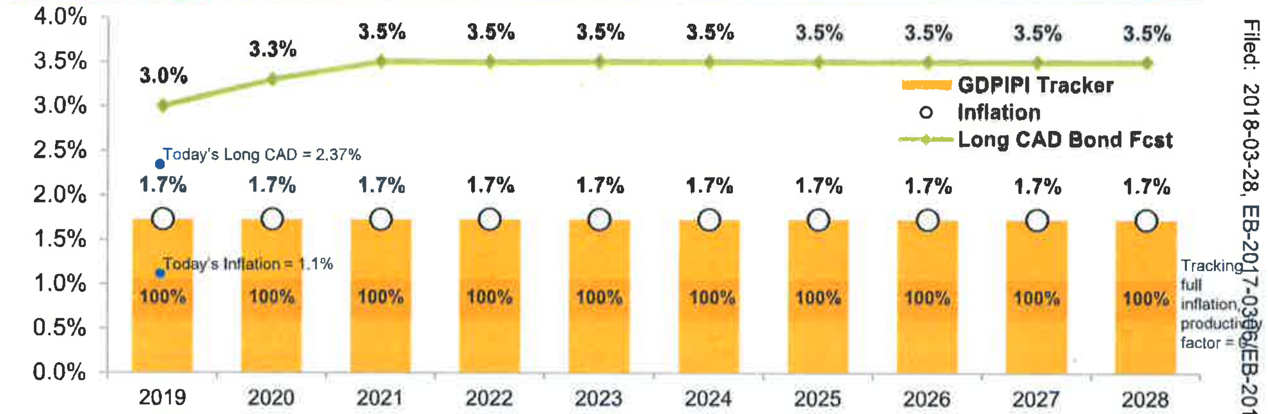
Base Case Key Economic Assumptions

- Capital expenditures based on 10 year Asset Management Plans which is filed at base year; Incremental Capital (discrete projects) added to rate base at in service year Allowed ROE amounts through the ICM
- The Long CAD Bond forecast has a 50 bps increase from 2019 to 2021 and 113 bps increase from todays rate to 2021
- Allowed ROEs are based on utility forecast which is primarily driven by the Long CAD Bond
- Zero cost sharing assumed over the 10 year period (i.e. Returns on equity are less than the 300 bp threshold)

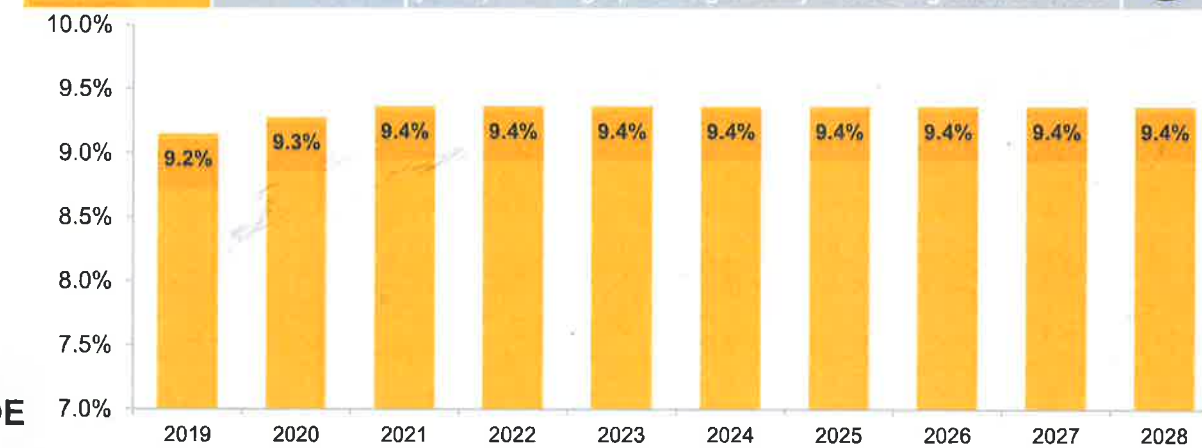
Capital Program	Outlook Stable	Stable & manageable profile, combined with ICM, reduces risks to ROE drag



Inflation & Interest Rates	Outlook ST Increase	Historic low interest rate environment trending higher, partially offset by GDPIPI revenue tracking and hedging



Allowed-ROE	Outlook Stable	Allowed-ROE drivers (LT CAD GOV, Corporate bond yields) trending upward, gradually increasing allowed-ROE



No rate adjustment under MAADs for higher interest rates or Allowed ROE

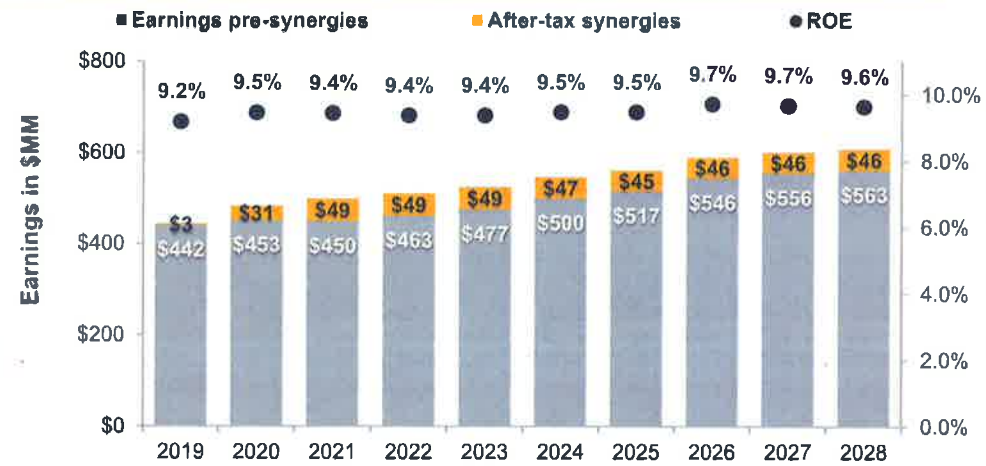
Integration Financial Evaluation

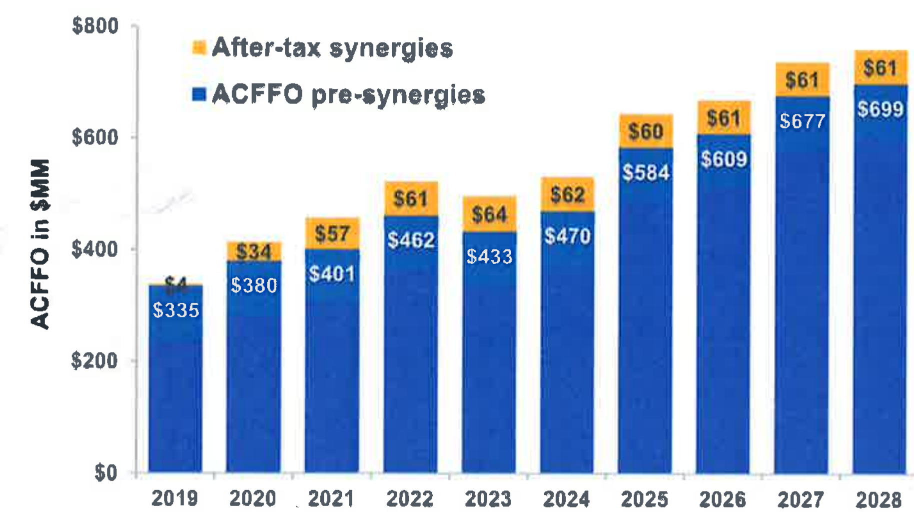
Base Case Financial Summary

ENBRIDGE

Financial Summary

	Proposed Filing: 10 year MAADS (Escalated Price Cap + Incremental Capital Module)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
EGD	235	245	240	247	256	272	278	304	309	316	
UGL including deferred tax adj	207	208	210	215	220	228	238	242	247	247	
Utility Earnings before synergies	**442**	**453**	**450**	**463**	**477**	**500**	**517**	**546**	**556**	**563**	
											Total
Synergies	3	38	63	70	81	85	85	85	85	85	**680**
Drag due to funded synergy capital	(1)	(4)	(9)	(15)	(18)	(18)	(18)	(17)	(17)	(16)	**(133)**
Sub-Total Pre-Tax Synergies	2	34	54	55	63	67	67	68	68	69	**547**
After-tax impact of synergies	**3**	**31**	**49**	**49**	**49**	**47**	**45**	**46**	**46**	**46**	**412**
Utility Earnings with synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
Earnings Sharing (2024 – 2028 >300bps)	-	-	-	-	-	0	0	0	0	0	
Utilities Earnings after sharing	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
Achieved ROE	9.2%	9.5%	9.4%	9.4%	9.4%	9.5%	9.5%	9.7%	9.7%	9.6%	
Allowed ROE	9.2%	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	





Average of $42 Million/ year of after –tax synergies provides opportunity to achieve earnings in excess of Allowed ROE while delivering inflationary rate increases to customers

[1] ACFFO is aligned with utility STIP measurement calculation method and has been grossed up (pre-tax and interest expense)
[2] Capital structure 36% equity/ 64% debt
[3] Income tax rates constant at 26.5%

TAB 6

Scenario 1: ***ICM revenue requirement calculated based on first year of introduction (current ICM policy and standard CoS approach)***

Years	Depreciation Rate	Debt Rate		ROE		Tax Rate
33	3.03%	5%	65%	9.25%	35%	26.25%

		Opening NBV	Closing NBV	Average NBV	Debt Cost ($M)	ROE	Tax (grossed up)	Depreciation	Revenue Requirement	Change in Revenue Requirement: Year over year change	Change in Revenue Requirement: Change from the start
Year 1	2019	100.000	96.970	98.485	3.201	3.188	1.135	3.030	10.554		
Year 2	2020	96.970	93.939	95.455	3.102	3.090	1.100	3.030	10.323	2.2%	2.2%
Year 3	2021	93.939	90.909	92.424	3.004	2.992	1.065	3.030	10.091	2.2%	4.4%
Year 4	2022	90.909	87.879	89.394	2.905	2.894	1.030	3.030	9.860	2.3%	6.6%
Year 5	2023	87.879	84.848	86.364	2.807	2.796	0.995	3.030	9.628	2.3%	8.8%
Year 6	2024	84.848	81.818	83.333	2.708	2.698	0.960	3.030	9.397	2.4%	11.0%
Year 7	2025	81.818	78.788	80.303	2.610	2.600	0.925	3.030	9.165	2.5%	13.2%
Year 8	2026	78.788	75.758	77.273	2.511	2.502	0.890	3.030	8.934	2.5%	15.4%
Year 9	2027	75.758	72.727	74.242	2.413	2.404	0.856	3.030	8.702	2.6%	17.5%
Year 10	2028	72.727	69.697	71.212	2.314	2.305	0.821	3.030	8.471	2.7%	19.7%
					Revenue requirement over 10 years (2019-2028)				**95.126**		

Scenario 1: ***ICM revenue requirement calculated based on first year of introduction (current ICM policy and standard CoS approach)***

Year 1	2019	100.000	96.970	98.485	3.201	3.188	1.135	3.030	10.554

2019-2028 Period (Cumulative)

	Revenues from ICM Rate Rider	Actual Revenue Requirement	Over-collection	
	$M	$M	$M	%
Based on year 1 (2018) incremental revenue requirement X 10 years	105.544	**95.126**	10.418	11.0

Scenario 2: ***ICM revenue requirement calculated based on average NBV from first year of introduction up until rebasing***

ICM Rev Reqt, if based on average NBV over period	100.000	69.697	84.848	2.758	2.747	0.978	3.030	9.513

2019-2028 Period (Cumulative)

	Revenues from ICM Rate Rider	Actual Revenue Requirement	Over-collection	
	$M	$M	$M	%
Based on average NBV incremental revenue requirement X 10 years	95.126	**95.126**	-	-

TAB 7

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

MAADs Issues List – Issue No. 1

Reference: Exhibit B, Tab 1, p. 40

Preamble:

Internal processes will be developed to maintain the fairness and confidentiality of the bidding process used for Amalco procurement of storage services either from third parties or from the unregulated assets of Amalco.

Question:
Please confirm that the noted passages describes a process wherein Amalco will, possibly, bid for storage services from itself? If confirmed please explain under what circumstances this could arise and how it would work.

Response:

Just as EGD receives storage services from Union today, which contracts are listed, described and provided in response to SEC Interrogatory#2 found at Exhibit C.SEC.2, Amalco will continue to require purchased market based storage services post-amalgamation in addition to the 91.3 BCF (99.4 PJ) of EGD cost based utility storage. Amalco will look at storage and storage alternatives available in the competitive market to secure this additional capacity. Amalco is one of the parties that can provide storage services in the competitive market. To ensure an unbiased storage procurement process, Gas Supply personnel will conduct a blind request for proposal ("RFP") through an independent third party for storage capacity. EGD has recently utilized this process to secure storage services with Deloitte and Touche acting as the independent third party.

The independent third party communicates with RFP participants and completes an objective matrix of criteria for evaluating RFP responses. The results will be presented to Gas Supply without bidder identification and in a manner consistent with the evaluation matrix. This will allow for evaluation and selection of the most appropriate storage services on the basis of the object criteria.

TAB 8

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Charleson
To Mr. Quinn

REF: Tr.3 p.104.

To provide a version of the matrix for evaluation of bids in the blind tender process

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Response:

Please see the attached matrix that has been redacted to remove commercially sensitive information.

EGD Storage RFP matrix 1

EGD defined terms:

**Up to 5 years of service commencing April 1, 2018*

**Firm Injection Schedule: at a minimum, must include the months of May through September*

**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*

**Firm Injection Curve rights: at least 0.75% of MSB per day when inventory is less than 75% full*

**Firm Withdrawal Curve rights: at least 1.2% of MSB per day when inventory is more than 25% full*

Counterparty (BLIND)	*Company A*	*Company B*	*Company C*	*Company C*	*Company C*	*Company C*
offer descriptor (ie 1 of 3)	*1 of 1*	*1 of 1* *Standard LST Service*	*1 of 12*	*2 of 12*	*3 of 12*	*4 of 12*
TERM (years)	3	2-5 Years	1	2	3	1
Start date	4/1/2018	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Union-Dawn	Union-Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	Up to 8,000,000 GJ	2,000,000	2,000,000	2,000,000	2,000,000
Heat Value		N/A	mmbtu	mmbtu	mmbtu	mmbtu
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1 If any above line item is not applicable, please insert N/A

Counterparty (BLIND)	*Company C*	*Company C*	*Company C*	*Company C*	*Company C*	*Company C*
offer descriptor (ie 1 of 3)	*5 of 12*	*6 of 12*	*7 of 12*	*8 of 12*	*9 of 12*	*10 of 12*
TERM (years)	2	3	1	2	3	1
Start date	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Heat Value	mmbtu	mmbtu	mmbtu	mmbtu	mmbtu	mmbtu
Demand Charge per unit	[redacted]					
Commodity Charge per unit						
Fuel Charge per unit						
Transportation Charge per unit						
Injection Curve parameters/ratchets						
Injection period (firm/interruptible)						
Additional/Enhanced terms						
Withdrawal Curve parameters/ratchets						
Withdrawal period (firm/interruptible)						
Cycling terms (ie unlimited)						
Nomination Windows						
Additional/Enhanced terms						
General Terms and Conditions						
Additional Comments						

Counterparty (BLIND)	***Company C***	***Company C***	***Company D***	***Company D***	***Company D***	***Company D***
offer descriptor (ie 1 of 3)	*11 of 12*	*12 of 12*	*1 of 13*	*2 of 13*	*3 of 13*	*4 of 13*
TERM (years)	2	3	1 year	2 year	3 year	4 year
Start date	1-Apr-18	1-Apr-18	1-May-18	1-May-18	1-May-18	1-May-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	2,000,000	1,000,000 MMBtu	1,000,000 MMBtu	1,000,000 MMBtu	1,000,000 MMBtu
Heat Value	mmbtu	mmbtu	n/a	n/a	n/a	n/a
Demand Charge per unit	[redacted]					
Commodity Charge per unit						
Fuel Charge per unit						
Transportation Charge per unit						
Injection Curve parameters/ratchets						
Injection period (firm/interruptible)						
Additional/Enhanced terms						
Withdrawal Curve parameters/ratchets						
Withdrawal period (firm/interruptible)						
Cycling terms (ie unlimited)						
Nomination Windows						
Additional/Enhanced terms						
General Terms and Conditions						
Additional Comments						

Counterparty (BLIND)	*Company D*	*Company D*	*Company D*	*Company D*	*Company D*	*Company D*
offer descriptor (ie 1 of 3)	*5 of 13*	*6 of 13*	*7 of 13*	*8 of 13*	*9 of 13*	*10 of 13*
TERM (years)	1 year	2 year	3 year	4 year	1 year	2 year
Start date	1-May-18	1-May-18	1-May-18	1-May-18	1-May-18	1-May-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	3,000,000 MMBtu	3,000,000 MMBtu
Heat Value	n/a	n/a	n/a	n/a	n/a	n/a
Demand Charge per unit	[redacted]					
Commodity Charge per unit						
Fuel Charge per unit						
Transportation Charge per unit						
Injection Curve parameters/ratchets						
Injection period (firm/interruptible)						
Additional/Enhanced terms						
Withdrawal Curve parameters/ratchets						
Withdrawal period (firm/interruptible)						
Cycling terms (ie unlimited)						
Nomination Windows						
Additional/Enhanced terms						
General Terms and Conditions						
Additional Comments						

Counterparty (BLIND)	*Company D*	*Company D*	*Company D*	*Company E*	*Company E*	*Company E*
offer descriptor (ie 1 of 3)	*11 of 13*	*12 of 13*	*13 of 13*	*1 of 6*	*2 of 6*	*3 of 6*
TERM (years)	3 year	4 year	3 year	1 year	3 years	5 years
Start date	1-May-18	1-May-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	3,000,000 MMBtu	3,000,000 MMBtu	1,000,000 MMBtu	3,000,000 mmbtu	3,000,000 mmbtu	3,000,000 mmbtu
Heat Value	n/a	n/a	n/a	Per TransCanada Pipelines	Per TransCanada Pipelines	Per TransCanada Pipelines
Demand Charge per unit	[redacted]					
Commodity Charge per unit						
Fuel Charge per anit						
Transportation Charge per unit						
Injection Curve parameters/ratchets						
Injection period (firm/interruptible)						
Additional/Enhanced terms						
Withdrawal Curve parameters/ratchets						
Withdrawal period (firm/interruptible)						
Cycling terms (ie unlimited)						
Nomination Windows						
Additional/Enhanced terms						
General Terms and Conditions						
Additional Comments						

Counterparty (BLIND)	*Company E*	*Company E*	*Company E*	*Company F*	*Company G*
offer descriptor (ie 1 of 3)	*4 of 6*	*5 of 6*	*6 of 6*	*1 of 1*	*1 of 1*
TERM (years)	1 year	3 years	5 years	1	5 years
Start date	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	April 1, 2018
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Injections location: *Company G* Interconnect with Vector/Rover or Nexus. WD location: *Company G*
MSB (max annual storage balance) units: GJ or MMBtu	5,000,000 mmbtu	5,000,000 mmbtu	5,000,000 mmbtu	2.14 Bcf	MSB up to 8 Bcf or equivelent GJ of storage capacity.
Heat Value	Per TransCanada Pipelines	Per TransCanada Pipelines	Per TransCanada Pipelines	N/A	current heat value on injections is approx 1.050
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TAB 9

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Charleson
To Mr. Gluck

REF: Tr.2 p.160

To determine the value of Union Gas marketed regulated storage versus EGD'S contracted regulated storage and its financial impact

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Response:

Please see Table 1 on the following page for the requested hypothetical analysis of the benefit to EGD customers if market-based storage capacity was replaced with Union's cost-based excess utility storage space from 2013 to 2017. Line 5 shows an estimate of the potential benefit that could have accrued to EGD rate zone customers and Line 9 shows the foregone benefit to Union rate zone customers.

In any year, the analysis shows that EGD rate zone customers are better off in this scenario and Union rate zone customers are worse off. The Applicants' position, which maintains the current storage arrangements, is consistent with the no harm test.

Table 1
Comparison of Union's Excess Utility Storage Space Benefit
to EGD Customers and Union Customers

Line No.	Particulars (000's)	2013	2014	2015	2016	2017
		(a)	(b)	(c)	(d)	(e)
	EGD Customer Benefit					
1	Union Excess Utility Storage Space (PJ)	8.6	6.4	5.0	6.4	6.8
2	Average EGD Market-Based Storage Rate ($CAN/GJ) (1)	0.810	0.727	0.665	0.699	0.726
3	EGD's Estimated Market-Based Storage Cost	6,966	4,653	3,325	4,474	4,937
4	Union's Excess Utility Storage Space Cost (2)	3,218	2,331	1,779	2,402	2,489
5	Potential Net Benefit to EGD Customers	3,748	2,322	1,546	2,072	2,448
	Union Customer Benefit					
6	Union Short-Term Firm Peak Storage Revenue (3)	4,747	3,235	4,935	5,627	4,618
7	Union's Excess Utility Storage Space Cost (2)	3,218	2,331	1,779	2,402	2,489
8	Less: Shareholder Incentive	153	90	316	322	213
9	Foregone Net Benefit to Union Customers	1,377	814	2,840	2,902	1,915

Notes:

(1) The average EGD market-based storage rate is calculated as the average rate paid for all market-based storage capacity contracted in each year. The average rate for EGD market-based storage is likely not reflective of what EGD's storage portfolio would have been if Union's excess utility storage space had been made available to EGD in those years.

(2) Attachment 1, line 11, columns (b) - (f).

(3) Attachment 1, line 6, columns (b) - (f).

Customers in Union North and Union South currently receive a net benefit in rates of $4.5 million from the sale of short-term storage and other balancing services. Of this amount, $2.3 million is related to the sale of Union's excess utility storage space as short-term firm peak storage ($7.9 million revenue less $5.6 million of cost and shareholder incentive) and $2.2 million related to the sale of other short-term storage and balancing services ($2.5 million revenue less $0.3 million of shareholder incentive). The difference between the actual net benefit obtained in any year and the net benefit in rates is recorded in the Short-Term Storage Deferral Account (No. 179-70) and is trued up annually as part of the deferral account clearing process. Please see Attachment 1 for the details of Deferral Account 179-70 split out by short-term firm peak storage and other short-term storage and balancing services for the years 2013 to 2017.

For purposes of the requested analysis above, it was assumed only the revenue associated with the short-term firm peak storage service would be replaced by EGD's use of the excess utility storage space and that the net revenue from other short-term storage and balancing services would continue to accrue to Union's ratepayers (less cost and shareholder incentive).

If the Board ordered Amalco to utilize Union's excess utility storage space for EGD in-franchise requirements, consideration would need to be given to the $2.3 million net benefit in Union's rates and the charge to EGD customers for the use of the storage space.

In its NGEIR Decision (EB-2005-0551), the Board determined that Union should be required to reserve 100 PJ (approximately 95 Bcf) of space at cost-based rates for in-franchise customers (p. 83). This capacity met the needs of Union South and Union North customers at the time of NGEIR plus allowed for further capacity (capped at 100 PJ total) to serve the needs of Union North and Union South customers at cost-based rates. The Board also determined that Union will have the flexibility to market the excess utility storage (difference between 100 PJ and the capacity required to meet in-franchise demands in any year) (p. 83) with the entire margin on storage transactions that are underpinned by utility storage space accruing to Union's ratepayers, less an appropriate incentive payment to the utilities (p. 101).

In the Applicant's view, the amalgamation does not impact the NGEIR decision.

UN ON GAS LIMITED
Details of Revenue and Costs and Calculation of Balance
in Short-Term Storage Deferral Account (No.179-70)

Line No.	Particulars ($000's)	Short-Term Firm Peak Storage Board-Approved 2013 (a)	Actual 2013 (b)	Actual 2014 (c)	Actual 2015 (d)	Actual 2016 (e)	Draft Actual 2017 (f)
	Revenue						
1	C1 Off-Peak Storage	-	-	-	-	-	-
2	Supplemental Balancing Services	-	-	-	-	-	-
3	Gas Loans	-	-	-	-	-	-
4	Enbridge LBA	-	-	-	-	-	-
5		-	-	-	-	-	-
6	C1 ST Firm Peak Storage	7,883	4,747	3,235	4,935	5,627	4,618
7	Total Revenue (1)	7,883	4,747	3,235	4,935	5,627	4,618
	Costs						
8	O&M (2)	3,810	2,910	2,161	1,684	2,156	2,289
9	UFG (3)	316	229	92	39	121	90
10	Compressor Fuel (4)	1,201	79	78	56	125	110
11	Total Costs	5,327	3,218	2,331	1,779	2,402	2,489
12	Net Revenue (line 7 - 11)	2,556	1,529	904	3,156	3,225	2,129
13	Less Shareholder Portion (10%)	255	153	90	316	322	213
14	Ratepayer Portion	2,301	1,377	814	2,840	2,902	1,915
15	Approved in Rates	2,301	2,301	2,301	2,301	2,301	2,301
16	Deferral balance payable to/ (collectable from) ratepayers	-	(924)	(1,487)	539	601	(386)

Line No.	Particulars ($000's)	Other Short-term Storage and Balancing Services Board-Approved 2013 (g)	Actual 2013 (h)	Actual 2014 (i)	Actual 2015 (j)	Actual 2016 (k)	Draft Actual 2017 (l)
	Revenue						
1	C1 Off-Peak Storage	500	389	241	603	2,749	709
2	Supplemental Balancing Services	2,000	1,481	752	1,001	1,367	890
3	Gas Loans	-	56	54	38	19	15
4	Enbridge LBA	-	360	237	282	968	381
5		2,500	2,286	1,283	1,925	5,102	1,995
6	C1 ST Firm Peak Storage	-	-	-	-	-	-
7	Total Revenue (1)	2,500	2,286	1,283	1,925	5,102	1,995
	Costs						
8	O&M (2)	-	-	-	-	-	-
9	UFG (3)	-	486	409	239	392	172
10	Compressor Fuel (4)	-	167	350	349	405	210
11	Total Costs	-	653	758	588	797	381
12	Net Revenue (line 7 - 11)	2,500	1,633	525	1,337	4,305	1,614
13	Less Shareholder Portion (10%)	250	163	53	134	431	161
14	Ratepayer Portion	2,250	1,469	473	1,203	3,875	1,452
15	Approved in Rates	2,250	2,250	2,250	2,250	2,250	2,250
16	Deferral balance payable to/ (collectable from) ratepayers	-	(781)	(1,777)	(1,047)	1,625	(798)

Line No.	Particulars ($000's)	Total Board-Approved 2013 (5) (m)	Actual 2013 (6) (n)	Actual 2014 (7) (o)	Actual 2015 (8) (p)	Actual 2016 (9) (q)	Draft Actual 2017 (10) (r)
	Revenue						
1	C1 Off-Peak Storage	500	389	241	603	2,749	709
2	Supplemental Balancing Services	2,000	1,481	752	1,001	1,367	890
3	Gas Loans	-	56	54	38	19	15
4	Enbridge LBA	-	360	237	282	968	381
5		2,500	2,286	1,283	1,925	5,102	1,995
6	C1 ST Firm Peak Storage	7,883	4,747	3,235	4,935	5,627	4,618
7	Total Revenue (1)	10,383	7,033	4,518	6,860	10,729	6,613
	Costs						
8	O&M (2)	3,810	2,910	2,161	1,684	2,156	2,289
9	UFG (3)	316	715	500	278	514	262
10	Compressor Fuel (4)	1,201	246	428	405	530	320
11	Total Costs	5,327	3,871	3,089	2,367	3,199	2,870
12	Net Revenue (line 7 - 11)	5,056	3,162	1,429	4,493	7,530	3,743
13	Less Shareholder Portion (10%)	505	316	143	449	753	374
14	Ratepayer Portion	4,551	2,846	1,286	4,043	6,777	3,368
15	Approved in Rates	4,551	4,551	4,551	4,551	4,551	4,551
16	Deferral balance payable to/ (collectable from) ratepayers	-	(1,705)	(3,265)	(508)	2,226	(1,183)

Notes:
(1) Based on short-term storage services provided.
(2) 2013 O&M revenue requirement based on 1 .3 PJ's of Board-approved excess in-franchise storage capacity.
(3) Total based on short-term storage volumes in proportion to total volumes. Short-Term Firm Peak Storage based on short-term peak storage activity compared to overall short-term storage activity.
(4) Total based on short-term storage activity in proportion to total actual storage activity. Short-Term Firm Peak Storage based on short-term peak storage activity compared to overall short-term storage activity.
(5) EB-2013-0210, Rate Order, Working Papers, Schedule 40, lines 14 - 17.
(6) EB-2014-0145, Exhibit A, Tab 1, Appendix A, Schedule 6.
(7) EB-2015-0010, Exhibit A, Tab 1, Appendix A, Schedule 3.
(8) EB-2016-0118, Exhibit A, Tab 1, Appendix A, Schedule 3.
(9) EB-2017-0091, Exhibit A, Tab 1, Appendix A, Schedule 3.
(10) Actual 2017 deferral balance is expected to be included in the Application and Evidence for EB-2018-0105, but is draft at this time and may change.