EB-2016-0025

Ontario Energy Board

IN THE MATTER OF Application or approval to amalgamate to form LDC Co. and for LDC Co. to purchase and amalgamate with Hydro One Brampton Networks Inc.

VULNERABLE ENERGY CONSUMERS COALITION
(“VECC”)
CROSS-EXAMINATION COMPENDIUM

September 9, 2016

TAB 1

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

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.

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[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

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

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

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

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

Early Termination of Pre-Consolidation Rate-setting Term

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

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

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

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

Early Termination or Extension of Selected Deferred Rebasing Period

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

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

Rate Setting during Deferred Rebasing Period

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

Consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates. The 2015 Report clarified how rates will be set for a distributor who 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.

TAB 2

Ontario

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

DECISION AND RATE ORDER

EB-2015-0065

ENERSOURCE HYDRO MISSISSAUGA INC.

Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2016

BEFORE: Allison Duff
Presiding Member

Victoria Christie
Member

Cathy Spoel
Member

April 7, 2016

1 INTRODUCTION AND SUMMARY

Enersource Hydro Mississauga Inc. (Enersource) serves about 202,000 mostly residential and commercial electricity customers in the City of Mississauga. As a licenced and rate-regulated distributor in Ontario, the company must receive approval from the Ontario Energy Board (OEB) for the rates it charges to distribute electricity to its customers.

Enersource filed an application with the OEB seeking approval for changes to its distribution rates to be effective January 1, 2016. The application contained a request for new distribution rates based on the Price Cap incentive rate-setting (Price Cap IR) option, Renewable Energy Generation (REG) funding and an Incremental Capital Module (ICM). The OEB issued a Partial Decision and Order on March 3, 2016 and Interim Rate Order on March 17, 2016 which addressed the Price Cap IR and REG requests.

This is the OEB's Decision and Order with respect to Enersource's request for an ICM.

An ICM is a means by which a distributor can receive additional revenue from customers to fund capital expenditures in the years between cost of service applications. Enersource sought ICM funding for $68.3M, resulting in an additional 2016 revenue requirement of $5.3M to be recovered through rate riders effective January 1, 2016[1]. The ICM request included a payment to Hydro One Networks Inc. (Hydro One) and forecast 2016 capital expenditures.

After submissions from parties were filed, Enersource applied to the OEB for approval to defer its scheduled 2017 rebasing of distribution rates. The OEB approved Enersources's request. The deferral of Enersource's next cost of service application has affected the OEB's findings with respect to the ICM request. For the reasons outlined in this Decision, the OEB approves only ICM funding related to the Hydro One payment.

The total bill impact arising from this Decision for Enersource results in a monthly increase of $0.68 or 0.46% for a residential customer consuming 800 kWh. When combined with the previous partial decision and order issued on March 3, 2016, the bill impact is a monthly increase of $0.90 or 0.61%.

[1] As updated in EB-2015-0065, Undertaking JT1.17, January 18, 2016

3 INCREMENTAL CAPITAL MODULE

3.1 ICM Criteria

An ICM is available to distributors during the Price Cap IR years for capital investment needs that are additional to those approved through the last cost of service application.

Capital projects included in an ICM request must meet three criteria[2]:

- Materiality – each incremental capital project or expenditure must be material and clearly have a significant influence on the operation of the distributor
- Need – distributor must pass the Means Test; amounts must be based on discrete projects and directly related to the claimed driver, and must be clearly outside of the base upon which the rates were derived
- Prudence – amounts to be incurred must be prudent

In addition to the criterion that each project included in the ICM request be material, the total ICM request must exceed the ICM materiality threshold as described in section 3.5 below.

3.2 Project Materiality

Each capital project approved for ICM funding must be material to the distributor. Project materiality is 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million[3]. Enersource's last approved distribution revenue requirement was $118M[4] resulting in a project materiality of $590,000.

3.3 Need and The Means Test

As part of the "Need" criterion, the OEB applies the Means Test when reviewing ICM applications. The Means Test states that if a distributor's regulated return exceeds 300 basis points above the deemed regulatory return on equity (ROE) embedded in its rates, the funding for any incremental capital project will not be allowed. Enersource

[2] Filing Requirements for Electricity Distribution Rate Application, Chapter 3 Incentive Rate-Setting Applications, July 16, 2015, p. 17
[3] OEB's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, section 2.6
[4] EB-2012-0033

submitted evidence to show that its 2014 achieved regulatory ROE was 9.43% compared to the deemed ROE from the most recent cost of service application of 8.93%[5], a difference of 50 basis points.

3.4 Prudence

To be eligible for ICM funding, expenditures must be prudent, illustrating good judgement in the management of capital budgets. Enersource's ICM request includes the actual Hydro One payment and the forecast capital expenditures for 2016. While the Hydro One payment is for a past expenditure based on studies and planning exercises, the forecasted expenditures in the capital budget are based on asset condition assessments and a draft Distribution System Plan.

3.5 ICM Materiality Threshold

The OEB expects a distributor to fund its capital expenditures within the ICM materiality threshold, before being eligible to apply for ICM funding. The ICM materiality threshold is deducted from the total ICM request to determine the amount eligible to be recovered from customers.

The OEB defined the ICM materiality threshold in Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications[6] (the Filing Requirements). It represents a distributor's financial capacities underpinned by existing rates, including growth and a 20% dead band. The equation used to calculate the materiality threshold at the time of Enersource's application was as follows:

$$\text{Materiality Threshold Value} = 1 + (RB/d) * (g + PCI * (1 + g)) + 20\%$$

Where:
RB = rate base included in base rates ($)
d = depreciation expense included in base rates ($)
g = distribution revenue change from load growth (%)
PCI = price cap index

Enersource calculated its materiality threshold value to be 164%, which is multiplied by the last approved annual depreciation of $28.7M[7] to determine the ICM threshold of $47.2M.

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[5] Response to AMPCO-17, December 9, 2015
[6] Filing Requirements for Electricity Distribution Rate Application, Chapter 3 Incentive Rate-Setting Applications, July 16, 2015, p. 17
[7] EB-2012-0033

4 CAPITAL EXPENDITURES

Enersource forecast its 2016 capital expenditures to be $46.2M in its 2013 cost of service application.[8] Enersource updated its forecast for 2016 capital expenditures in this proceeding to $115.1M. The following table provides historical information and compares the 2016 capital expenditure forecasts.

Table 1 – Annual Capital Expenditures

$000	2012 Forecast	2012 Actual	2013 Forecast	2013 Actual	2014 Forecast	2014 Actual	2015 Forecast	2015 Updated Forecast	2016 Forecast	2016 Updated Forecast
System Service	9,312	9,860	11,134	10,712	10,329	11,228	10,507	16,267	10,686	19,226
System Renewal	14,483	16,225	16,326	20,887	18,329	31,257	19,319	35,204	20,939	34,961
System Access	10,675	11,493	5,525	10,055	5,968	9,474	5,293	14,633	5,268	7,451
General Plant	29,472	29,220	13,187	6,831	10,725	6,231	9,646	10,585	9,317	12,935
CAPITAL BUDGET	63,942	66,798	46,172	48,485	45,351	58,190	44,765	76,689	46,210	74,573
Hydro One TS payment										40,479
TOTAL CAPITAL EXPEDITURES										115,052

Source: Undertaking JT 1.2

Enersource's ICM funding request was $68.3M, equal to a 2016 total capital expenditure forecast of $115.4M (including Allowance for Funds Used During Construction) less the ICM materiality threshold of $47.2M.

The total capital expenditures of $115.4M, was the sum of two distinct components in the capital plan. The first was to recover the cost of a payment to Hydro One of $40.5 million relating to the construction of Churchill Meadows Transformer Station (Churchill Meadows TS). The second related to a 2016 forecast capital budget of $74.6M.

[8] EB-2012-0033, Exhibit 2, Tab 2, Schedule 2, Appendix 1, Table 17.6

4.1 Forecast Capital Expenditures Budget

In support of the 2016 forecast capital budget of $74.6M, Enersource referred to an Asset Condition Assessment Study (Asset Study) performed by a third party in 2014, information not available at the time of the last cost of service. Enersource developed upgrade, rebuild and renewal plans, based on the new asset age and condition information, which resulted in a higher capital expenditure forecast for 2016.

Enersource filed a copy of the Asset Study and a draft Distribution System Plan for 2016-2021[9] (DSP) in response to interrogatories. Enersource explained that the DSP was a draft because it did not reflect customer preferences[10] and that it would file a final DSP with its next cost of service application.

Findings

The OEB does not approve ICM funding for the 2016 forecast capital expenditures budget request as it does not meet the ICM criteria. The OEB does not have the context required to approve a 2016 capital expenditure budget that is 60% higher than the forecast from Enersource's last cost of service. The OEB will not decide the ICM funding request based on an Asset Study alone given the deferral of Enersource's 2017 cost of service application.

Chapter 5 of the Filing Requirements instructs distributors to file a DSP when filing a cost of service application for the rebasing of their rates and provides that the OEB may also require a DSP to be filed in relation to an ICM[11]. The OEB finds that the lack of a final DSP has impeded the assessment of the need and prudence for a request as sizable as Enersource's.

The OEB requires Enersource to file a final DSP before the OEB will consider ICM funding based on a 2016 forecast capital expenditures budget of $74.6M. The Asset Study shows that many upgrade, rebuild and renewal plans extend beyond 2016. A five-year DSP will enable the OEB to consider the longer-term implications of Enersource's capital plans.

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[9] Attachment to Interrogatory Supp-Staff-15, December 9, 2015
[10] EB-2015-0065, Supplementary ICM Evidence Summary, October 7, 2015, p.7
[11] Chapter 5:Consolidated Distribution System Plan Filing Requirements, March 28, 2013, p.7

TAB 3

B-EP-6

Reference(s): Exhibit B, Tab 5, Schedule 1

Preamble:

a) Please update Figure 20 to include data for 2015.

b) Will LDC Co continue to report SAIDI and SAIFI based on the four former LDC areas? If not, please explain how customers will be able to determine if their reliability metrics have improved or deteriorated?

c) The evidence indicates that the LDC Co column in Figure 21 is the arithmetic average of the four previous columns. Please add a column to Figure 21 that shows the SAIDI and SAIFI figures if they were calculated as if the four LDC's were only one LDC. Please confirm that this calculation would be more comparable to the future SAIDI and SAIFI figures for LDC Co in the future as compared the arithmetic average shown.

Response:

a) Please see the Applicants' response to Interrogatory B-AMPCO-11b).

b) LDC Co will report SAIDI and SAIFI as required by the Ontario Energy Board's ("OEB") *Electricity Reporting & Record Keeping Requirements* ("RRR").

Reporting SAIDI and SAIFI as a single, combined entity will not impact a customer's ability to determine if their specific reliability has improved or deteriorated. SAIDI and SAIFI are system averages and do not provide an indication of an individual customer's reliability. An individual customer's best indication of improving or declining reliability is the number of interruptions and outages they personally experience which is independent of whether SAIDI and SAIFI are reported based on the four former LDC areas or as a single, combined entity.

c) The Applicants have added a column "LDC Co Weighted Average" to Figure 21, in Table 1 below that shows the SAIDI and SAIFI figures if they were calculated as if the four LDCs were only one LDC. There are differences between the LDCs in terms of customer count, which is fundamental to the calculation of SAIDI and SAIFI. The additional Column, “LDC Co – Weighted Average”, which computes the SAIDI and SAIFI on a customer-based weighted average, is more appropriate and comparable to future SAIDI and SAIFI, as it factors in the customer count differences on an annual basis.

Table 1 – Figure 21 Adjusted - Five Year Average (SAIDI & SAIFI)

	2010 - 2014 Results					
Adjusted	Enersource	Horizon Utilities	PowerStream	HOBNI	LDC Co (Arithmetic Average)	LDC Co (Weighted Average*)
Loss of Supply Adjusted						
5 year Average SAIDI (in hours)	0.82	2.15	2.76	2.45	2.05	2.14
5 year Average SAIFI	1.30	1.71	1.45	1.41	1.47	1.48

B-VECC-3

Reference(s): B/T5/S1/Figure 5/pg. 5

Preamble:

a) With the exception of 2013 Enersource and HOBNI have significantly better SAIDI and SAIFI results than the other two Utilities over the 2010-2014 period. Please explain the reasons for this and what steps will be taken to ensure the superior service reliability in the Enersource and HOBNI service areas be maintained after consolidation.

b) Please update Figure 20 for 2015 data.

Response:

a) Enersource and HOBNI's SAIDI and SAIFI results, with the exception of 2013, are better than Horizon Utilities and PowerStream's SAIDI and SAIFI results due to a number of factors. As identified on page 6 of the Ontario Energy Board's ("OEB") *Report of the Board on Electricity Distribution System Reliability Measures and Expectations* (EB-2014-0189), dated August 25, 2015:

> *"In Ontario, distributors operate under many varying business conditions that have contributed to their current reliability performance, including their historical asset investment strategy, their design criteria, age of assets, the amount of underground assets mandated by the local authority, the mix of customers, population density and localized weather events, etc.".*

The circumstances described above apply to both Horizon Utilities and PowerStream. The Applicants are committed to reliability across the entire service area of LDC Co. Please see the Applicants' response to Interrogatory B-BOMA-6b).

b) Please see the Applicants' response to Interrogatory B-AMPCO-11b).

B-AMPCO-11

Reference(s): Exhibit B, Tab 5, Schedule 1, Page 5, Figure 20

Preamble:

a) For each year for SAIDI and SAIFI, please add the following adjustments to the Figure: Major Event Days Adjusted, Scheduled Outages Adjusted.

b) Please add the reliability data for 2015 to the table in part (a).

Response:

a) In Table 1 below, the Applicants provide the following adjustments to Figure 20 for each year of SAIFI and SAIFI: Major Event Days Adjusted, Scheduled Outages Adjusted.

With respect to the Major Event Days Adjusted calculation, the Applicants have adopted the Institute of Electrical and Electronics Engineers ("IEEE") 1366 Standard definition of a Major Event Day ("MED"). A MED is any day that exceeds a daily SAIDI threshold as determined using historical data. HOBNI's definition of a MED for 2010-2015 was based on sustained outages caused by severe weather storm conditions. HOBNI's classification of outages related to major storms was based on the parameters used by Environment Canada for the identification of major storms and severe weather related to the City of Brampton.

Table 1: Reliability Metrics of the Parties for 2010-2014

	2014			
	Enersource	Horizon Utilities	PowerStream	HOBNI
SAIDI	0.67	2.18	1.45	0.57
SAIDI Loss of Supply Adjusted	0.67	1.59	1.39	0.55
SAIDI Major Event Days Adjusted	0.53	1.05	1.23	0.57
SAIDI Scheduled Outages Adjusted	0.59	2.07	1.31	0.55
SAIFI	1.13	1.91	1.71	0.95
SAIFI Loss of Supply Adjusted	1.13	1.65	1.64	0.90
SAIFI Major Event Days Adjusted	0.97	1.34	1.48	0.95
SAIFI Scheduled Outages Adjusted	1.11	1.64	1.66	0.95

	2013			
	Enersource	Horizon Utilities	PowerStream	HOBNI
SAIDI	5.34	4.97	10.68	10.46
SAIDI Loss of Supply Adjusted	1.49	4.36	9.77	9.84
SAIDI Major Event Days Adjusted	0.60	1.01	1.21	1.12
SAIDI Scheduled Outages Adjusted	5.26	4.87	10.55	10.43
SAIFI	2.72	2.09	2.54	3.64
SAIFI Loss of Supply Adjusted	1.37	1.76	2.24	3.30
SAIFI Major Event Days Adjusted	1.41	1.24	1.37	1.26
SAIFI Scheduled Outages Adjusted	2.67	1.84	2.50	3.62

	2012			
	Enersource	Horizon Utilities	PowerStream	HOBNI
SAIDI	0.70	1.45	1.16	0.76
SAIDI Loss of Supply Adjusted	0.68	1.43	1.04	0.74
SAIDI Major Event Days Adjusted	0.70	1.13	1.16	0.76
SAIDI Scheduled Outages Adjusted	0.66	1.35	1.08	0.74
SAIFI	1.71	1.95	1.70	1.27
SAIFI Loss of Supply Adjusted	1.36	1.83	1.53	1.06
SAIFI Major Event Days Adjusted	1.71	1.49	1.70	1.27
SAIFI Scheduled Outages Adjusted	1.71	1.56	1.66	1.26

	2011			
	Enersource	Horizon Utilities	PowerStream	HOBNI
SAIDI	0.89	2.25	1.20	0.73
SAIDI Loss of Supply Adjusted	0.72	2.23	1.05	0.68
SAIDI Major Event Days Adjusted	0.89	1.01	1.06	0.73
SAIDI Scheduled Outages Adjusted	0.83	2.18	1.13	0.71
SAIFI	1.97	1.74	1.23	1.19
SAIFI Loss of Supply Adjusted	1.54	1.74	1.00	1.05
SAIFI Major Event Days Adjusted	1.97	1.42	1.13	1.19
SAIFI Scheduled Outages Adjusted	1.96	1.67	1.19	1.18

	2010			
	Enersource	Horizon Utilities	PowerStream	HOBNI
SAIDI	0.58	1.24	0.81	0.66
SAIDI Loss of Supply Adjusted	0.55	1.15	0.54	0.46
SAIDI Major Event Days Adjusted	0.59	0.90	0.64	0.66
SAIDI Scheduled Outages Adjusted	0.42	1.14	0.76	0.64
SAIFI	1.32	1.80	0.92	1.47
SAIFI Loss of Supply Adjusted	1.10	1.55	0.80	0.76
SAIFI Major Event Days Adjusted	1.32	1.71	0.91	1.47
SAIFI Scheduled Outages Adjusted	1.21	1.74	0.90	1.46

b) The Applicants provide the reliability data for 2015 in Table 2 below.

Table 2: Reliability Metrics of the Parties for 2015

	2015			
	Enersource	**Horizon Utilities**	**PowerStream**	**HOBNI**
SAIDI	0.72	1.77	1.99	0.72
SAIDI Loss of Supply Adjusted	0.64	1.69	1.93	0.68
SAIDI Major Event Days Adjusted	0.72	1.43	1.19	0.48
SAIDI Scheduled Outages Adjusted	0.60	1.66	1.87	0.68
SAIFI	1.64	1.92	1.52	1.22
SAIFI Loss of Supply Adjusted	1.46	1.58	1.42	0.89
SAIFI Major Event Days Adjusted	1.64	1.65	1.14	1.08
SAIFI Scheduled Outages Adjusted	1.60	1.67	1.48	1.20

TAB 4

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

DECISION AND ORDER

EB-2015-0003

POWERSTREAM INC.

Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020

BEFORE: Ken Quesnelle
Vice Chair and Presiding Member

Ellen Fry
Member

August 4, 2016

> The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.
>
> The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.[8]

Accordingly, PowerStream needs to rethink the approach in its application to assessing productivity improvement. It would not be appropriate for the OEB to direct a solution to remedy this basic deficiency. PowerStream should consider how best to achieve this in its next rebasing rate setting application.

Capital Investment

In the absence of internal benchmarking to confirm and measure continuous improvement, the OEB has conducted a detailed review of PowerStream's spending plans. The OEB does not consider that PowerStream has provided sufficient evidence of what its capital investment will accomplish in terms of outcomes for customers, and why they are appropriate, to justify approving its capital investment beyond 2017. Although the case record of this proceeding contains a large volume of evidence, it does not contain sufficient evidence on this issue.

Customer Engagement

PowerStream has provided evidence that its Distribution System Plan was substantially complete when it engaged Innovative Research Group Inc. to perform engagement activities with its customers. PowerStream's evidence is that it was squeezed for time to

[8] EB-2013-0416/EB-2014-0247 *Decision,* March 12, 2015, p. 14

REBASING DEFERRAL PERIOD

The Applicants have chosen to defer the rebasing for LDC Co for ten years from the date of closing of the last of the proposed transactions, consistent with the Consolidation Policy and the Handbook. Accordingly:

(a) the Enersource and HOBNI rate zones would maintain Price Cap Incentive Regulation ("IR") until the end of the ten year rebasing deferral period;

(b) the Horizon Utilities rate zone would remain on Custom IR until 2019 and after that would maintain Price Cap IR until the end of the ten year rebasing deferral period;

(c) the PowerStream rate zone would remain on Custom IR until 2020, assuming approval of the PowerStream application for a 2016-2020 Custom IR term pending before the Board, and beyond that term the PowerStream rate zone would maintain Price Cap IR until the end of the ten year rebasing deferral period; and

(d) During the rebasing deferral period, LDC Co may apply for rate adjustments using the Board's ICM as may be necessary and in accordance with applicable Board policies with respect to eligibility for, and the use of, the ICM.

B-STAFF-28

Reference(s): Exh B/T6/ Sch 3, p. 1

Preamble:

It is stated that "The assumption for future rate levels in the valuation was based on annual rebasing for the Applicants going forward from the time of the next rebasing application."

a) Please elaborate on the above specifically discussing why annual rebasing was assumed from the time of the next rebasing and what impact this assumption had on the valuation as compared to an assumption that rebasing would occur only every five years.

b) Please state the plan for all applications for rate changes from the merged entity or its rate zones which are presently anticipated in the period until 2025. Please include in this plan when the applicants propose seeking approval for certain rate-setting issues such as:

i. The earnings sharing mechanism for the Horizon rate zone

ii. The stretch factor to be used for the zones on the Price Cap IR

iii. The ROE to be used for earnings sharing of the consolidated entity

iv. Any rate riders that are expected to end during the term

Response:

a) Please see the Applicants' response to Interrogatory B-Staff-22a).

b) Figure 1 below provides the plan for anticipated applications for rate changes for the rate zones over the period to 2025, and including 2026 (tenth year of the rebasing deferral period).

Figure 1 – Rate Setting During the Ten Year Rebasing Deferral Period

	1	2	3	4	5	6	7	8	9	10
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Enersource	IRM with potential for ICM									
Horizon Utilities	Custom IR (Annual Filing)			IRM with potential for ICM						
PowerStream	Custom IR (Annual Filing)*				IRM with potential for ICM					
HOBNI	IRM with potential for ICM									

B-CCC-14

Reference(s): B/T2/S1/p. 9

Preamble:

The Applicants have confirmed that they have chosen to defer LDC Co's rebasing from the date of the closing the last of the proposed transactions. What specific relief are the Applicants seeking with respect to this proposal? Under what circumstances could this change and the Applicants seek an earlier rebasing?

Response:

a) The Applicants have identified that they will defer LDC Co's rebasing for ten years from the date of closing the last of the proposed transactions, as identified on page 9 of Exhibit B, Tab 2, Schedule 1. There are no circumstances contemplated currently under which this could change. The ten year rebasing deferral period is consistent with the Ontario Energy Board's March 26, 2015 *Report on Rate-Making Associated with Distributor Consolidation* (the "Consolidation Policy") and with the *Handbook to Electricity Distributor and Transmitter Consolidations*.

TAB 5

B-AMPCO-9

Reference(s): Exhibit B, Tab 6, Schedule 1, Page 4, Figure 26

Preamble:

a) Please explain the decrease in distribution revenue in 2026.

b) Please explain the increase in distribution revenue in 2027.

c) Please explain the forecast increases in distribution revenue beyond 2027 (2028 to 2039).

d) Please provide all assumptions regarding an ICM in Figure 26.

e) Please provide the forecast revenue by year to be collected from any ICM recovery rate riders.

f) Please recast Figure 26 without an ICM.

Response:

a) The decrease in distribution revenue in 2026 is the result of the first rebasing following the ten year rebasing deferral period. The rebasing results in a forecast revenue requirement reduction of $69.3MM. On rebasing, the operating and capital synergies will be included in the calculation of the rate base and be incorporated into customers' rates.

b) The Applicants expect and assume that LDC Co will file successive Custom IR applications commencing in year eleven post-consolidation. Distribution rates are forecast to recover prudently incurred costs.

c) Please see b) above.

d) The ICM Assumptions are:
- Average customer growth factors: PowerStream: - 1.7%; Enersource: – 0.6%; Horizon Utilities: – 0.7%; Hydro One Brampton: – 1.3%;
- Price Cap Index increases: PowerStream and Horizon utilities: 1.30%; Enersource: 1.45%; HOBNI: 1.4%; and

ATTACH3-STAFF-30

Reference(s): Attachment 3/Summary of the Financing Plan

Preamble:

The evidence indicates that a key assumption of the plan is that "Holdco may file for ICM in each year".

a) Please provide the current estimate of the total incremental capital to be sought via ICM until rebasing.

b) Please provide details on what ICM amounts, if any, are reflected in the revenue and net income projections in Attachment 2.

c) Please confirm that any ICM would only be for those rate zones that will be on the Price Cap IR rate-setting.

Response:

a) The Applicants estimate that the total incremental capital to be sought via ICM until rebasing is $414MM.

b) The ICM amounts in Attachment 2 include approximately $130MM for the revenue projection and $107MM for the net income projection.

c) The Applicants note that ICM is available for distributors on the Price Cap IR rate-setting framework. The Applicants confirm that they expect to make use of that option for the rate zones, as applicable. Please also see the Applicants' response to Interrogatory B-Staff-29.

B-AMPCO-9

Reference(s): Exhibit B, Tab 6, Schedule 1, Page 4, Figure 26

Preamble:

a) Please explain the decrease in distribution revenue in 2026.

b) Please explain the increase in distribution revenue in 2027.

c) Please explain the forecast increases in distribution revenue beyond 2027 (2028 to 2039).

d) Please provide all assumptions regarding an ICM in Figure 26.

e) Please provide the forecast revenue by year to be collected from any ICM recovery rate riders.

f) Please recast Figure 26 without an ICM.

Response:

a) The decrease in distribution revenue in 2026 is the result of the first rebasing following the ten year rebasing deferral period. The rebasing results in a forecast revenue requirement reduction of $69.3MM. On rebasing, the operating and capital synergies will be included in the calculation of the rate base and be incorporated into customers' rates.

b) The Applicants expect and assume that LDC Co will file successive Custom IR applications commencing in year eleven post-consolidation. Distribution rates are forecast to recover prudently incurred costs.

c) Please see b) above.

d) The ICM Assumptions are:

- Average customer growth factors: PowerStream: - 1.7%; Enersource: – 0.6%; Horizon Utilities: – 0.7%; Hydro One Brampton: – 1.3%;
- Price Cap Index increases: PowerStream and Horizon utilities: 1.30%; Enersource: 1.45%; HOBNI: 1.4%; and

- Deadband of 20.0%.

e) The forecast revenue by year to be collected via ICM recovery rate riders is identified in Table 1 below.

Table 1 - Incremental ICM Revenue

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental ICM Revenue ($MM)	3.7	6.1	7.3	8.9	10.3	12.7	16.0	19.3	21.9	24.3

The aggregate ICM revenue is $130MM.

VT INCEPIT FIDELIS SIC PERMANET
Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2016-0025**	**Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc.**

VOLUME:	**Technical Conference**
DATE:	**August 24, 2016**

will --

MR. GARNER: If it's available. I take your proviso.

MS. BUTANY-DESOUZA: -- undertake to provide it.

MS. HELT: Okay. So Undertaking JTC1.12 will be to provide the most recent Appendix 2A and B that have been filed with the Board --

MS. BUTANY-DESOUZA: Sorry, 2AB.

MS. HELT: 2AB, yes, for Horizon, PowerStream, and Hydro One Brampton, and then to look for what you may have of a similar nature for Enersource which shows what there is on a projection basis.

MR. GARNER: Yeah, on a capital forecast basis that was filed in front of the Board in the last application.

MS. HELT: Okay. So that is JTC1.12.

UNDERTAKING NO. JTC1.12: TO PROVIDE THE MOST RECENT APPENDIX 2AB THAT HAS BEEN FILED WITH THE BOARD FOR HORIZON, POWERSTREAM, AND HYDRO ONE BRAMPTON, AND THEN TO LOOK FOR WHAT YOU MAY HAVE OF A SIMILAR NATURE FOR ENERSOURCE WHICH SHOWS WHAT THERE IS ON A PROJECTION BASIS.

MR. GARNER: Thank you. Now the reason I am asking is I am trying to understand in my own mind how the ICM forecast, first of all, that you have done arises based on the last projections that each one of those utilities has put forward.

So notwithstanding HOBNI, for instance, rate plan is, let's say, price cap, it did provide a projection and presumably filed its application at that time based on its understanding of what its capital program was going to be.

What I am trying to figure out is since that time, it seems to me that what has arisen in this application is a new projection of unforecasted capital plans. Am I wrong?

MS. BUTANY-DESOUZA: You're -- with respect, that's not the case. So for -- if we can use the Horizon Utilities and PowerStream rate zones as examples, the projection on ICM, across the four utilities in fact, is based on eligibility for ICM.

So the Board's policy provides that if you are on a custom IR, then you are not eligible for ICM until your custom IR terminates.

MR. GARNER: Hmm-hmm.

MS. BUTANY-DESOUZA: So there's no ICM built into the model and included in our numbers for 20 -- well, we show 2016 through 2019, and that's exactly the five years of the Horizon Utilities custom IR term. So it is not a change in that capex projection.

The DSP and, in fact, 2AB that we would have filed in EB-2014-0002, that custom IR application, they would have included that capital projection for just that five-year period.

The incremental capital that is related in this application -- for instance, for the Horizon Utilities rate zone -- is beyond 2019. So the custom IR term ends. Horizon shifts on to price cap per the Board's MAADs consolidation guidelines, and it is within that second path of the period -- so from 2020 through to 2025, or the

Undertaking No. JTC1.13

Reference: Page 123 of Transcripts Volume 1

Review the response to B-SEC-18. Correct the response and table in B-SEC-18 as necessary to identify only capital which is incremental to previously Board-approved capital expenditures. Confirm if the ICM requests depart from previously Board-approved capital expenditures.

Response:

Please see Table 1 below which includes an added column for totals and some clarifying formatting and labeling changes. There is no need for changes to the dollar amount entries relative to the table provided in response to Interrogatory B-SEC-18e), as the original table is correct. By definition, "Incremental Capital" and "Net Incremental Capital" are incremental to Board-approved capital expenditures.

Table 1 - Revision to Table B-SEC-18e)

Total Incremental Capital ($MM)												
Enersource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total 2015-2025**
Incremental Capital	55.4	24.6	17.3	13.6	16.6	16.6	23.2	24.6	26.1	27.5	29.2	274.5
Depreciation	1.4	0.6	0.4	0.3	0.4	0.4	0.6	0.6	0.7	0.7	0.4	6.5
Net Incremental Capital	54.0	24.0	16.9	13.3	16.2	16.2	22.6	24.0	25.4	26.8	28.8	268.0
ICM Revenue - Included in I/S - 1 Year Lag	-	3.7	5.4	6.5	7.4	8.6	9.7	10.8	12.1	13.4	14.8	92.3
PowerStream	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total 2015-2025**
Incremental Capital	45.0	40.5	23.4	4.7	9.1	0.7	22.3	21.6	-	-	5.0	172.2
Depreciation	1.1	1.0	0.6	0.1	0.2	0.0	0.6	0.5	-	-	0.1	4.2
Net Incremental Capital	43.9	39.5	22.8	4.6	8.9	0.7	21.8	21.0	-	-	4.9	168.0
ICM Revenue - Included in I/S - 1 Year Lag	-	-	-	-	-	-	-	1.0	2.0	2.0	2.0	7.2
Hydro One Brampton	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total 2015-2025**
Incremental Capital	4.0	10.9	-	9.5	4.3	4.2	7.8	8.5	9.2	9.9	10.8	79.1
Depreciation	0.1	0.3	-	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.1	1.8
Net Incremental Capital	3.9	10.6	-	9.3	4.2	4.1	7.6	8.3	9.0	9.7	10.7	77.2
ICM Revenue - Included in I/S - 1 Year Lag	-	-	0.8	0.8	1.5	1.8	2.1	2.5	2.9	3.4	4.0	19.7
Horizon Utilities	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total 2015-2025**
Incremental Capital	1.5	0.3	1.5	0.4	2.0	15.7	14.8	13.5	16.2	11.1	17.2	94.3
Depreciation	0.0	0.0	0.0	0.0	0.1	0.4	0.4	0.3	0.4	0.3	0.2	2.1
Net Incremental Capital	1.5	0.3	1.5	0.4	2.0	15.3	14.4	13.2	15.8	10.8	17.0	92.1
ICM Revenue - Included in I/S - 1 Year Lag	-	-	-	-	-	-	1.0	1.6	2.3	3.0	3.5	11.4
Total	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total 2015-2025**
Total Incremental Capital	**103.2**	**74.4**	**41.2**	**27.6**	**31.2**	**36.2**	**66.3**	**66.5**	**50.2**	**47.3**	**61.4**	**605.4**
Total Net Incremental Eligible Capital	**54.0**	**34.6**	**16.9**	**22.6**	**20.3**	**35.5**	**66.3**	**66.5**	**50.2**	**47.3**	**-**	**414.2**
Total Forecast ICM Revenue	**-**	**3.7**	**6.1**	**7.3**	**8.9**	**10.3**	**12.7**	**16.0**	**19.3**	**21.9**	**24.3**	**130.6**

ATTACH 2-VECC-8

Reference(s): Attachment 2/pg.3; Attachment 3/pg.5

Preamble:

a) Post consolidation will the combined rate base of the new utility be used for the purpose of calculating any ICM materiality threshold? If not please explain.

Response:

a) Matters related to the ICM materiality threshold for future ICM applications will be addressed in future ICM applications.

TAB 6

Undertaking No. JTC1.12

Reference: Page 116 of Transcripts Volume 1

Provide the most recent and approved Appendix 2-AB for each of Horizon Utilities, Hydro One Brampton and PowerStream. Provide a similar schedule for Enersource which identifies future capital expenditures and was filed with the last rebasing application, if available.

Response:

The Applicants have provided the most recent Appendix 2-AB for each of Horizon Utilities, HOBNI, and PowerStream in Tables 1 to 3, below. A similar schedule for Enersource, that was filed as part of the Fourth Generation Incentive Rate-setting ("Price Cap IRM and ICM") application (EB-2015-0065) is provided in Table 4, below.

Table 1: Horizon Utilities Appendix 2-AB (EB-2014-0002)

CATEGORY	Historical Period						Forecast Period (planned)				
	2010 (CGAAP)	2011 (CGAPP)	2011 (MIFRS)	2012 (MIFRS)	2013 (MIFRS)	2014 (MIFRS)	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Actual	Plan					
	$ '000						$ '000				
System Access	13,558	8,914	5,629	6,602	6,369	7,540	8,063	8,040	7,464	7,660	7,841
System Renewal	14,082	22,475	17,171	14,091	18,425	14,872	16,450	26,926	31,800	33,040	34,538
System Service	3,583	3,125	2,374	2,885	2,151	4,101	4,140	295	535	2,032	2,057
General Plant	6,208	4,584	4,584	8,748	12,559	10,760	9,487	5,887	5,827	4,411	5,036
TOTAL EXPENDITURE BEFORE SMART METERS	**37,432**	**39,098**	**29,758**	**32,326**	**39,505**	**37,273**	**38,140**	**41,148**	**45,626**	**47,143**	**49,472**
Smart Meter Implementation				23,278			-				
TOTAL EXPENDITURE INLCUDING SMART METERS	**37,432**	**39,098**	**29,758**	**55,604**	**39,505**	**37,273**	**38,140**	**41,148**	**45,626**	**47,143**	**49,472**
Hydro One Contribution	-	-	-	10,000	-	-	-				
TOTAL EXPENDITURES	**37,432**	**39,098**	**29,758**	**65,604**	**39,505**	**37,273**	**38,140**	**41,148**	**45,626**	**47,143**	**49,472**
Change in WIP	- 2,841	743	743	4,654	- 1,597	2,019	175				
TOTAL ADDITIONS	**34,590**	**39,841**	**30,501**	**70,258**	**37,908**	**39,292**	**38,315**	**41,148**	**45,626**	**47,143**	**49,472**

Horizon Utilities Custom IR EB-2014-0002, Appendix 2-AB

Table 2: HOBNI Appendix 2-AB (EB-2014-0083)

CATEGORY							Forecast Period (planned)				
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Actual	Bridge Year	As Settled				
	$ '000						$ '000				
System Access	26,058	22,210	11,601	15,198	11,970	18,399	17,759	14,999	14,445	14,878	15,081
System Renewal	4,090	7,289	7,169	8,694	12,123	9,073	8,880	9,311	10,330	10,121	9,007
System Service	1,135	1,843	942	1,439	1,475	715	1,485	600	530	624	677
General Plant	2,010	4,387	4,365	2,181	4,505	3,697	9,741	9,289	3,966	3,982	3,741
Total Expenditure	**33,294**	**35,730**	**24,077**	**27,512**	**30,073**	**31,885**	**37,865**	**34,197**	**29,271**	**29,605**	**28,505**

Hydro One Brampton Networks Inc. Cost of Service Rate Application EB-2014-0083 Ex. 2, Tab 5, Schedule 1 and Settlement Proposal filed October 9, 2014, page 16

Table 3: PowerStream Appendix 2-AB (EB-2015-0003)

CATEGORY	Historical Period					Proposed				
	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Plan	2016	2017	2018	2019	2020
	$ '000					$ '000				
System Access	21,007	19,888	17,030	26,229	24,145	28,232	28,470	29,561	28,726	31,867
System Renewal	11,527	16,974	22,254	39,186	42,388	48,715	51,500	52,052	52,971	52,406
System Service	22,885	13,770	34,780	17,946	27,322	38,322	32,072	29,920	26,963	23,022
General Plant	7,877	24,200	19,593	26,148	24,545	17,531	19,458	13,867	16,741	18,106
Sub-Total	**63,296**	**74,832**	**93,657**	**109,509**	**118,400**	**132,800**	**131,500**	**125,400**	**125,401**	**125,401**
Non-Rate Base	2,278	1,196	2,628	1,364	2,489					
Grand Total	**65,574**	**76,028**	**96,285**	**110,873**	**120,889**	**132,800**	**131,500**	**125,400**	**125,401**	**125,401**

PowerStream Inc. Custom IR EB-2015-0003, Ex. G, Tab 2, Page 3

Table 4: Enersource Historical and Forecasted Capital Expenditures (gross capex values) (EB-2015-0065)

CATEGORY	Historical Period					Proposed					
	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016	2017	2018	2019	2020	2021
	$ '000					$ '000					
System Access	11,858	9,860	10,712	11,228	16,497	17,200	13,015	13,130	12,825	13,105	13,490
System Renewal	11,422	16,224	20,887	31,257	36,058	34,735	37,243	38,240	40,280	38,570	38,490
System Service	14,326	11,493	10,055	9,474	16,452	12,408	17,916	18,123	18,162	17,238	10,568
General Plant	9,052	29,220	6,831	6,230	10,682	12,796	11,337	10,281	10,794	10,755	9,984
Sub-Total	**46,658**	**66,797**	**48,485**	**58,189**	**79,689**	**77,139**	**79,511**	**79,774**	**82,061**	**79,668**	**72,532**
Churchill Meadows CCRA Payment					40,479						
TOTAL EXPENDITURES	**46,658**	**66,797**	**48,485**	**58,189**	**120,168**	**77,139**	**79,511**	**79,774**	**82,061**	**79,668**	**72,532**

Enersource Hydro Mississauga Inc. Price Cap IRM and ICM Application EB-2015-0065, Interrogatory Response Supp-Staff-15, page 167

"Total Net Incremental Eligible Capital" is the total amount that is both incremental to Board-approved capital expenditures pursuant to each distributor's last rebasing application, as well as being eligible for ICM treatment due to coinciding with an IRM year.

EB-2014-0002

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

AND IN THE MATTER OF an application by Horizon Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through to December 31, 2019.

SETTLEMENT PROPOSAL

FILED SEPTEMBER 22, 2014

improve its reliability and service quality with impacts on rates that will not require mitigation measures. The Parties agree that the proposed capital and OM&A expenditures are appropriately balanced, and that the agreed-upon revenue requirement (reflecting reductions to both capital expenditures and OM&A as they were proposed in the Application) are expected to permit Horizon Utilities to meet its regulatory obligations; operate and maintain its distribution system; and maintain its financial viability.

The revised capital budget is as follows:

Settlement Table 15 - 2015 Capital Expenditure Plan

Capital Expenditures	Application	Interrogatory Updates	Variance: Application vs. Interrogatory Updates	Settlement	Variance: Application vs. Settlement
System Access	$8,242,598	$8,242,598	$0	$8,062,598	($180,000)
System Renewal	$18,070,415	$18,070,415	$0	$16,450,415	($1,620,000)
System Service	$4,139,747	$4,139,747	$0	$4,139,747	$0
General Plant	$9,487,208	$9,487,208	$0	$9,487,208	$0
Total	$39,939,967	$39,939,967	$0	$38,139,967	($1,800,000)

Settlement Table 16 - 2016 Capital Expenditure Plan

Capital Expenditures	Application	Interrogatory Updates	Variance: Application vs. Interrogatory Updates	Settlement	Variance: Application vs. Settlement
System Access	$8,471,952	$8,471,952	$0	$8,039,952	($432,000)
System Renewal	$28,293,649	$28,293,649	$0	$26,925,649	($1,368,000)
System Service	$294,732	$294,732	$0	$294,732	$0
General Plant	$5,887,200	$5,887,200	$0	$5,887,200	$0
Total	$42,947,533	$42,947,533	$0	$41,147,533	($1,800,000)

Settlement Table 17 - 2017 Capital Expenditure Plan

	Application	Interrogatory Updates	Variance: Application vs. Interrogatory Updates	Settlement	Variance: Application vs. Settlement
System Access	$7,896,202	$7,896,202	$0	$7,464,202	($432,000)
System Renewal	$33,167,877	$33,167,877	$0	$31,799,877	($1,368,000)
System Service	$535,135	$535,135	$0	$535,135	$0
General Plant	$5,826,900	$5,826,900	$0	$5,826,900	$0
Total	$47,426,114	$47,426,114	$0	$45,626,114	($1,800,000)

Settlement Table 18 - 2018 Capital Expenditure Plan

	Application	Interrogatory Updates	Variance: Application vs. Interrogatory Updates	Settlement	Variance: Application vs. Settlement
System Access	$8,091,602	$8,091,602	$0	$7,659,602	($432,000)
System Renewal	$33,208,155	$33,208,155	$0	$33,040,155	($168,000)
System Service	$2,031,847	$2,031,847	$0	$2,031,847	$0
General Plant	$5,610,900	$5,610,900	$0	$4,410,900	($1,200,000)
Total	$48,942,504	$48,942,504	$0	$47,142,504	($1,800,000)

Settlement Table 19 - 2019 Capital Expenditure Plan

	Application	Interrogatory Updates	Variance: Application vs. Interrogatory Updates	Settlement	Variance: Application vs. Settlement
System Access	$8,273,338	$8,273,338	$0	$7,841,338	($432,000)
System Renewal	$34,706,031	$34,706,031	$0	$34,538,031	($168,000)
System Service	$2,057,209	$2,057,209	$0	$2,057,209	$0
General Plant	$6,235,900	$6,235,900	$0	$5,035,900	($1,200,000)
Total	$51,272,477	$51,272,477	$0	$49,472,477	($1,800,000)

3.3 Is the proposal to leave stranded meters in rate base appropriate?

Status: **Complete Settlement**

Supporting Parties: AMPCO, BOMA, Hamilton, CCC, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 5, Schedule 1 – Stranded Meters

Interrogatories: 2-Staff-22; 2-EP-15; 2.0-VECC-7; 2-SIA-10

Technical Conference Questions: 2-Staff-57TC; 2-EP-69TC; 2-EP-70TC; 2.0-VECC-69TC

The installation of Smart Meters in Horizon Utilities' service area, pursuant to Ministerial and Board directions, resulted in the stranding of the conventional meters that were replaced by smart meters. Horizon Utilities had proposed in its Application to keep its stranded meters in rate base until they were fully depreciated. The Parties agree for the purposes of settlement that Horizon Utilities will remove the stranded meters from rate base and that Horizon Utilities will recover the net book value of the stranded meters, together with a return on those assets equal to the Board's short term debt rate as set out in its Cost of Capital Parameters for each of 2015, 2016 and 2017. These amounts will be tracked in deferral account 1555 Sub-account Stranded Meter Costs upon approval of the final rate order, consistent with the procedure set out at page 28 of the Board's Guideline *G-2011-0001 – Smart Meter Funding and Cost Recovery – Final Disposition*, issued December 15, 2011.

TAB 7

Undertaking No. JTCx1.17

Reference: Page 162 of Transcripts Volume 1

Use best efforts to provide the most current organizational chart for the management structure of LDC Co. The chart is not to provide names, but rather positions of the managements structure of the utility.

Response:

The [redacted] executive positions reporting directly to the CEO and Presidents have been approved and the organizational chart provided as attachment "JTCx1.17 Attachment_Draft Executive Organizational Structure". The management structure below this level is currently under review and will be finalized following the appointment of these executive positions.

JTCx1.17_ATTACHMENT DRAFT EXECUTIVE ORGANIZATIONAL STRUCTURE

MergeCo

[redacted]

[redacted]

CAA-SEC-41

Reference(s): Corporation Amalgamation Agreement, p. 6

Preamble:

a) Please provide a list of the expected directors and officers of the Amalgamated Corporation after the Closing Date.

Response:

a) The officers and directors of the Amalgamated Corporation (LDC Co.) have not yet been determined, save and except for:

- Brian Bentz, President and CEO (designate), Holdco
- Max Cananzi, President (designate), LDC Co
- Peter Gregg, President (designate), Innovation, Growth and Corporate Services

ATTACH2-STAFF-20

Reference(s):

Attachment 2, p. 9

Preamble:

Please explain the causes/assumptions that are the basis for the $19.5M, or 3.3% reduction in revenues relative to status quo in the first ten years of the consolidation.

Response:

The Applicants observe that the question refers to page 8 of Attachment 2.

The reduction in distribution revenues in the first ten years relative to the *status quo* is due to the fact that after the consolidation LDC Co would not be rebasing before the end of the deferral period, while in the *status quo* scenario the Parties would be submitting Custom IR applications during that time. For example, while in the *status quo* scenario, Horizon Utilities would submit a Custom IR application in 2020 and PowerStream in 2021. After the consolidation, both of those rate zones will move to Price Cap IR after the expiry of their current rate regimes, resulting in lower distribution rates for the customers in those two rate zones. Similarly, Enersource and Hydro One Brampton will stay on Price Cap IR after the merger, while in the *status quo* scenario those parties would have rebased in 2017 and 2020, respectively.