**EP-1**

**References: Exhibit 1, Tab 3, Schedule 1, Page 5, Figure 2: Long-Term System Renewal Trends; Exhibit 2, Tab 1, Schedule 2, Page 1**

**Preamble: "While the predecessor capital plans were appropriate for those utilities, the DSP is based on the needs of the entire Alectra Utilities distribution system, and its operation as a single utility. The DSP supports the effective and efficient planning of capital expenditures across Alectra Utilities' entire service area. As such, the DSP is not based on historical capital budgets of the predecessor utilities, rather it was developed from identified investment needs using a common and uniform Asset Management Framework."**

**Question:**

a) **Clarify if the approvals sought are for the DSP (green line) or Partial Funding (purple line).**

b) **Indicate the annual and total differences in capital for DSP and PF scenarios for the period 2019-2024.**

c) **Please provide a version of Figure 2 showing in bar chart form, the ACA- based capital requirement by former utility and post-merger rate zone from 2019-2024 (as applicable). Please add percentages.**

d) **Please also provide a Table that shows the ACA capital breakdowns corresponding to the chart.**

e) **Please insert a table row showing the approved annual and total Capital Plan from each of the approved DSPs prior to merger, add a row that shows actual capital spend in each of the years and provide explanatory notes and references.**

f) **Please explain in detail the basis of the "surge" in Alectra Capital starting in 2027/28.**

**Response:**

a) Alectra Utilities is seeking capital funding based on a rate-adjustment mechanism, referred to as an “M-Factor”, which reconciles the capital needs set out in Alectra Utilities’ Distribution System Plan (“DSP”), which has been prepared on a consolidated basis for its entire service territory and included in this Application, with the capital-related revenue in rates.

The green line in Figure 2 presented on page 5 of the DSP (Exhibit 1, tab 3, Schedule 1, Page 5, Figure 2) represents the planned capital investments that make up a portion of the capital renewal needs outlined in the DSP.

b) Alectra Utilities provides the annual and total difference between the scenario of planned renewal investments proposed in Figure 2 from the scenario of partial funding in Table 1, below.

**Table 1 - Cost Differences between DSP Proposed and Partial Funding Scenarios**

| Year | Difference Between DSP Proposed and Partial Funding Scenarios ($MM) |
|---|---|
| 2019 | - |
| 2020 | 10.98 |
| 2021 | 28.42 |
| 2022 | 34.77 |
| 2023 | 41.64 |
| 2024 | 48.85 |
| **Total** | **164.66** |

c) The model used to create the scenarios, shown in Exhibit 1, Tab 3, Schedule 1, Page 5, Figure 2, leverages the combined demographic data for Alectra Utilities as a single entity. It is not feasible to break the analysis by predecessor utilities.

d) Alectra Utilities provides Table 2, below which provides capital values associated with Figure 2 as provided in Exhibit 1, Tab 3, Schedule 1, Page 5.

**Table 2 - ACA Capital Breakdowns**

| Year | Condition Based - Planned SR ($MM) | DSP - Planned System Renewal ($MM) | Partial Funding - Planned SR ($MM) |
|---|---|---|---|
| **2019** | 249.79 | 73.72 | 73.72 |
| **2020** | 271.49 | 90.05 | 79.07 |
| **2021** | 267.75 | 103.06 | 74.64 |
| **2022** | 242.42 | 111.46 | 76.69 |
| **2023** | 225.12 | 124.12 | 82.48 |
| **2024** | 209.92 | 133.68 | 84.84 |
| **2025** | 209.37 | 169.94 | 116.07 |
| **2026** | 206.59 | 195.47 | 144.15 |
| **2027** | 209.73 | 222.88 | 173.93 |
| **2028** | 271.04 | 269.62 | 214.27 |
| **2029** | 300.55 | 299.09 | 272.90 |
| **2030** | 328.89 | 334.07 | 349.01 |
| **2031** | 348.66 | 358.53 | 447.74 |
| **2032** | 357.67 | 360.91 | 504.29 |
| **2033** | 352.11 | 359.96 | 527.28 |
| **2034** | 328.51 | 356.06 | 548.60 |
| **2035** | 311.23 | 362.79 | 558.68 |
| **2036** | 296.12 | 357.19 | 553.58 |
| **2037** | 297.57 | 364.52 | 549.34 |
| **2038** | 311.32 | 361.60 | 555.55 |

e) Please see Alectra Utilities' response G-Staff-104.

f) In the year 2028, Alectra Utilities projects that the opportunity to rehabilitate cable would no longer be feasible and the only renewal possible for cable is replacement. The cost of cable replacement is approximately five times more expensive than cable injection. Alectra Utilities' opportunity window to inject cable is finite and results in a significant cost savings over the long-term (2019-2038) relative to cable replacement. Funding the system renewal needs under Alectra Utilities' proposed plan mitigates the "snowplow" effect of capital costs for future customers.

**EP-2**

**Reference: Exhibit 1, Tab 3, Schedule 1, Page 5**

**Preamble: The Alectra RZs will continue on their current rate plan terms until such terms expire. Under those plans, Alectra Utilities is permitted to apply for: a) inflationary increases to rates, adjusted for an efficiency factor; and b) funding of incremental discrete capital projects through the Incremental Capital Module (“ICM”) mechanism.**

**Question:**

**a) Please provide a forecast of the capital that would have been available under the current Rate Plans 2020-2024**

**b) Please provide a table that compares the Status Quo (capital under an ICM) to the current request for each sub-utility/RZ and for Alectra over the period 2020-2024**

**Response:**

a) The materiality threshold calculation establishes the level of capital funding that a utility is expected to absorb within its funding from base rates outside of a rebasing application. The materiality threshold by year is provided in Table 3 of Exhibit 2, Tab 1, Schedule 3, and is $1.183B over the five year period, or approximately $236MM per year.

b) The calculation of the materiality threshold and maximum eligible incremental capital amount is the same under the ICM and M-factor proposal. Alectra Utilities has adopted this element of the OEB’s ICM Policy. The *status quo* is represented by the materiality threshold as described in part a). The determination of the level of capital that can be requested under an ICM is the same as the determination of the level of capital that can be requsted under the M-factor.

**EP-3**

**References: Exhibit 2, Tab 1, Schedule 1, Page 4; Exhibit 2, Tab 1, Schedule 3, Page 5**

**Preamble: (1) "The OEB determined that the ICM is unable to accommodate many of the investments needed to maintain Alectra Utilities' distribution system. *In particular, ICM funding is not available for "typical annual capital programs" or smaller projects that do not on their own meet an undefined, secondary materiality threshold. The cumulative cost for these types of necessary investments is significant*, and the lack of funding for such work through rates. is having a material impact on Alectra Utilities' distribution system." (EB-2017-0024, Decision and Order, April 6, 2018, p. 30.)**

**(2) "Custom IR is not a rate setting option available to Alectra Utilities during the rebasing deferral period. Further, the RRF framework was set several years prior to the update to the MAADs framework and related rate making in that context. However, the company's evolving capital needs are analogous to those distributors whose capital programs have been funded through Custom IR frameworks, accepted by the OEB."**

**Question:**

**a) Does Alectra agree, or not, that the current application seeks approval of a Custom IRM Plan? Please Discuss.**

**b) Please explain why Alectra is filing a CIR Plan without rebasing, include the precedential aspects of this request.**

**c) In support of Alectra's position set out at Exhibit 2 Tab 1 Schedule 3 Page 6, please provide the relevant extracts of the Board's guidelines and filing requirements and precedent decisions.**

**d) Did Alectra petition the Board following the MAADs decisions to request that it be allowed to file a CIR Plan without rebasing? Please provide copies of the relevant documents, including the Board response/direction.**

**Response:**

a) Please see Alectra Utilities' response to SEC-22.

b) Please see part a), above.

c) Please see:

- EP-3-Attach 1 - OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 - Incentive Rate-Setting Applications issued July 12, 2018;

- EP-3-Attach 2 - The MAADs Handbook, otherwise known as the Handbook to Electricity Distributor and Transmitter Consolidations, issued January 19, 2016;
- EP-3-Attach 3 - The OEB's Handbook for Utility Rate Applications, dated October 13, 2016;
- EP-3-Attach 4 - The Decision and Partial Accounting Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024), issued December 20, 2017;
- EP-3-Attach 5 - The Decision and Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024), issued April 6, 2018;
- EP-3-Attach 6 - The Decision and Rate Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024), issued May 3, 2018;
- EP-3-Attach 7 - The Partial Decision and Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016), issued December 20, 2018;
- EP-3-Attach 8 - The Decision and Interim Rate Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016), issued January 24, 2019;
- EP-3-Attach 9 - The Decision and Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016), issued January 31, 2019; and
- EP-3-Attach 10 - The Final Rate Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016), issued February 21, 2019.

d) Not applicable.

# EP-3

# ATTACH 1

# OEB's Filing Requirements for Electricity Distribution Rate Applications-Chapter 3-Incentive Rate-Setting Applications

# Issued July 12, 2018

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

# Ontario Energy Board

## Filing Requirements For

## Electricity Distribution Rate Applications

## - 2018 Edition for 2019 Rate Applications -

## Chapter 3

## Incentive Rate-Setting Applications

**July 12, 2018**

# Table of Contents

# Chapter 3 Filing Requirements for Incentive Rate-Setting Applications subject to the OEB's Index Adjustments

## 3.1 Introduction

On October 13, 2016, the OEB released its *Handbook for Utility Rate Applications* (the Handbook) to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates under the renewed regulatory framework (RRF). The Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications and is applicable to all rate regulated utilities, including electricity distributors, electricity transmitters, natural gas utilities and Ontario Power Generation. The OEB expects utilities to file rate applications consistent with the Handbook unless a utility can demonstrate a strong rationale for departing from it. The Handbook describes three incentive rate-setting (IR) methods established by the RRF: Price Cap IR, Custom IR and the Annual IR Index.

These filing requirements set out the OEB's expectations for electricity distributors' annual rate adjustment applications in between cost of service (CoS) applications under Price Cap IR, or the Annual IR Index, also known as incentive rate-setting mechanism (IRM) applications. These filing requirements replace the 2017 edition of the Chapter 3 Incentive Rate-Setting Filing Requirements for Electricity Distribution Rate Applications, dated July 20, 2017.

The key elements for the three rate-setting methods were set out in the Renewed Regulatory Framework for Electricity (RRFE) in the following table:

### *Table 1: Rate-setting Overview – Elements of the Three Methods*

<table>
<tr><th colspan="2"></th><th>Price Cap IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
<tr><td colspan="2">Term</td><td>5 years (rebasing plus 4 years).</td><td>Minimum term of 5 years.</td><td>No fixed term.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td colspan="3">The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo</td><td>Status quo, plus as needed to track capital spending against plan</td><td>Disposition limited to Group 1<br>Separate application for Group 2</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td></tr>
</table>

### 3.1.1 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2019 under IRM will be required to file their application by August 13, 2018. The OEB has assigned distributors seeking IRM rate adjustments effective May 1, 2019 to one of three application groupings noted below based on the expected level of complexity of the application. The length of time required to review an application is commensurate with its level of complexity. Applications of greater complexity will be expected to be filed first.

The OEB conducted a survey in May 2018 to identify the expected elements of an applicant's IRM application for the assignment of IRM filing deadlines. If a distributor expects that its application will be significantly more complex than it disclosed during the survey, it should advise the OEB and is encouraged to file in an earlier grouping.

Staggering the applications allows the OEB and other stakeholders to schedule resources to allow for adequate review of the applications. The deadlines for filing an IRM application have been determined so that, in the normal course of events, a decision and order will be issued in time for a May 1 implementation date.

The application deadlines are as follows:

- September 24, 2018
- October 15, 2018
- November 5, 2018

The assignment of distributors to these filing dates has been detailed in the cover letter accompanying these filing requirements.

### 3.1.2 Components of the Application Filing

Whether filing under Price Cap IR or the Annual IR Index, each application must include:

1. A manager's summary thoroughly documenting and explaining all rate adjustments requested.

2. The contact information for the application - the primary contact for the application may be a person within the applicant's organization other than the primary licence contact. The OEB will communicate with this person during the

course of the application. After completion of the application, the OEB will revert communication to the primary licence contact.

3. A completed rate generator model[1] and supplementary workforms[2] as applicable, provided by the OEB, both in Excel and Adobe PDF format.
4. A PDF copy of the current tariff sheet.
5. Supporting documentation cited within the application (e.g. excerpt of relevant past decisions and/or settlement agreements; validated reporting and record-keeping requirements (RRR) data pre-populated in the rate generator model; other RRR data referred to in the application; and, the revenue requirement workform (RRWF).[3]
6. A statement as to who will be affected by the application, including identification of any specific customer(s) or customer groups that are or will be affected by a particular request or proposal.
7. Confirmation of the applicant's internet address for purposes of viewing the application and related documents.
8. A statement confirming the accuracy of the billing determinants for pre-populated models.
9. A text-searchable Adobe PDF format for all documents.

### 3.1.3 Applications and Electronic Models

The models issued by the OEB assist the applicant in filing a rate application and provide formatting consistency across all applications.

For 2019 IRM applications, the OEB has taken steps to streamline the process further by pre-populating its models with distributor-specific RRR data, and by incorporating more automation with respect to the calculation of Global Adjustment (GA) and Capacity Based Recovery (CBR) charges and rate riders. The 2019 rate generator model will be

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[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in a Price Cap IR or Annual IR Index application.

[2] Includes the GA Analysis Workform, Revenue Cost Ratio Adjustment Workform and the Incremental Capital Module/Advanced Capital Module (ICM) (ACM) Workform, as applicable.

[3] The Revenue Requirement Workform was filed as part of the draft rate order in the last CoS application.

populated with a distributor's most recent tariff of rates and charges, load and customer data and Group 1 balances as reported through RRR. Distributors will be required to confirm the accuracy of the data. Remaining inputs will be marked with green input cells.

The OEB will provide passwords to distributors filing a 2019 IRM application to access their distributor-specific rate generator model through the OEB's website. Any distributor that did not receive an individual password, but wishes to file an IR application for the 2019 rate year, must notify the OEB as soon as possible.

The rate generator model will update base rates, retail transmission service rates and if applicable, shared tax saving adjustments. It will also calculate rate riders for the disposition of deferral and variance account balances.

The rate generator model continues to include a bill impact calculation by rate class, in which commodity rates based on time-of-use and regulatory charges are held constant. These will be based on the regulated price plan (RPP) prices at the time the rate generator model was published. A typical residential customer has been defined as consuming 750 kWh in accordance with the *Report of the Board – Defining Ontario's Typical Residential Customer*.

In addition to the rate generator model, all distributors must file the GA Analysis Workform. The workform compares the General Ledger principal balance to an expected principal balance based on monthly GA volumes, revenues and costs. The workform helps the OEB assess if the annual balance in Account 1589 is reasonable. One or all of the following models are required when applications involve certain additional requests.

A distributor seeking a revenue-to-cost ratio adjustment due to a previous OEB decision must continue to file the OEB's revenue-to-cost ratio adjustment workform in addition to the rate generator model.

For an incremental or pre-approved advanced capital module (ICM/ACM) cost recovery and associated rate rider(s), a distributor must file the Capital Module Applicable to ACM and ICM.

A distributor seeking to dispose of lost revenue amounts from conservation and demand management activities, during an IRM term, must file the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Workform.

Starting for the 2019 rate applications, distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must file the 1595

Analysis Workform. This new workform will help the OEB assess if the residual balances proposed for disposition are reasonable.

The models and workforms issued by the OEB are provided to assist the applicant in filing a rate application, and to provide consistent formatting for all distributors for greater efficiency of the review process. An applicant is responsible for the completeness and accuracy of its application. The applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The use of an OEB model does not guarantee that the OEB will approve the results. The OEB expects that the models and workforms be used by all distributors. If an applicant makes any changes to OEB models or workforms to address its own circumstances, it must highlight in the managers summary and provide justification for such changes.

## 3.2 Elements of the Price Cap IR and the Annual IR Index Plan

### 3.2.1 Annual Adjustment Mechanism

The annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains.[4] The components in the formula are also approved by the OEB annually. The formula is a rate adjustment equal to the inflation factor minus the distributor's X-factor.

*Inflation Factor*

In its *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* the OEB adopted a two factor industry-specific price index methodology. The inflation factor is based on two weighted price indicators (labour and non-labour) which provide an input price that reflects Ontario's electricity industry.

*X-factor*

The X-factor has two parts: a productivity factor and a stretch factor. The OEB has determined that the appropriate value for the productivity factor (industry total factor productivity) for the Price Cap IR and Annual IR Index is zero. For the stretch factor,

[4] Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013).

distributors will be assigned into one of five groups ranging from 0.0% to 0.6%. The most efficient distributor, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0%. All Annual IR Index applicants will be assigned a stretch factor of 0.6%.

Distributors shall use the 2018 rate-setting parameters as a placeholder until the stretch factor assignment and inflation factor for 2019 are issued by the OEB. OEB staff will update each distributor's rate generator model with the 2019 price cap parameters once they are available. Distributors will have an opportunity to comment on the accuracy of OEB staff's update as part of the application process.

#### *3.2.1.1 Application of the Annual Adjustment Mechanism*

The annual adjustment mechanism will apply to distribution rates (fixed and variable charges) uniformly across customer rate classes.

The annual adjustment mechanism will not be applied to the following components of delivery rates:

- Rate Adders
- Rate Riders
- Low Voltage Service Charges
- Retail Transmission Service Rates
- Wholesale Market Service Rate
- Rural and Remote Rate Protection Benefit and Charge
- Standard Supply Service – Administrative Charge
- Capacity Based Recovery
- MicroFIT Service Charge
- Specific Service Charges
- Transformation and Primary Metering Allowances[5]
- Smart Metering Entity Charge

[5] And any other allowances the OEB may determine.

### 3.2.2 Revenue-to-Cost Ratio Adjustments

OEB decisions regarding CoS rate applications may sometimes prescribe a phase-in period to adjust the revenue-to-cost ratios. The OEB's revenue-to-cost ratio adjustment workform and rate generator model include schedules for a distributor to adjust the revenue-to-cost ratio if previously approved by the OEB. The model will adjust base distribution rates before the application of the price cap adjustment.

### 3.2.3 Rate Design for Residential Electricity Customers

On April 2, 2015, the OEB released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*[6], which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. The transition began in 2016 and in most cases will be implemented over a period of four years.

The OEB issued decisions affecting 2016, 2017 and 2018 rates for Price Cap IR and Annual Index IR applicants consistent with this policy. In this fourth year of transition, the distributor must follow the approach set out in Tab 16. Rev2Cost_GDPIPI of the rate generator model.

Distributors are expected to propose a fully fixed rate design for new charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity.[7] Pass-through costs (e.g. transmission rates, Low Voltage charges, and Group 1 deferral and variance accounts) and LRAMVA amounts are to continue to be recovered as variable charges because they predominantly relate to energy charges. Previously approved distribution-specific charges or rate riders on a distributor's tariff should remain unchanged until they expire, even if they were declared interim.

#### *Residential Rate Design – Exceptions and Mitigation*

In order to support the initial transition to fully fixed distribution rates, the OEB designed two tests to determine when mitigation should be proposed – a threshold test for the

[6] EB-2014-0210

[7] Examples of distribution-specific charges include Shared Tax Savings, Z-Factors, ACM and ICM rate riders.

change in the fixed charge, and an overall bill impact test. The OEB is requiring distributors once again to calculate and report on the rate impacts of the change in 2019 so that mitigation strategies may be employed to smooth the transition for the customers most impacted, such as those that consume less electricity.

In 2019, the last year of transition for most distributors, a distributor is expected to apply to extend its OEB-approved transition period if necessary, to continue to comply with the policy. For 2019, the monthly service charge would have to rise more than $4 per year in order to affect the length of the transition to fixed rates. It is expected that in most cases, only an additional transition year would be required to make the changes within the $4 impact threshold identified in the policy. A distributor shall propose an alternative or additional strategy in the event that an additional transition year is insufficient. Consistent with OEB policy regarding mitigation, a distributor may propose as part of its application that no extension is necessary; such a position must be substantiated with reasons.

While the rate design is revenue neutral across the residential class, the impact on individual customers will vary with consumption. The OEB requires distributors to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those residential RPP customers who are at the 10th percentile of overall consumption.[8] That is, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis. Sorting or segmentation of residential class data by consumption level will be required. Distributors must provide a description of the method they used to derive the 10th consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers).

If the total bill impact of the elements proposed in the application is 10% or greater for RPP customers consuming at the 10th percentile, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required. The distributor will have the ability to propose the approach to mitigation, including, but not limited to, the option to extend the transition to fixed rates over a longer period. A detailed rationale must be provided.

It is the OEB's expectation that the approach to mitigation will target only the residential class, to avoid any material cross-subsidy between classes.

[8] To a minimum of 50 kWh per month.

Beyond the issue of residential rate design specifically addressed in this section, distributors are reminded that they must file a mitigation plan if total bill increases for any customer class exceed 10%.

### 3.2.4 Electricity Distribution Retail Transmission Service Rates

In preparing its application, the distributor should refer to the OEB's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0, issued June 28, 2012.*[9]

The OEB's rate generator model will assist in calculating the distributor's class-specific RTSRs. The rate generator model will reflect the most recent uniform transmission rates (UTRs) approved by the OEB.[10] Once any January 1, 2019 UTR adjustments have been determined, OEB staff will adjust each distributor's 2019 RTSR section of the rate generator model to incorporate these changes where applicable. The rate generator model will also reflect the most recent sub-transmission rates approved by the OEB.[11] Likewise, OEB staff will update these rates as they become available.

### 3.2.5 Review and Disposition of Group 1 Deferral and Variance Account Balances

*The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (EDDVAR) provides that under the Price Cap IR or the Annual IR Index, the distributor's Group 1 audited account balances will be reviewed, and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed. Consistent with a letter from the OEB on July 25, 2014, distributors may elect to dispose of Group 1 account balances below the threshold. Distributors should assess the practicality of disposing what may be small balances for one or more classes; for further guidance on considerations relevant to rate riders, see Appendix B.

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[9] Originally issued October 22, 2008.

[10] Decision and Rate Order, EB-2017-0359, February 1, 2018.

[11] Hydro One Networks Inc., Decision and Rate Order, EB-2016-0081, December 21, 2016; other distributors sub-transmission rates are approved in their decision and order.

In their application, distributors must include Group 1 balances as of December 31, 2017 to determine if the threshold has been exceeded. The continuity schedule, found on Tab 3 of the rate generator model, must be completed as part of the application.

Group 1 consists of the following Uniform System of Accounts (USoA):

- 1550 Low Voltage Account
- 1551 Smart Metering Entity Charge Variance
- 1580 RSVA Wholesale Market Service Charge Account
    - 1580 Variance WMS, Sub-Account CBR Class A
    - 1580 Variance WMS, Sub-Account CBR Class B
- 1584 RSVA Retail Transmission Network Charges Account
- 1586 RSVA Retail Transmission Connection Charge Account
- 1588 RSVA Power Account
- 1589 RSVA Global Adjustment Account
- 1595 Disposition and Recovery/Refund of Regulatory Balances Account

Distributors must provide an explanation if the account balances on *Tab 3. Continuity Schedule* of the rate generator model differ from the account balances in the trial balance reported through the RRR and the audited financial statements and which have been reflected in the prepopulated rate generator model.

The OEB expects that no adjustments will be made to any deferral and variance account (DVA) balances previously approved by the OEB on a final basis. Distributors must make a statement in their application as to whether or not any such adjustments were made. If adjustments have taken place, a distributor must provide explanations in its application for the nature and amounts of the adjustments and include supporting documentation under a section titled “Adjustments to Deferral and Variance Accounts”.

If the RRR balances do not agree to the year end balances in the continuity schedule, a distributor must reconcile and explain the differences.

The rate generator model will calculate the DVA disposition threshold using the last full year of actual load data as reported through the RRR. The default billing determinants used in the calculation of the Group 1 DVA rate riders will also be based on recent load data. The use of recent actuals should reduce residual variances by reflecting changes in customer class composition. A distributor may propose an alternative method with supporting rationale. In that case, revisions to the rate generator model may be required.

All GA rate riders will be calculated on an energy basis (kWh) – (see section 3.2.5.2).

EDDVAR states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

#### *3.2.5.1 Wholesale Market Participants*

A wholesale market participant (WMP) refers to any entity that participates directly in any of the Independent Electricity System Operator (IESO) administered markets. These participants settle commodity and market-related charges with the IESO even if they are embedded in a distributor's distribution system. As a consequence, a distributor must not allocate any balances to these customers from Account 1580 RSVA - Wholesale Market Services Charge, Account 1580 Variance WMS, Sub-Account CBR Class B, Account 1588 RSVA - Power, and Account 1589 RSVA - Global Adjustment to a WMP.

A distributor must also ensure that rate riders are appropriately calculated for the following remaining charges that are still settled with a distributor. These include Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances.

#### *3.2.5.2 Global Adjustment*

*Class B and A Customers*

Most customers pay the GA charge based on the amount of electricity they consume in a month (kWh). These customers are referred to as Class B. Customers who participate in the Industrial Conservation Initiative (ICI), referred to as Class A, pay GA based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period.[12] Distributors that settle GA costs with Class A customers on the basis of actual GA prices, shall allocate no GA variance balance to these customers for the period that customers were designated Class A.

For non-RPP Class B customers, the GA variance account (Account 1589) captures the difference between the amounts billed (or estimated to be billed) by the distributor and the actual amount paid by the distributor to the IESO (or host distributor) for those customers.

When clearing balances from the GA variance account, distributors must establish a separate rate rider included in the delivery component of the bill that would apply prospectively to non-RPP Class B customers. Effective in 2017, the billing determinant and all the rate riders for the GA were calculated on an energy basis (kWh) regardless of the billing determinant used for distribution rates for the particular class.

The rate generator model will allocate the portion of Account 1589 GA to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general GA rate rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transition between Class A and Class B during the disposition period.

*GA Analysis Workform*

Starting for 2018 rate applications, all distributors were required to complete the GA Analysis Workform. The new workform will help the OEB assess if the annual balance in Account 1589 is reasonable. The workform compares the General Ledger principal balance to an expected principal balance based on monthly GA volumes, revenues and costs.

A discrepancy between the actual and expected balance may be explained and quantified by a number of factors, such as an outstanding IESO settlement true-up payment. The explanatory items should reduce the discrepancy and provide distributor-specific information to the OEB. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition is

[12] As of July 1, 2015, per O.Reg 429/04, an eligible customer with a maximum hourly demand over three megawatts, but less than five megawatts, can elect to become a Class A for an applicable adjustment period of one year. Effective January 1, 2017, the ICI expanded to include all electricity users with an average monthly peak demand over 1 MW. In April 2017, the ICI further reduced the ICI threshold to 500 kW to make targeted manufacturing and industrial sectors, including greenhouses, eligible to opt-in to the ICI.

approved. Unexplained discrepancies should be calculated separately for each calendar year and any unexplained discrepancy for each year greater than +/- 1% of total annual IESO GA charges will be considered material.

The GA Analysis Workform is available on the OEB's web site and is to be filed in live Microsoft Excel format.

*Description of Settlement Process*

A distributor must support its GA claims with a description of its settlement process with the IESO or host distributor. The description should include the following:

- The GA prices the distributor uses to bill (and record unbilled entries) to its various customer classes (i.e. 1st estimate, 2nd estimate or actual).

  As part of this description, the distributor shall confirm that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers in each customer class. In addition, where the same GA rate is not used for non-RPP Class B customers in all customer classes, the distributor shall explain what GA rate is applied to each customer class.

- The distributor's process for providing consumption estimates to the IESO as part of its RPP settlement process and the RPP settlement process used to true-up estimated amounts to actual amounts.

  Specifically, the distributor should indicate what type of data is used to determine the volume estimates of RPP customers at different TOU periods or Tier 1 and 2 blocks. A distributor must also provide the time when actual data becomes available and its true-up process.

- The distributor's method for estimating RPP and non-RPP consumption, as well as its treatment of volumes related to embedded generation or embedded distribution customers.

- The distributor's internal control tests, if any, in validating estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments.

Distributors are expected to use accrual accounting.

*Description of Accounting Methods and Transactions for Each Year in which the Applicant is Requesting the Balances for Disposition*

A distributor must provide the OEB with a description of its financial accounting practices as they relate to its initial recording of transactions in Commodity Accounts 1588 and 1589. In addition, a distributor must disclose the nature, timing, and dollar impact of any subsequent adjustments recorded after the reporting period that adjust the initial transactions from preliminary estimates to actual figures based on consumption data. In order to provide the above-noted information to the OEB, distributors must complete the GA Analysis Workform for each applicable fiscal year subsequent to the most recent year in which Accounts 1588 and 1589 were approved for disposition on a final basis by the OEB.

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must make a proposal to exclude these customer classes from the allocation of the balance of account 1589 RSVA GA and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the GA rate rider as they did not contribute to the accumulation of the balance of account 1589 RSVA GA.

#### *3.2.5.3 Commodity Accounts 1588 and 1589*

*RPP Settlement True-Ups*

Effective May 23, 2017, per the OEB's letter titled Guidance on Disposition of Accounts 1588 and 1589, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts. In doing so, distributors are to follow the guidance provided in the above noted letter.

*Certification of Evidence*

Given issues that have arisen with commodity accounts 1588 RSVA Power and 1589 RSVA GA balances, the OEB now requires a certification by the Chief Executive Officer (CEO), or Chief Financial Officer (CFO), or equivalent. The application must include a certification that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.

#### *3.2.5.4 Capacity Based Recovery (CBR)*

Distributors should follow accounting guidance on the disposition of CBR variances. In *Tab 3 Continuity Schedule* of the rate generator model, the distributor must indicate whether it had any Class A customers during the period where the Account 1580 CBR

Class B Sub-account balance accumulated. If yes, a separate rate rider will be calculated in *Tab 6.2 CBR B* in the rate generator model. However, in the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580, Sub-account CBR Class B will be added to the Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders (accounting guidance to be updated to reflect this change). The balance in Sub-Account CBR B must be disposed over the default period of one year. If the distributor did not have any Class A customers during the period where the Account 1580 CBR Class B sub-account balance accumulated, the rate generator model will also transfer the sub-account balance to Account 1580 WMS control account and include the CBR amounts as part of the general purpose Group 1 DVA rate riders. Account 1580 Sub-Account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance.

The rate generator model will also allocate the portion of Account 1580, Sub-account CBR Class B to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general CBR Class B rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transition between Class A and Class B during the disposition period.

### 3.2.6 Lost Revenue Adjustment Mechanism Variance Account

The LRAMVA is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

On April 26, 2012, the OEB issued the CDM Guidelines (2012 CDM Guidelines). The 2012 CDM Guidelines provide details on the LRAMVA for the 2011 to 2014 period. Accounting guidelines on the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the 2012 CDM Guidelines for further details.

On May 19, 2016, the OEB issued the *Report of the OEB: Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand*

*Savings from Conservation and Demand Management Programs* (the LRAMVA Report). The OEB updated its policy on how peak demand savings from energy efficiency and demand response programs should be treated for LRAMVA purposes. The OEB expects that distributors refer to the LRAMVA Report and follow the new policy.

The LRAMVA Workform provides distributors with a consistent approach to calculate LRAMVA. The LRAMVA Workform consolidates information that distributors have received from the IESO.

In December 2016, the OEB indicated in various decisions[13] that changes to an approved LRAMVA amount were not permitted. This policy affects the treatment of verified savings adjustments that can be claimed by distributors. If an LRAMVA amount was approved, the persistence of the savings adjustment(s) can only be claimed on a go-forward basis.[14] Distributors cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB. For example, if a distributor has received approval of its 2016 LRAMVA balance, excluding 2016 savings adjustments, the distributor must forgo any LRAMVA amounts related to the 2016 savings adjustments as the 2016 LRAMVA balance was approved by the OEB on a final basis.

#### *3.2.6.1 Disposition of the LRAMVA*

At a minimum, distributors must apply for the clearance of its energy and/or demand related LRAMVA balances attributable to energy efficiency programs in a CoS application. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

The distributor shall compare the OEB-approved LRAMVA threshold to actual CDM results at a rate class level. The variances calculated from this comparison shall be recorded in separate Sub-Accounts for the applicable customer rate classes. Distributors

[13] EB-2016-0075 (Guelph Hydro 2017 IRM) and EB-2016-0080 (Hydro One Brampton 2017 IRM).

[14] See EB-2016-0214 for an example (North Bay Hydro 2017 IRM).

must continue to track the variances between the OEB-approved LRAMVA threshold and actual CDM results in the LRAMVA for the 2015-2020 period.[15]

In reference to the LRAMVA Report, Demand Response 3 (DR3) savings should generally not be included in the LRAM savings unless supported by empirical evidence to be reviewed in a CoS application. Any requests for approval of lost revenues related to peak demand savings from demand response programs can only be part of a rebasing application due to the complexity and unique nature of the calculation of lost revenues from peak demand savings. As a result, lost revenues related to peak demand savings from demand response programs will nor be evaluated in an IRM rate application. Those distributors who are planning to seek recovery of lost revenue associated with DR3 and have recorded amounts to the end of December 31, 2014 in Account 1568 may transfer the accumulated amounts to Sub-Account 1568-0001 LRAMVA Demand Response, or forego recovery, in accordance with the OEB's updated accounting guidance issued on July 18, 2017. However, if a distributor has already received OEB approval for disposition of Account 1568 as of December 31, 2014 on a final basis, no amounts are to be recorded in Account 1568 Sub-Account 1568 LRAMVA Demand Response. This Sub-Account is only available to distributors for transferring amounts from Account 1568 LRAMVA with respect to savings for period from 2011-2014, and only if they have not already received OEB approval for disposition of Account 1568 on a final basis, for amounts recorded for 2011-2014.

The following information should be provided in the application:

- A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition.
- A statement confirming that LRAMVA was based on verified savings results that are supported by the distributor's Final CDM Annual Report and Persistence Savings Report issued by the IESO. Both reports must be filed in Excel format. A statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation.
- A summary table showing the principal and carrying charges amounts by rate class and the resultant rate riders for each rate class. Projected carrying charges related to the disposition should be calculated in the LRAMVA Workform.
- A statement confirming the period of rate recovery. Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not

[15] Conservation and Demand Management Requirement Guidelines for Electricity Distributors, December 19, 2014 (EB-2014-0278).

generate significant rate riders.

- Details for the forecast CDM savings included in the LRAMVA calculation including reference to the OEB's approval, or an explanation if there are no forecast CDM savings
- A statement confirming how the rate class allocations for actual CDM savings were determined by customer class and program each year. Documentation (e.g., tables supporting the rate class allocations) should be filed in Tab 3-a of the LRAMVA workform.
- A statement confirming whether additional documentation or data was provided in support of projects that were not included in the distributor's Final CDM Annual Report (i.e., street lighting projects). Distributor billing data by project must be included in the workform in Tab 8, as applicable. For distributor street lighting project(s) which may have been completed in collaboration with local municipalities:
    - Explain the methodology to calculate street lighting savings;
    - Confirm whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; and,
    - Confirm whether the street lighting project(s) received funding from the IESO and provide the appropriate net-to-gross assumption used to calculate street lighting savings.

An application to dispose of the balance in an LRAMVA may only be filed as part of an Annual IR Index application if the OEB's decision for the distributor's last CoS (or settlement agreement approved by the OEB) has a clear description of class-specific CDM adjustments made to the load forecast to be used in the calculation of the LRAMVA balance. Any LRAMVA applications determined by the OEB to be more complicated than appropriate for an Annual IR Index application will be bifurcated and heard separately from the Annual IR Index application.

### 3.2.7 Tax Changes

OEB policy, as described in the OEB's 2008 report entitled Supplemental Report of the *Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the Supplemental Report), prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. These amounts will be refunded to or recovered from customers over a 12-month period. If applicable, applicants must complete sheets 8 and 9 of the rate generator model. The rate generator model will calculate an applicable rate rider using the appropriate customer class data underlying the OEB approved rates. A rate rider to four decimal places must be generated for all applicable customer classes in order to dispose of the amounts. If one or more customer classes does not generate a rate rider to the fourth decimal place, the entire 50/50 sharing amount will be transferred to Account 1595 for disposition at a future date.

### 3.2.8 Z-factor Claims

Price Cap IR applicants have the ability to include in their application a request to recover costs associated with unforeseen events that are outside the control of a distributor's ability to manage. The cost to a distributor must be material and its causation clear. Costs are to be recorded in Account 1572, Extraordinary Events Costs. To recover these amounts, a distributor must follow the guidelines discussed in section 2.6 of the *Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008. The materiality thresholds, described in the above noted OEB report, must be met on an individual event basis in order for the distributor to apply for recovery of the relevant costs.

#### *3.2.8.1 Z-factor Filing Guidelines*

A distributor must submit evidence that the costs incurred meet the three eligibility criteria. A distributor must also:

- Notify the OEB promptly by letter to the Board Secretary of all Z-factor events. Failure to notify the OEB within six months of the event may result in disallowance of the claim.
- Apply to the OEB for any cost recovery of amounts recorded in the OEB-approved deferral account claimed under Z-factor treatment. This will allow the OEB and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the OEB may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by

extraordinary events is genuinely incremental to their experience or reasonable expectations.

- Demonstrate that the costs were incurred within a 12-month period and are incremental to those already being recovered in rates as part of ongoing business exposure risk.

#### 3.2.8.2 Z-factor Accounting Treatment

The distributor will record eligible Z-factor cost amounts in Account 1572, Extraordinary Event Costs, of the OEB's USoA contained in the Accounting Procedures Handbook (APH) for electricity distributors. Monthly carrying charges shall be recorded in Account 1572. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate Sub-Account of this account. The rate of interest shall be the rate prescribed by the OEB for deferral and variance accounts for the respective quarterly period published on the OEB's web site.

#### 3.2.8.3 Recovery of Z-Factor Costs

As part of its claim, a distributor must outline the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocation methods. Recovery will be through a rate rider.[16] The request must specify whether the rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the length of the disposition period and a rationale for this proposal. As discussed at section 3.2.3, any new rate riders that apply to residential classes must only be applied on a fixed basis. A detailed calculation of the incremental revenue requirement and resulting rate rider(s) must be provided.

[16] See Appendix B.

## 3.3 Elements Specific only to the Price Cap IR Plan

### 3.3.1 Advanced Capital Module

On September 18, 2014, the OEB issued the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*[17] (ACM Report). The Advanced Capital Module (ACM) reflects an evolution of the Incremental Capital Module (ICM) adopted by the OEB in 2008. The ACM approach seeks to increase regulatory efficiency during the Price Cap IR term and provides a distributor with the opportunity to smooth out its capital program over the five year period between CoS applications.

A distributor must make any ACM requests as part of a CoS application. At that time, the need for and prudence of any such requests will be determined. Cost recovery (i.e. rate riders) for qualifying ACM projects will be determined in the subsequent Price Cap IR application for the year in which the capital investment will come into service.

While an ACM request must be made in a CoS application, a Price Cap IR application is the vehicle in which an applicant may calculate the rate rider to recover the amounts approved in a CoS application. A distributor seeking cost recovery through a Price Cap IR application should carefully review the ACM Report before making such a request.

A distributor approved for an ACM in its most recent CoS application must file its most recent calculation of its regulated return[18] at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed. Therefore, any approvals provided for an ACM in a CoS application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The same means test shall also apply going forward for new projects proposed as ICMs during the Price Cap IR term.

A distributor meeting this requirement must provide for the relevant project or projects updated cost projections, confirmation that the project or projects are on schedule to be completed as planned and an updated ACM/ICM module in Excel format. If the proposed cost recovery differs significantly from the pre-approved amount, the

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[17] EB-2014-0219

[18] RRR 2.1.5.6

distributor must provide a detailed explanation. Any changes in the scope or timing of the project must be clearly explained and justified.

If the updated cost projections are 30% greater than the pre-approved amount, the distributor must treat the project as a new ICM project and re-file the business case and other relevant material in the applicable IR year.

As part of the distributor’s subsequent rebasing application, the OEB will carry out a prudence review of the actual costs to determine the amounts to be incorporated in rate base. At that time, the OEB will also make a determination regarding the treatment of differences between forecast and actual spending during the remainder of the IRM plan term (i.e. if any true-up is required).

On January 22, 2016, the OEB issued the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report*. This report made changes to the materiality threshold on which ACM and ICM proposals are assessed, but otherwise does not alter the requirements for ACM and ICM proposals by an applicant. The Supplemental Report also reaffirms the applicability of the half-year rule for determining the return of and return on capital in the first year that assets enter service.

An associated and updated Capital Funding Module to reflect the changes to the materiality threshold was also issued along with the Supplemental Report, and is available on the OEB’s website. A distributor filing for ACM/ICM rate riders must use the current model.

### 3.3.2 Incremental Capital Module

The ICM remains available to electricity distributors opting for Price Cap IR. The ICM is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold defined below. The ICM is available for discretionary and non-discretionary projects. The ICM is also available for capital projects that were not included in the distributor’s last filed Distribution System Plan. Even for approved ACM projects, an ICM is available if an updated ACM budget exceeds the approved ACM budget by 30%. Distributors with multiple capital projects should consider the Custom IR option to address capital needs in the context of their Distribution System Plan, rather than submit multiple ICM applications or ICM applications that consistently use up a substantial amount of the eligible available capital amount.

The ICM is not available for incremental funding if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates.

The requested amount for an ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates and satisfy the eligibility criteria of materiality, need and prudence set out in section 4.1.5 of the ACM Report.

<table>
<tr><th>Criteria</th><th>Description</th></tr>
<tr><td>Materiality</td><td>A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.<br><br>Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.</td></tr>
<tr><td>Need</td><td>The distributor must pass the Means Test (as defined in the ACM Report).<br><br>Amounts must be based on discrete projects, and should be directly related to the claimed driver.<br><br>The amounts must be clearly outside of the base upon which the rates were derived.</td></tr>
<tr><td>Prudence</td><td>The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.</td></tr>
</table>

#### *3.3.2.1 ICM Filing Requirements*

The OEB requires that a distributor requesting relief for incremental capital during the IRM plan term include comprehensive evidence to support the need, which should include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor.
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers.
- Justification that amounts being sought are directly related to the cause, which must be clearly outside of the base upon which current rates were derived.
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth).
- Details by project for the proposed capital spending plan for the expected in-service year.
- A description of the proposed capital projects and expected in-service dates.
- Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project.
- Calculation of each incremental project's revenue requirements that will be offset by revenue generated through other means (e.g. customer contributions in aid of construction).
- A description of the actions the distributor would take in the event that the OEB does not approve the application.
- Calculation of a rate rider to recover the incremental revenue from each applicable customer class. The distributor must identify and provide a rationale for its proposed rider design, whether variable, fixed or a combination of fixed and variable riders. As discussed at section 3.2.3, any new rate rider for the residential class must be applied on a fixed basis.

### 3.3.2.2 ACM/ICM Materiality Threshold

The ACM/ICM materiality threshold is discussed in section 4.5 of the supplemental report.

The OEB determined that the following formula is to be used by a distributor to calculate the materiality threshold:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where $n$ is the number of years since the CoS rebasing. Many of the parameters remain unchanged from the original formula except for the following:

- the growth factor $g$ is annualized
- the dead band $X$ has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

### 3.3.2.3 Assessment of Materiality

In the ACM report, the OEB mentioned that the eligible incremental capital amount sought for recovery should be capital in excess of the ACM/ICM materiality threshold defined in section 3.3.2.2. This threshold level of capital expenditures is the amount that a distributor should be able to manage with its current rates, growth in demand and normal volatility in business conditions. Accordingly, the materiality threshold value, as calculated using the formula discussed in section 4 of the ACM report, marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the forecasted 2019 total capital expenditures and the ACM/ICM materiality threshold.

For individual projects included within an ACM/ICM request, it is not appropriate to apply the materiality thresholds established in the Chapter 2 Filing Requirements[19] for the purpose of evaluating the materiality of an individual project. These materiality thresholds are for the purpose of variance explanations for annual changes to rate

[19] *Section 2.0.8*

base, capital expenditures and operations, maintenance and administration costs as part of a CoS rate application.

In the Funding of Capital Report[20], the OEB adopted an approach establishing the following three principles with respect to the eligibility of a capital project for ACM/ICM treatment:

(1) minor expenditures in comparison to the overall capital budget should not be considered eligible for ICM treatment;

(2) a certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget; and

(3) the project amount being proposed for recovery should be significant within the context of the distributor's overall capital budget.

For merged utilities, the above principles are applicable to the merged distributor, not the individual rate zones.

#### *3.3.2.4 Application of the Half-Year Rule*

The OEB's general guidance on the application of the half-year rule was originally provided in the supplemental report. In that report the OEB determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IRM plan term. This approach is unchanged in the new ACM/ICM policy. However, the OEB's approach in decisions has been to apply the half-year rule in cases in which the ICM request coincides with the final year of a distributor's IRM plan term.[21]

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[20] EB-2014-0219 Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module September 18, 2014 p.17.

[21] EB-2010-0130, Guelph Hydro Electric Systems Inc., Decision and Order, p. 15.

#### 3.3.2.5 ACM/ICM Accounting Treatment

The distributor will record eligible ICM amounts in Account 1508 – Other Regulatory Asset, Sub-Account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal construction work in progress (CWIP) accounting treatment will apply until these assets go into service and are eligible to be recorded in the 1508 Sub-Accounts listed below.

Distributors shall record actual amounts in the following Sub-Accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures
- Account 1508 – Other Regulatory Assets, Sub-Account Depreciation Expense
- Account 1508 – Other Regulatory Assets, Sub-Account Accumulated Depreciation
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues

The distributor shall also record monthly carrying charges in the following Sub-Accounts. Carrying charge amounts are calculated by applying simple interest to the monthly opening balances:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures, Carrying charges
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges

The applicable rate of interest for deferral and variance accounts for the respective quarterly period is prescribed by the OEB and published on the OEB’s web site.

All Sub-Accounts should be used for both approved ACM and ICM projects. If the OEB approves the true-up of any variances for ACM/ICM projects at the next CoS application, the recalculated revenue requirement relating to the actual ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period, plus the carrying charges in the respective Sub-Accounts. These variances would then be refunded to, or collected from, customers through rate riders.

#### 3.3.2.6 Rate Generator and Supplemental Filing Module for ACM/ICM

The filing module for ACM/ICM will assist the distributor in calculating the distributor's threshold. The distributor will then tabulate the value of its eligible investments and compare this to the threshold result to determine the amount that would be eligible for recovery. Once all tabs are completed and listed in the filing module for ACM/ICM, the tabulated revenue requirement will be converted into class-specific rate riders. The rate riders will need to be added to Tab 18 – Additional Rates – of the rate generator model in order for them to be displayed on the Tariff of Rates and Charges.

### 3.3.3 Treatment of Costs for 'eligible investments'

On March 28, 2013, the OEB issued *Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements* (Chapter 5). As noted in section 5.0.5, Chapter 5 supersedes the *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence*.

As indicated in the cover letter to Chapter 5 dated March 28, 2013, distributors who have yet to file under Chapter 5 will continue to be able to record renewable energy generation costs and smart grid development costs in the deferral accounts that were established for that purpose. However, no new deferral accounts for these types of expenditures will be established. Distributors under Price Cap IR who have yet to file a CoS application containing a consolidated capital plan pursuant to Chapter 5 will continue to be able to request advance funding through a funding adder for renewable generation connection costs and smart grid development costs. Where a distributor seeks a funding adder, sufficient information must be provided to allow the OEB to assess the need for the mechanism and the nature and quantum of the costs to be collected from ratepayers and the basis for calculating the funding adder.

The costs recovered through the funding adder will be subject to a prudence review in the first CoS application following the implementation of the funding adder. Distributors should refer to Section 2.0.9 of the revised Chapter 2 Filing Requirements for further information on materiality levels for requests of provincial funding for renewable generation connections.

Distributors proposing to file an Annual IR Index application must make a Chapter 5 filing within five years of the date of the most recent OEB decision approving their rates in a CoS proceeding and are required to do so at five year intervals thereafter while using the Annual IR Index method.

### 3.3.4 Conservation and Demand Management Costs for Distributors

CDM activity is funded either through IESO Contracted Province Wide CDM Programs, or through an OEB-approved CDM program.

### 3.3.5 Off-ramps

For each of the OEB's three rate-setting options, a regulatory review may be triggered if a distributor's earnings are outside of a dead band of +/- 300 basis points from the OEB-approved return on equity. The OEB monitors results filed by distributors as part of their reporting and record-keeping requirements and determines if a regulatory review is warranted. Any such review will be prospective, and could result in modifications, termination or the continuation of the respective Price Cap IR or Annual IR Index plan for that distributor.

A distributor whose earnings are in excess of the dead band is expected to refrain from seeking an adjustment to its base rates through a Price Cap IR or Annual IR Index plan. If a distributor whose earnings are in excess of the dead band nevertheless applies for an increase to its base rates, the OEB expects it to substantiate its reasons for doing so. The applicant should anticipate that the level of earnings will be raised as an issue in the application.

A distributor may choose to file only for disposition of Group 1 deferral and variance account balances in accordance with OEB policies, without applying for adjustments to its base rates.

## 3.4 Specific Exclusions from Price Cap IR or Annual IR Index Applications

The IRM application process is intended to be mechanistic in nature. For this reason, the OEB has determined that the IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- Rate Harmonization, other than that pursuant to a prior OEB decision
- Disposition of the balance of Account 1555 – Smart Meter Capital Costs, Sub-Account Stranded Meter Net Book Value
- Changes to revenue-to-cost ratios, other than pursuant to a prior OEB decision
- Loss Factor Changes
- Establishing or changing Specific Service Charges
- Loss Carry Forward Adjustments to PILs/Taxes
- Disposition of Group 2 Deferral and Variance Accounts
- Loss of Customer Load

These items are to be addressed in the distributor's next CoS application. The exclusions above also apply to the Annual IR Index plan. In addition, distributors seeking adjustments that are inconsistent with OEB policy should consider whether one of the other rate-setting options is more appropriate. As indicated in the Handbook, distributors filing under the Annual IR Index plan must file a separate, stand-alone application for the review and disposition of Group 2 Deferral and Variance Accounts.

# Appendix A: Application of Recoveries in Account 1595

When approval for disposition of deferral and variance account balances is received from the OEB, the approved amounts of principal and carrying charges are transferred to Account 1595 for that rate year.

Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year only once, on a final basis. Distributors are expected to seek disposition of the audited account balances a year after a rate rider's sunset date has expired. No further transactions are expected to flow through the Account 1595 Sub-accounts once the residual balance has been disposed.

*1595 Analysis Workform*

Starting for the 2019 rate applications, distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must complete the 1595 Analysis Workform. The new workform will help the OEB assess if the residual balances in Account 1595 Sub-accounts for each vintage year are reasonable. The workform compares principal and interest amounts previously approved for disposition to the residual balances remaining after amounts have been recovered/refunded to customers through rate riders.

Initially, residual balances will be assessed for materiality and could prompt further review before disposition is approved. Balances in Account 1595 will first be assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts (if applicable). A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material.

Material residual balances will require further analysis, consisting of separating the components of the residual balances by each applicable rate rider[22] and by customer rate class. Distributors are expected to provide detailed explanations for any significant residual balances attributable to specific rate riders for each customer rate class. Explanations must include for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed.

[22] Residual account balances will be made up of amounts relating to at least two rate riders, i.e. the GA Rate Rider and the DVA Rate Rider.

The 1595 Analysis Workform is available on the OEB's web site and is to be filed in live Microsoft Excel format.

# Appendix B: Rate Adder versus Rate Rider

*Rate Adder*

A rate adder (or funding adder) is a tool designed to provide advance funding on an interim basis to distributors for certain investments or expenses as prescribed by the OEB and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the OEB. Approval of a rate adder does not constitute regulatory approval of any costs actually incurred. The prudence of incurring such costs is examined, and the costs may be approved in whole or in part, at the time at which the distributor brings the matter forward for regulatory review.

Rate adders are identified and listed separately on a distributor's tariff of rates and charges and may have a termination date.

*Rate Rider*

A rate rider differs from a rate adder in that it is designed to recover or refund OEB-approved amounts following a review of the proposed costs to determine that it is reasonable for the distributor to incur and recover them. Rate riders are identified and listed separately on a distributor's tariff of rates and charges, with an explicit termination date.

*Treatment of Negligible Rate Adders and Rate Riders*

Rate adders and rate riders normally apply to one or more select rate classes on a fixed basis, a volumetric basis or a combination of both. A rate adder or rate rider is usually determined by dividing the OEB-approved allocated amounts by the OEB-approved forecast or historical energy use or demand.

Occasionally, the calculated rate adders or rate riders for one or more rate classes may be negligible. In the event where the calculation of any rate adder or rate rider results in a volumetric rate rider that rounds to zero at five significant digits (i.e., the fourth decimal place) per kWh or per kW, the entire OEB-approved amount for recovery or refund will typically be recorded in a USoA account to be determined by the OEB for disposition in a future rate setting. Distributors may propose alternatives to this approach in the event that there is a significant discrepancy in the size of the riders among classes (e.g., if a rider is of a non-negligible size for one or more classes, but negligible or insignificant for another class).

# Appendix C: Key References

*The documents listed in Appendix C are key to understanding these Filing Requirements. Incentive Rate-setting applications filed by distributors must be consistent with the key references listed.*

- *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach - October 18, 2012*
- *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors - corrected December 4, 2013*
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities - December 11, 2009*
- *Guidelines for Electricity Distributors' Conservation and Demand Management - April 26, 2012 (2012 CDM Guidelines)*
- *Guidelines for Electricity Distributors' Conservation and Demand Management - December 19, 2014 (2014 CDM Guidelines)*
- *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module - September 18, 2014*
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - July 14, 2008*
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - September 17, 2008*
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - January 28, 2009*
- *Guideline (G-2008-0001) on Retail Transmission Service Rates - October 22, 2008 (Revision 3.0 June 22,2011 and any subsequent updates)*
- *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery - Final Disposition, December 15, 2011*
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) - July 31, 2009*

- *Chapter 5 - Filing Requirements for Electricity Transmission and Distribution Applications: Consolidated Distribution System Plan Filing Requirements - March 28, 2013*
- *Report of the Board on Transition to International Financial Reporting Standards (EB-2008-0408) - July 28, 2009*
- *Addendum to Report of the Board EB-2008-0408 - Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment - June 13, 2011*
- *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach - March 5, 2014*
- *Board Policy (EB-2012-0410) - A New Distribution Rate Design for Residential Electricity Customers - April 2, 2015*
- *Report of the Ontario Energy Board - Defining Ontario's Typical Electricity Customer – April 14, 2016*
- *Report of the Ontario Energy Board - New Policy Options for the Funding of Capital Investments: Supplemental Report – January 22, 2016*
- *Report of the Ontario Energy Board - Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs – May 19, 2016*

Additions for 2017:

- *Guidelines for Electricity Distributors' Conservation and Demand Management - December 19, 2014 (2014 CDM Guidelines) – Updated August 11, 2016*
- *Handbook for Utility Rate Applications – October 13, 2016*
- *Report of the Ontario Energy Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*
- *Guidance on Wholesale Market Service Accounting for Capacity Based Demand Response (CBDR) and new IESO Charge Type 9920 – March 29, 2016*
- *Guidance on the Disposition of Accounts 1588 and 1589 – May 23, 2017*

- *Updated Guidance on LRAM Variance Account 1568 – New Sub-Account 1568-0001 LRAMVA Demand Response – July 18, 2017*

# EP-3

# ATTACH 2

# The MAADs Handbook, otherwise known as the Handbook to Electricity Distributor and Transmitter Consolidations

# Issued January 19, 2016

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

# Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

## Table of Contents

# 1. Introduction

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

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

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

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

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

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

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

# 2. The OEB Authority and Review Process

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

## The OEB legislative authority

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

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

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

### The Application Review Process

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

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

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

## 3. The OEB Test

### The No Harm Test

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

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

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

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

## 4. The OEB Assessment of the Application

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

[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 <u>up to</u> 10 years. Distributors must select a definitive timeframe for the deferred rebasing period. This will allow the OEB to assess any proposed departure from this stated plan.

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

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

## Early Termination of Pre-Consolidation Rate-setting Term

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

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

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

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

## Early Termination or Extension of Selected Deferred Rebasing Period

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

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

## Rate Setting during Deferred Rebasing Period

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

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

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

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

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

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

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

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

## Off Ramp

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

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

## Earning Sharing Mechanism (ESM)

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

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

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

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

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

## Incremental Capital Investments during Deferred Rebasing Period

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

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

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

## Future Rate Structures

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

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

## Deferral and Variance Accounts

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

# INDEX: Schedule 1 – Relevant Sections of the OEB Act

**Section 86 of the OEB Act**

**Change in ownership or control of systems**

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

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

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

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

**Same**

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

**Acquisition of share control**

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

  (a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or

  (b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2).

# INDEX: Schedule 2 – Filing Requirements for Consolidation Applications

**INDEX: Schedule 2 – Filing Requirements for Consolidation Applications**

VT INCEPIT SIC PERMANET FIDELIS
Ontario

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

# Ontario Energy Board

## Filing Requirements
## For
## Consolidation Applications

**January 19, 2016**

# Table of Contents

# 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:
  - o Confirm that the ESM will be as required by the 2015 Report and the Handbook
  - o 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 –

# EP-3

# ATTACH 3

# THE OEB's Handbook for Utility Rate Applications Dated October 13, 2016

# Ontario Energy Board

**Commission de l'énergie de l'Ontario**

# Handbook for Utility Rate Applications

**October 13, 2016**

# 1. Table of Contents

# 1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates. Rates are the key revenue tool for regulated utilities. Under legislation, regulated natural gas utilities and electricity distributors, transmitters and Ontario Power Generation (OPG)[1] are only permitted to charge for their regulated services through an order issued by the OEB. In making an order, the OEB must set rates or payments that are just and reasonable.

This Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications. The Handbook is applicable to all rate regulated utilities[2], including electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. It has been developed based on the OEB's policies and the experience gained through the processing of rate applications since the release of the *Renewed Regulatory Framework for Electricity* (RRFE)[3]. The OEB expects utilities to file rate applications consistent with this Handbook unless a utility can demonstrate a strong rationale for departing from it.

The Handbook contains the following sections:

- Background on the Renewed Regulatory Framework
- Legislative Mandate and Test
- Rate Applications and the Adjudicative Process
- The OEB's Review of the Key Components of Rate Applications
- Rate-Setting Options
- Rate-Setting Policies

[1] OPG is the only generator subject to rate regulation by the OEB.
[2] This Handbook uses the term "utilities" to refer to all rate regulated entities unless specified otherwise.
[3] *Board Report: Renewed Regulatory Framework for Electricity Distributors,* October 18, 2012 (RRFE Report)

## 2. Background on the Renewed Regulatory Framework

The OEB established a new framework for electricity distribution rate regulation in 2012. The *Renewed Regulatory Framework for Electricity* is a foundational policy: it articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities. Key principles of the RRFE include the expectation for continuous improvement, robust integrated planning and asset management that paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

The OEB set out its goals for the RRFE as follows:

> The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.[4]

An important aspect of the RRFE is the evolution to an outcomes-based approach. The OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."[5] There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:

- Customer Focus: Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.

[4] RRFE Report, p. 1.
[5] RRFE Report, p. 2.

- Operational Effectiveness: Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

- Public Policy Responsiveness: Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First[6] in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low income customers through programs such as LEAP and/or OESP[7], or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement. Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program.

- Financial Performance: Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.

[6] Conservation First is a government policy referred to in the Long-Term Energy Plan.
[7] Low Income Energy Assistance Program (LEAP) and Ontario Electricity Support Program (OESP).

Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation).

Since the release of the RRFE Report, over half of Ontario electricity distributors have applied for rates under the RRFE. Enbridge Gas Distribution Inc. also applied using the principles of the RRFE. Based on its review of those rate applications, the OEB has now completed an assessment of the RRFE and the principles underpinning it. This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the *Renewed Regulatory Framework* (RRF) in this document and by the OEB going forward to reflect this transition.

# 3. Legislative Mandate and Test

The foundation for the OEB's public interest mandate is the *Ontario Energy Board Act, 1998*. The OEB Act sets out the objectives for the OEB's regulation of natural gas and electricity. The OEB balances these objectives in order to protect consumers, set demanding but fair performance expectations for utilities, facilitate the evolution of the sector, and support the policies of the Ontario government.

The OEB's authority to set rates for electricity distribution, transmission and payments for OPG[8] is set out in section 78 of the OEB Act. The key test is that the rates or payments must be "just and reasonable." The OEB reviews the information and proposals in a rate application in order to determine whether the proposals are reasonable for both consumers and the utility. For natural gas, the OEB's authority to set just and reasonable rates is in section 36 of the OEB Act.[9]

For all regulated utilities, the onus is on the utility to demonstrate that its rate (or payment amount) proposals are just and reasonable. If the OEB determines that the proposals are not just and reasonable, then it may set other rates (or payment amounts) which it determines are just and reasonable.

[8] For OPG, Ontario Regulation 53/05 also defines the OEB's authority.
[9] Details of the legislative provisions are set out at Appendix 1.

# 4. Rate Applications and the Adjudicative Process

This Handbook applies specifically to rate applications, under any of the legislative sections identified above, which are intended to set rates for a multi-year period (Custom IR), or for the first year of a multi-year period (Price Cap IR or Revenue Cap IR). Under the RRF there are a variety of incentive rate-setting (IR) options which are discussed further in section 6 (Rate-Setting Options).

A comprehensive rate application has three main components: the business plan (along with supporting documentation and reports), historical and forecast information, and rate models that show the derivation of specific proposed rates based on the data.

- Business plan: The utility's plan for its business is foundational to the proposals included in its rate application. This includes the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them. The OEB expects the business plan to be informed by the utility's engagement with customers. The business plan is supplemented and supported by the associated plans, reports and documentation (including system plans[10], capital and operational plans, programs, benchmarking, external reviews, and customer engagement activities) which form the core of the rate application. This utility business plan may differ from the corporate business plan that may include matters that go beyond the scope of the OEB's review in a rate application.

- Historical and forecast information: Information filed in support of a rate application facilitates a thorough review of the utility's proposals and ensures continuity in the regulation of each utility over time. The filing of this information does not mean that the OEB will approve every aspect of what is filed in a rate application. The OEB assesses the utility's plans, and the resultant costs and revenue requirement, in order to consider the benefits to customers and a fair return for utilities in setting just and reasonable rates.

[10] The term "system plan" is used in this Rate Handbook to refer generically to all types of plans that apply to the various sectors; that is "distribution system plan" for electricity and natural gas distributors, "transmission system plan" for electricity transmitters, and any nuclear and hydro-electric generation asset plan that OPG may file in the future.

- Rate models: The OEB has developed a set of rate models for electricity distributors which facilitates the review of rate applications and which distributors are required to use. These models are one of the tools the OEB uses to enhance the efficiency, consistency and accuracy of the review process.

To assist utilities, the OEB has developed filing requirements that identify the information that needs to be provided in an application. There are separate filing requirements for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. The OEB expects utilities to present rate applications that are complete and of high quality. A rate application is complete if it contains all of the information (data, reports and analysis) that the OEB has identified in the filing requirements. In addition to meeting the requirements from the filing requirements, high quality rate applications also address all of the regulatory policy considerations relevant to the company in a comprehensive, consistent and clear presentation that articulates the need for the utility's proposals and the value to customers.

In the past, the OEB used the regulatory process itself to augment a deficient application to ensure the information was complete and consistent. This approach added complexity and time to the process, increasing regulatory costs. In recent years, the OEB has conducted initial reviews of applications for completeness, to ensure that only applications which are substantially complete are allowed to proceed. A rate application must demonstrate on its face that it is of sufficient quality to support the OEB's rigorous review process. An application that does not meet this standard will not be processed; it will be returned for further work. This is one of the ways the OEB will ensure that utilities take full ownership of all aspects of the information and proposals included in their applications.

The OEB uses an open and transparent adjudicative process to review rate applications. The adjudicative process can involve a number of steps, depending on the type of application, to ensure that a utility's proposals are adequately examined and "tested" during the review. (Potential tools include interrogatories, technical and settlement conferences, and an oral hearing). The review involves stakeholders, including customer representatives and other groups. OEB staff ensures that the views of customers are considered in the application process by organizing community meetings to gather consumer views on the utility's proposals, using different media to notify customers that an application has been filed and facilitating the filing of letters of comment to the OEB from customers. The OEB is further augmenting its processes through the Consumer Engagement Framework to ensure customers have a stronger voice in the adjudicative process. The OEB uses the adjudicative process to ensure its review results in just and reasonable rates for customers. The OEB's approach to reviewing utility proposals within rate applications is discussed in the remaining sections of this Handbook.

# 5. The OEB's Review of the Key Components of Rate Applications

One of the OEB's primary goals is to ensure that utilities are delivering cost effective, efficient, reliable and responsive services to customers. The RRF is intended to elevate utility performance by creating incentives for superior performance. The RRF focuses on increased effectiveness and continuous improvement in meeting customer needs, including cost control and system reliability and quality objectives.

A utility's proposals are expected to demonstrate the alignment of the utility's strategic objectives with its current and future customers' expectations for reliable and reasonably priced service. The utility is expected to integrate its business challenges, and what its customers are saying, to create a compelling business plan that directly links to proposals included in the rate application and the four performance outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance. In reviewing utility proposals, the OEB will analyze past performance but is even more concerned with future performance. The Ontario energy sector has gone through significant change, and even more change is expected in the future, particularly technology-driven change which has the potential to deliver significant benefits to customers.

The OEB will use a variety of tools to aid its review work, including trend analysis, cost benefit analysis, reviews of distributor due diligence processes (planning, risk management, governance, etc.), benchmarking and other analytical tools. The OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility's spending proposals. If the OEB determines that a specific project or program has not been adequately justified, this may result in a reduction to the requested revenue requirement. It is the utility's responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements, within the funding provided through rates. This provides the utility with the responsibility and flexibility to meet its obligations in ways which benefit customers and the utility.

**In reviewing utility proposals in rate applications, the OEB's key considerations are:**

- **A focus on cost effective delivery of outcomes that matter to customers**
- **Robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risks**
- **Performance assessments which analyze the level of continuous improvement and a utility's ability to plan and execute plans**

The following key components are addressed in this section:

- Business plan
- Customer engagement
- Planning
- Outcomes and performance metrics
- Performance scorecards
- Benchmarking
- Operations, Maintenance and Administration (OM&A) and Compensation Expenses
- Bill Impacts
- Mergers, Acquisitions, Amalgamations and Divestitures (MAADs)
- Non-Regulated Activities and Affiliate Transactions

## Business Plan

A utility's business plan for its regulated activities is fundamental to the evaluation of the proposals in its rate application. The business plan (which is included in the Executive Summary of the application) should describe the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the rate application and the plan to meet them, and how customers will benefit. It forms the "story" that underpins the rate application as a whole and its constituent parts. The business plan should address the utility's circumstances and challenges, integrate its customers' expectations, set performance commitments, and demonstrate how the results will be achieved. This business plan is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews and customer engagement) which form the core of the rate application.

The business plan should demonstrate that the utility's goals are appropriately aligned with the needs and preferences of its customers and the objectives of the RRF, and that the utility is well positioned to deliver on its goals. This information will allow the OEB to understand the impacts of the business plan on key areas of the application such as customer service, system reliability, costs and customer bills.

**In reviewing a utility's proposals in a rate application, the OEB will consider whether the business plan demonstrates how the utility's objectives are:**

- **Translated into outcomes**
- **Relate to what is being sought in the application**
- **Align with the objectives of the RRF**
- **Align with customer preferences and expectations**

### Customer Engagement

Customer engagement is foundational to the RRF. Enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. Today's customers are more informed and more active participants in their energy services. They should have a say in shaping utility plans, particularly given the customer's role in conservation efforts and the customer-focused nature of future technological innovation. Customers should also help determine the pace of utility investment.

Each type of utility will have a variety of customers to include in engagement activities. For example, natural gas utilities have end-use customers and transportation customers. Electricity distributors have end-use customers, generators, and sometimes other embedded distributors. Electricity transmitters have customers which are distributors, generators, and large end-use customers. Ontario Power Generation has an indirect relationship with end-use customers. Although the types of customers vary, the principles presented here are applicable to all utilities. The OEB expects utilities to adapt these principles to their particular circumstances.

Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate those interests and preferences into their plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs. Existing processes and customer interactions should also inform the customer focus element of the utility's proposals. For example, reliability complaints could inform investment program priorities, such as targeting poor performing feeders for upgrades, or the use of smart grid technology to reduce the duration of outages.

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities. The application must also demonstrate how the utility has reflected customer input in the development of its plans. The OEB will evaluate whether the utility's application is reflective of, and appropriately informed by, customer needs, expectations and preferences and whether the utility is positioned to deliver on its plans in a way that will provide value to customers.

**In reviewing customer engagement, the OEB will consider:**

- **The forms of customer engagement used, their quality and effectiveness**
- **The quality of the utility's analysis of customer input**
- **Whether and how customer input has informed the utility's planning**
- **Whether and how the utility's plans deliver benefits which address customer needs and preferences**

The OEB is not specifying how customer engagement should be done or how customer feedback should be received. It can take many forms, and the OEB expects utilities to consider a range of approaches, using both existing and new processes. A customer satisfaction survey is a tool to gauge how a customer views the past performance of its utility, but it is not a tool that engages customers on future plans and therefore is not sufficient to meet the OEB's expectations for appropriate engagement to inform the utility's plans. Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity. The OEB will consider the adequacy of customer engagement in assessing whether it has been demonstrated that a proposal provides value to customers. If the OEB determines that customer engagement has not been adequate, then the OEB may conclude that a program or project is not adequately justified, in whole or in part, and this could result in a reduction to the requested revenue requirement.

### Planning

Robust planning is one of the foundations of the OEB's RRF. The utility's business plan sets the context for the proposals in a rate application (as part of the Executive Summary of the application). The utility's system plan is an important component of the application and complements and supports the specific capital and operational plans and programs, and the associated budgets, which form the utility's overall business plan.

A utility's core business in serving customers is asset management, and strong asset management is essential to delivering reliable and quality energy services that customers value. Strong planning will help drive operational effectiveness, and the utility system plan will be an important component of the utility's business plan which supports the rate application. The capital intensive nature of the energy sector and long life of most assets means that investment brings with it the likelihood of rising costs as aging and fully depreciated assets are replaced with new assets. Therefore it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates. Utilities are expected to develop plans that deliver lower cost solutions over the long-term through a Conservation First approach, integration with regional plans, and consideration of the evolution of the sector, including innovation and new technologies. Utilities are expected to engage customers and incorporate their expectations into their planning.

The OEB's comprehensive policies for electricity distributor system planning, and filing requirements are set out in *Chapter 5 of the Filing Requirements for Electricity Rate Applications*. The planning principles, as set out in the next section, are applicable to all rate-regulated utilities. However, other utilities (natural gas utilities, electricity transmitters, and OPG) would include different types of initiatives in their plans. For example, a natural gas utility would need to incorporate the cap and trade program in its system plan. The discussion below is presented in the context of electricity distribution system plans, but is intended to provide guidance to electricity transmitters, natural gas utilities, and OPG.

### *Electricity Distribution System Plans*

The OEB requires electricity distributors to file a distribution system plan (DSP) every five years, regardless of the rate-setting method chosen. The DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The asset management process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus. The asset management process needs to be informed by an asset condition assessment such as equipment testing results, maintenance and usage history, historical failures or system weaknesses. Information is also required on the consequences of the failure of assets (such as how many customers will be affected, the type of customers and the time to restore the system) to appropriately prioritize plans. The capital expenditure plan sets out and justifies a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance and operations expenditures.

A DSP must contain sufficient information to allow the OEB to assess whether and how a distributor has planned to deliver value to customers, how the plan supports the effective management of the assets, and how a distributor is seeking to control the costs and related rate impacts of proposed investments. The asset management plan underpinning the DSP should be directly linked to the proposed budget, to demonstrate that the proposed capital expenditures have been determined through the necessary optimization and prioritization process.

The OEB has consolidated, streamlined, and strengthened its planning policies into an integrated approach. Under this integrated approach, all network investments will be planned together, including network renewal and expansion, connection of renewable generation facilities, smart grid development and implementation, conservation, and investments arising from regional planning processes.

The DSP is expected to have the following characteristics:

- Consolidated and stand-alone (i.e. not presented through separate parts across an application)
- Includes all assets, both system assets and general plant
- Underpinned by an asset condition assessment
- Linked directly to the proposed budget
- Integrates considerations of conservation, smart grid, renewable generation connection, regional planning, and any relevant public policies
- Demonstrates how the utility has planned to deliver value to current and future customers
- Demonstrates how the plan supports the effective management of the assets
- Demonstrates how the plan is optimized (by considering alternatives, including different capital program options, maintenance or operating solutions, the use of conservation to defer investments, the use of new and emerging technologies, etc.) and how projects are prioritized and paced to recognize potential rate impacts

In a cost of service proceeding the OEB will consider the entire five year DSP as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the DSP. The OEB has established a policy for the funding of capital for electricity distributors on the Price Cap IR option.[11] Requests for funding under these mechanisms must meet all of the same requirements for capital spending

[11] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

as would be in a cost of service or Custom IR application. Any Incremental Capital Module that involves a significant increase to a capital budget may need to be supported by a DSP along with customer engagement analysis.

**In reviewing the utility system plan, the OEB will consider the following:**

- **Have the criteria outlined in Chapter 5 of the *Filing Requirements for Electricity Rate Applications* been addressed?**
- **Does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and corresponding capital and operational plans and budgets?**
- **How has the plan addressed the information and preferences gathered from the utility's customer engagement work?**
- **Does the plan deliver quantifiable benefits for customers?**
- **Does the plan support the achievement of the utility's identified outcomes, and the outcomes of the RRF (customer focus, operational effectiveness, public policy responsiveness, and financial performance)?**
- **Has the company controlled costs through optimization, prioritization and pacing?**
- **Has the plan appropriately integrated conservation, renewable generation connection, regional plans, smart grid, and any relevant public policies?**

### Outcomes and Performance Metrics

The RRF is an outcomes-based approach. A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes. These outcomes are linked to performance metrics, which will be used to show whether the outcomes have been achieved. Utilities are expected to consider cost trends, benchmarking of comparable utilities, and learnings from their customer engagement in setting outcomes and performance metrics.

Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives. The outcomes should be based on the utility's business plan and should identify outcomes at the key program level that flow directly from the cost proposals. The outcomes should demonstrate the value proposition for customers and/or public policy goals. Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers and not a line by line review of expenditures. The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing.

Performance metrics are generally quantitative measures which will be used to assess whether the outcomes have been achieved; however qualitative measures may also be considered. Performance metrics ensure that the outcomes are measurable. For the pole line example noted above, the outcome could be increased reliability for that particular feeder.

The OEB has established a set of performance metrics for electricity distributors through its Performance Scorecard. In a rate application, the electricity distributor must identify metrics for its identified outcomes, which will often be in addition to those scorecard measures.

Other utilities (natural gas utilities, electricity transmitters and OPG) should establish performance metrics which are directly linked to the identified outcomes related to their business plans. These performance metrics will generally be part of the set of performance measures the utility has proposed for a performance scorecard (discussed further in the next section).

**In reviewing a utility's proposed outcomes and performance metrics, the OEB's key considerations are:**

- **A focus on strategy and results, not activities**
- **The need to demonstrate continuous improvement**
- **Outcomes which are demonstrated to be of value to customers**
- **Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement**

### Performance Scorecards

Customers expect continuous improvement in the utility services delivered to them. Utilities must demonstrate their performance through effective and transparent reporting. As part of the RRF, the OEB has developed performance measures and standards for electricity distributors in four areas: customer focus, operational effectiveness, public policy responsiveness, and financial performance.[12] This Performance Scorecard brings greater transparency to utility performance and

[12] *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach*, March 5, 2014

enhances the ability to assess performance over time and to compare performance across utilities.

In its rate application, an electricity distributor should discuss its performance for each of the Performance Scorecard measures over the last five years, and explain the drivers for its performance. The OEB's review of a utility's proposals will consider the utility's past and target performance against the four RRF outcomes. The electricity distributor is also expected to discuss its plans for continuous improvement. It is expected to identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan.

All other utilities (natural gas utilities, electricity transmitters, and OPG) are expected to propose a scorecard (including the performance metrics linked to the proposed outcomes) to measure and monitor performance and, where appropriate, enable comparisons between utilities. The format should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. After the OEB has set approved scorecards for one or more electricity transmitters and natural gas utilities, those scorecards will provide additional guidance to other utilities filing applications. However, a utility is also encouraged to propose other performance categories and measures that it believes would be meaningful for its operations as an Ontario utility.

The proposed scorecard should include data for at least five years. A utility may propose measures for which five years of data is not yet available if it commits to collecting and reporting the data through the course of the plan. Furthermore, the lack of historical data should not be a barrier to the setting of new measures, especially if these are important to monitoring a utility's future performance e.g. a measure on system utilization could report on how a utility is managing its assets. The OEB may undertake further work to make enhancements to any scorecard proposed through an application as the OEB continues to develop its approach to performance assessment, and to maintain a level of consistency for scorecards between utilities.

***In reviewing the proposed performance scorecard, the OEB's key considerations are:***

- ***Whether the measures capture key factors of utility performance***
- ***Whether the scorecard enables assessments over time and appropriate comparisons with other utilities***
- ***Whether the utility has set reasonable targets for its performance metrics***

## Benchmarking

Benchmarking will be used by the OEB to review a utility's proposals, including at the program level[13]. Utilities are expected to provide benchmarking analysis which supports their proposed plans and programs and demonstrates continuous improvement.

The OEB currently conducts total cost benchmarking for electricity distributors. An econometric model is used to generate efficiency rankings and assign electricity distributors to one of five groups based on their total cost performance, including both capital and OM&A costs. These results are used to set the productivity stretch factors for the incentive rate-setting mechanism (IRM) applications, and will also be a consideration in assessing a utility's cost trend performance. An electricity distributor is expected to provide a forecast of its efficiency assessment using the model for the test year. This provides the OEB with a directional indicator of efficiency.

Utilities are generally not required to present total cost benchmarking analysis as part of their applications, unless they have been ordered to do so through an OEB decision. Two other types of benchmarking are required in rate applications:

- External benchmarking to analyze specific measures or specific programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group
- Internal benchmarking to assess continuous improvement by the utility over time

Benchmarking need not be limited to unit cost benchmarking (e.g. the capital cost of a billing system per customer or the cost of cable or pipe per km). Performance benchmarking in areas such as reliability or other outcomes may also be appropriate. What is important is that the utility explains how it has interpreted the benchmarking and what actions it has taken as a result of it.

With the Custom IR rate setting options, a utility can customize the rate setting mechanism for their specific circumstances. Given this flexibility, the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term. When determining what areas to benchmark, a utility should consider the following potential criteria:

[13] Such as cost per pole replacement or billing costs per customer

- Key areas where the utility's performance is considered particularly strong or particularly weak
- Areas where expenditures are a key driver for the revenue requirement
- Areas that have been targeted for specific programs
- Areas where the OEB has expressed concern in past decisions
- Areas related to performance metrics and/or performance scorecard measures
- Linkages to customer engagement analysis

Utilities are expected to present objective, well researched benchmarking information, supported by a high quality and thorough analysis (using either third party or internal resources) that can be rigorously tested.

**In reviewing benchmarking, the OEB will consider:**

- **The structure of the benchmarking and the comparators used**
- **The quality of the benchmarking**
- **The linkages between the results of the benchmarking and the proposals in the rate application**

### OM&A and Compensation Expenses

Under the RRF, the OEB has adopted an outcomes-based approach to regulation. As a result, the review of OM&A expenses will focus on the examination of outputs and programs, and whether there is evidence of continuous improvement, rather than the discrete line items or inputs to the OM&A budgets.

In addition, because employee compensation costs are already reflected in the proposed capital and operational programs, a detailed presentation of compensation is not necessary for the OEB's consideration of the proposed program costs to achieve the expected outcomes. The OEB does expect a utility to provide a description of its compensation strategies and policies (e.g. how salary scales are set and reviewed, how target salaries are compared to external benchmarks, performance pay structures, and the board of directors oversight process) and to clearly explain the reasons for all material changes to head count and compensation, and the outcomes expected from these changes. A utility should demonstrate clearly the linkages between its compensation strategies and policies and utility performance. Additional requirements for particular utilities may also arise from specific OEB directions in prior proceedings.

**In reviewing a utility's proposed expenses for OM&A and Compensation, the OEB's key considerations are:**

- **Have the costs been paced at the rate of inflation, and if not, what is the rationale for increased costs**
- **If the rationale for increased costs is customer or load growth, what is the relationship between increased costs and that growth**
- **A focus on strategy and results, not activities**
- **The need to demonstrate sustainable continuous improvement**
- **The outcomes that are expected from the proposed expenses**

### Bill Impacts

The OEB is sensitive to customer concerns about energy bills. Customers are entitled to reliable service at reasonable rates. The OEB has adopted a number of policies to drive further efficiencies and to ensure utilities are focussed on providing value to customers. Customer needs and expectations, the pacing and prioritization of investment, and utility performance over time and in comparison to peers are all factors that the OEB considers, and are intended to drive effectiveness and continuous improvement. Utility proposals and plans ultimately translate into customer rates and bills. Rate changes and bill impacts are a particular focus of customers, and of the OEB. The OEB will hold utilities accountable to justify the bill impacts of their proposals; effective cost control will be expected.

Importantly, each utility can choose the rate-setting approach that best suits its particular needs. A utility is expected to tailor its proposals to meet the requirements of increased investment along with the requirements for enhanced productivity, cost control, and continuous improvement to create an appropriate rate profile.

**In reviewing proposals in rate applications, the OEB will assess:**

- **How the utility has considered total bill impacts in its planning**
- **How the utility has demonstrated the responsiveness of its expenditure plans to the need for stable and reasonable rates for customers**
- **Whether the pacing and prioritization of planned work is appropriate in light of the bill impacts of carrying out necessary investments**
- **What the bill impacts are for only those components of the bill that are within the control of the utility (no pass-through items)**
- **Whether any mitigation is warranted**

### Mergers, Acquisition, Amalgamations and Divestitures (MAADs)

The OEB has issued a *Handbook to Electricity Distributor and Transmitter Consolidations*[14] that makes clear that rate setting is generally not a consideration in reviewing a consolidation through a merger, acquisition, amalgamation or divestiture. In the first cost of service or Custom IR application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction, including a rate harmonization plan and/or customer rate classifications post consolidation.

**This will include consideration of:**

- **The treatment of any premium above book value paid as part of a consolidation (no premium is to be recovered from customers).**
- **The savings that have been generated through the consolidation.**
- **Whether there were any inducements or incentives beyond the purchase price to encourage a shareholder to agree to the consolidation and if so whether there is any intent to recover the costs of those inducements or incentives from customers. Any costs incurred will be reviewed to ensure that the costs incurred are delivering the best value to customers.**
- **Whether the rate harmonization plan includes a detailed explanation and justification for the implementation plan, and an impact analysis. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. Regardless of the option adopted, the OEB will assess whether the proposed harmonized rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.**

### Non-Regulated Activities and Affiliate Transactions

As noted previously, the business plan filed with the rate application is not necessarily the corporate business plan for the utility. There may be aspects of the corporate business plan that are not relevant to the OEB's review of a rate application. The OEB will consider non-regulated activities and transactions with affiliates in the context of their effect on the regulated rates to customers to ensure there are no cross subsidies that negatively affect these regulated customers.

[14] January 19, 2016

**Depending on the corporate structure of the utility, this could include an assessment of:**

- **The reasonableness of the costs allocated to non-regulated activities within the regulated utility**
- **The costs to be charged to the regulated utility from an affiliate**
- **The revenues forecast to be received from an affiliate for services provided by the regulated utility**
- **Whether these activities affect the quality of services to be delivered to the customers of the regulated utility**
- **Whether non-regulated activities will affect the financial viability of the regulated utility, or introduce a significant enough risk that it affects debt financing costs**

# 6. Rate-Setting Options

The OEB's approach to rate regulation has evolved over time to create better incentives to drive utilities to improve their efficiency in a way that benefits both customers and shareholders. Performance-based regulation under the RRF is the framework for rate-setting. This is consistent with broader trends amongst regulators around the world to shift rate regulation from a process of simply recovering costs to one of driving improved utility performance through incentives.

The OEB has developed a set of rate-setting options[15] to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. Each of the methods also includes incentives and benefits for customers related to continuous improvement and productivity.

### Electricity Distributors

To support the move to an outcomes based approach, the OEB recognized the need to provide flexibility in rate setting options to give utilities the necessary tools to develop business plans that meet their needs. The RRFE established three incentive rate-setting (IR) methodologies for electricity distributors: Price Cap IR (previously known as 4th Generation IR), Custom IR, and the Annual IR Index.

- Price Cap IR: Under this methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula specific to each year. For electricity distributors, the formula includes an industry-specific inflation factor and two factors for productivity. One productivity factor is a fixed amount for industry-wide productivity and the other is a stretch factor, which is set each year based on the level of productivity the electricity distributor has achieved.

[15] There are rate setting options under the RRF that take into consideration actual or forecast costs, including both cost of service and custom incentive rate-setting; also called rebasing applications. Other rate-setting options, such as revenue cap and price cap incentive rate-setting, decouple the rates from costs.

- Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.

- Annual IR Index: Under this methodology, rates are subject to the same annual adjustment formula as those under Price Cap IR. Utilities under the Annual IR Index are not required to periodically set base rates using a cost of service process, but they are required to apply the highest stretch factor. This approach is the most mechanistic of all rate applications. These utilities are required to provide five-year distribution system plans as a reporting requirement every five years, and like all other distributors will continue to report their performance using the OEB's Performance Scorecard. This will allow the OEB to determine whether the planning process and level of investment is adequate and whether service levels remain appropriate.

Electricity distributors may choose from any of these three methodologies. There are no eligibility requirements for any of these methods, but the rate application must meet the requirements of the rate-setting option. Those requirements are set out in the OEB's RRFE Report, in the filing requirements and in this Handbook.

### Electricity Transmitters

Electricity transmitters may choose either Custom IR or a Revenue Cap IR. The Revenue Cap IR methodology is similar to the Price Cap IR option discussed previously for distributors. Individual rates are not set for each transmitter. The revenue requirement for each transmitter is approved by the OEB and this is used to set uniform transmission rates that apply throughout the province. Therefore, instead of a Price Cap IR option, a transmitter can propose an incentive mechanism for adjusting its revenue requirement in a similar manner.[16]

[16] As set out in Chapter 2 of the *Filing Requirements for Electricity Transmitter Applications*, electricity transmitters will be permitted a final cost of service proceeding as a transition mechanism, and that proceeding will incorporate certain elements and principles of the RRF (including customer engagement, benchmarking, and a transmission system plan).

### Natural Gas Utilities

Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

### Ontario Power Generation

The OEB established expectations that payments for OPG will be based on Price Cap IR for the hydroelectric business and Custom IR, based on the RRFE principles, for the nuclear business. The OEB may set out its expectations for future applications in its next decision and order for OPG.

### Specific Considerations for Custom Incentive Rate setting

The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended. A Custom IR application is by its very nature custom, and therefore no specific filing requirements have been established. However, any utility filing a Custom IR application should be informed by the cost of service filing requirements and this Handbook. The sections that follow set out the OEB's minimum standards for certain key elements of Custom IR applications.

There is no threshold test or eligibility requirement for a Custom IR application. The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards:

- Term: A Custom IR must have a minimum term of five years. The OEB has determined that this term supports a longer term approach to planning to smooth expenditures and pace rate increases, strengthens efficiency incentives and supports innovation. Longer terms can be proposed with appropriate mechanisms for consumer protection as discussed below.

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed below) and earnings sharing but could include other approaches specific to a utility's circumstances.

For electricity distributors, the OEB has established an off-ramp that involves a threshold above the distributor's approved return on equity at which a regulatory review may be triggered.[17] An electricity distributor can propose an alternative threshold that provides greater protection for customers. Other utilities may propose an off-ramp that takes into consideration the OEB's objective of protecting customers from excess earnings.

The OEB does not require a Custom IR to include an earnings sharing mechanism, except in the context of deferred rebasing periods as part of electricity distributor consolidation[18]. While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred. The requirement for a custom index ensures that benefits are shared immediately with customers through productivity commitments.

If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

If a Custom IR application does not meet all of these requirements, the OEB may impose a reduced term, reject the application or determine that an application is incomplete and will not be processed until the requirements are met.

[17] This policy was reaffirmed in the RRFE Report.

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

# 7. Rate-setting Policies

The OEB has a number of accounting and rate-setting policies that are applicable to rate applications. Appendix 3 includes summaries of these policies. The OEB expects to update this appendix as more policies are developed. Utilities and stakeholders should consult the relevant policy documents (which are available on the OEB website) for detailed information.

# Appendix 1: Excerpts from the *Ontario Energy Board Act, 1998*

This appendix sets out the key legislative provisions related to rate setting for natural gas and electricity.

## *Statutory Objectives*

### Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

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.

### Board objectives, gas

2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.
4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

## *Natural Gas Rate Setting*

### Order of Board required

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

### Order re: rates

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.

### Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

### Burden of proof

(6) Subject to subsection (7), in an application with respect to rates for the sale, transmission, distribution or storage of gas, the burden of proof is on the applicant.

## *Electricity Distribution and Transmission Rate Setting*

### Orders by Board, electricity rates

### Order re: transmission of electricity

78. (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.

### Order re: distribution of electricity

(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract.

### Rates

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.

### Burden of proof

(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.

## *Ontario Power Generation Payment Setting*

### Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations.

### Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect.

### Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

### Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. .

### Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section.

# Appendix 2: Glossary of Terms

### Advanced Capital Module
The Advanced Capital Module (ACM) is an evolution of the Incremental Capital Module (see below). The ACM improves the regulatory efficiency for the review and approval of proposed incremental capital expenditures. An ACM proposal is made during a cost of service application to identify, based on the 5-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth. Reviewing ACM projects as part of a cost of service application allows for testing of the need, pacing and prioritization of projects as part of the more comprehensive review that occurs in processing a cost of service application. However, rate riders to fund ACM projects only come into service when the assets enter service during the IRM period.

### Annual Index Rate-setting
The Annual Index Rate-setting method is a variation on the Price Cap IR method that is suitable to utilities with very stable investment expectations; these will typically be experiencing little growth and where investments are largely stable and to replace existing assets at end-of-life. A utility under the AIR has rates adjusted by the Price Cap IR method, but where the stretch factor is set at the highest amount. However, a utility under the AIR does not have to periodically rebase rates through a comprehensive cost of service review unless and until its circumstances change.

### Capital Expenditures
Capital expenditures are amounts spent by a utility to acquire or enhance fixed assets, such as land, buildings, and major equipment. When the asset is ready to be used, the expenditure is added to rate base as a capital addition. The expenditure is then recovered through rates over the life of the asset.

### Capitalization Policy
Capitalization policy is the accounting policy used to determine whether money spent in a given year should be treated as a capital expenditure or as an operating, maintenance and administrative expense. If the amount is determined to be part of capital expenditures, then the amount is added to rate base (capitalized) and recovered gradually over time.

### Conditions of Service

Electricity and natural gas distributors are required by the OEB to describe their customer-facing operating practices in a Conditions of Service document. This document includes topics such as connection policies, security deposits, and opening or closing accounts. Each distributor must ensure that its Conditions of Service is public and readily available to customers.

### Conservation and Demand Management

Activities and programs which are designed to reduce electricity use are known as Conservation and Demand Management, or CDM.

### Cost Allocation

Cost allocation is the process of dividing a utility's total costs amongst different customer classes as fairly as possible. The objective is to allocate costs in a way that reflects how each customer class uses the utility's services. Once the costs are allocated to each customer class, the rates are set to recover those costs.

### Cost of Capital

The cost of capital is the cost associated with the debt and equity which are used to finance a utility's business. The OEB sets the level of debt and equity in the capital structure. The OEB also sets the cost of debt (long-term and short-term) and the return on equity, based on market conditions and the risks utilities face. The cost of capital is included in rates, but a utility could earn a higher or lower return on equity, depending upon its performance.

### Cost of Service

Cost of service is the total cost for a utility to provide service to its customers. A cost of service application is a detailed presentation of a utility's costs. The OEB reviews a cost of service application and decides the rates that a utility will charge its customers. The OEB examines the utility's operating, maintenance and administrative expenses and capital expenditures, as well as the expected number of customers and total amount of energy delivered. The cost of service does not include the commodity costs of the energy (natural gas or electricity); those costs are treated separately.

### Customer Class

A customer class is a group of customers who use a similar amount of energy, or use energy in a similar way (for example, residential customers). A utility's total costs are divided among the customer classes to set rates. The cost to serve each customer in a particular class is similar, and therefore it is fair for all customers in a class to pay the same rate.

## Custom Incentive Rate-setting (Custom IR)

While the Price Cap IR option, along with options such as ICMs and ACMs should be adequate for most utilities, some utilities may find that their circumstances, such as high growth or significant capital investments, may not be accommodated adequately through the standard approach. Utilities with significant operating and capital expenditure needs may apply for a multi-year (minimum five years) Custom IR plan where rates are set for all years of the plan term.

## Deferral and Variance Accounts

Variance accounts track the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower, then the extra money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the extra amount through future rates. A deferral account tracks the cost of a project or program which the utility could not forecast when the rates were set. When the costs are known, the utility can then request permission to recover the costs in future rates.

## Demand Meter

A demand meter measures the maximum amount of electricity used in a set period of time, for example 15 minutes. The largest commercial and industrial customers have demand meters.

## Demand Side Management

Activities and programs which are designed to reduce natural gas use are known as Demand Side Management or DSM.

## Depreciation and Amortization

Depreciation and amortization are standard accounting practices. Depreciation is applied to tangible assets, like buildings, poles and computers, as a way to recover the cost of the asset gradually. Over the lifetime of a tangible asset, a portion of the total cost is treated as depreciation expense each year and recovered through rates. Amortization is like depreciation, but it is used to recover the costs of intangible assets like licences and goodwill.

## Distribution - Electricity

Distribution is the final stage in the delivery of electricity from generators to customers. Distributors take electricity from the high voltage transmission system and convert it to lower voltages (below 50kV). Distributors then use equipment such as lines, poles, and meters to deliver the electricity to customers. The OEB licenses and sets the rates of electricity distributors.

### Distribution – Natural Gas

Distribution is the final stage in the delivery of natural gas from producers to customers. Distributors take natural gas from the high pressure transportation system and reduce the pressure. Distributors then use equipment such as pipelines, compressors and meters to deliver natural gas to customers. The OEB sets the rates of natural gas distributors.

### Distribution Rates

Distribution rates are the charges that recover a distributor's own costs of providing distribution service, including operations, maintenance and administrative expense, depreciation, taxes, interest, and return on equity. A distribution rate typically includes a monthly fixed charge and a volumetric rate (a cost per unit of electricity used). The OEB approves the rates that a distributor can charge.

### Feed-in Tariff (FIT)

Feed-in Tariff (FIT) is an Ontario government program offered to encourage development of renewable energy generation. Wind, water, biomass, biogas, landfill gas and solar generators are eligible for the FIT program. FIT participants enter into a long-term contract to sell electricity to the province at a guaranteed fixed price. The price is designed to cover project costs including a return on the investment.

### Generation

Generation is the production of electricity from a fuel source. In Ontario, most electricity is generated at nuclear, hydroelectric, natural gas, wind, solar, and biomass facilities. Generation facilities are connected to the Ontario grid which delivers electricity to customers. Some generators are connected to the high voltage transmission system; others, typically smaller ones, are connected to the lower-voltage distribution system.

### Incentive Regulation

The OEB sets rates using incentive regulation. Incentive regulation is a set of tools or methods which encourage utilities to become more efficient in ways that will benefit customers through better service and lower rate increases. The shareholders of the utilities also have the opportunity to benefit from efficiency improvements through higher earnings.

### Incremental Capital Module

The Incremental Capital Module (ICM) is a capital tracker mechanism which allows for funding of significant capital investments for discreet projects during the period of incentive regulation between cost of service applications to rebase rates. Any qualifying ICM capital project must satisfy a materiality threshold to determine that the incremental capital amounts are beyond the normal level of capital expenditures expected to be funded by rates, including the effect of customer and load growth. An ICM request is requested and approved as part of a Price Cap IR application.

### Interval Meter

An interval meter measures electricity use and transmits the data at regular intervals, for example each hour. Mid-size commercial and industrial customers have interval meters.

### Licensed service territory

An electricity distributor's licensed service territory is the area in which the distributor has exclusive authority to distribute electricity. Every electricity distributor in Ontario must be licensed by OEB, and the licence identifies the service territory. For example, Toronto Hydro-Electric System Limited is licensed to distribute electricity within the City of Toronto.

### Loss Factor - Electricity

A small amount of electricity is used up through the process of moving electricity from generators to customers. A loss factor is an adjustment to rates to recover the cost of this electricity which is consumed during delivery. The loss factor is approved by the OEB.

### Meter

A meter measures natural gas or electricity use, and the data is used to bill customers. A standard meter measures the amount of electricity or natural gas consumed on a cumulative basis. These meters are read periodically, for example bi-monthly.

### MicroFIT

MicroFIT projects are very small renewable electricity generation projects, with capacity under 10 kilowatts. An example of a microFIT project is a rooftop solar installation on an individual house. The owner of the microFIT project is paid a fixed price for each unit of electricity generated during the contract period (typically 20 years). MicroFIT is part of the Feed-in Tariff (FIT) program which includes larger renewable electricity generation projects (see definition of Feed-in Tariff).

### Monthly Service Charge

The monthly service charge is a fixed amount each month, regardless of usage. This charge is designed to recover the fixed costs of providing distribution services which do not vary with usage. Meters, poles, and wires are some examples of fixed costs. The monthly service charge is one part of a customer's total bill; other parts of the bill may vary with usage.

### Operating, Maintenance and Administrative Expenses

Operating, maintenance and administrative expenses are the costs associated with running a utility on a day to day basis. Examples of these costs include employee salaries, tools and equipment, and office expenses. Operating, maintenance and administrative expenses do not include costs associated with investment in assets, such as depreciation or interest payments.

### Payments in Lieu of Taxes (PILs)

Most Ontario electricity transmitters and distributors do not pay Canadian corporate income tax. Instead, they make payments in lieu of taxes (PILs) to the Ontario government. PILs are calculated in the same way as corporate income taxes and are recovered through rates.

### Price Cap

Price cap refers to the mathematical formula used to set how much a utility's rates can increase in a year when the utility is not having a full review of its rates. The formula ensures that a utility's rates will increase at a rate which is less than inflation. For most electricity distributors, rates are set for one year using a full review, and are then set for four years using a price cap formula.

### Price Cap Incentive Rate-Setting

The Price Cap Incentive Rate-setting (Price Cap IR) is the standard formulaic method by which distribution rates are annually adjusted during the incentive rate-setting period between cost of service applications. The formula adjusts current rates for the following year by inflation in input prices (costs of production or service) less expected productivity improvements including a stretch factor (or consumer productivity dividend). The Price Cap IR is the standard rate-setting method for most electricity distributors between cost of service applications.

### Rate Adder

A rate adder is an amount added to the base rate to provide advance funding for a special project which has been mandated by the OEB. When the project is completed and the final cost is approved by the OEB, the money collected through the adder will be deducted from the total cost. This adjusted total cost will then be recovered or refunded over time through rates.

### Rate Base

Rate base is the total dollar value of all the assets used by a utility to provide energy service: wires, poles, meters, IT equipment, etc.

### Rate Rider

A rate rider is an amount which is added to or subtracted from the distribution rate to recover or refund a specific amount of money for a temporary period, generally a year or less. Once the period ends, the rate rider stops.

### Revenue Requirement

The revenue requirement is the total cost for a utility to provide energy service. It includes the cost of salaries, equipment, capital projects, depreciation, taxes, interest and a return on the equity invested by shareholders. The revenue requirement is used to set rates for customers.

### Revenue Sufficiency/Deficiency

The revenue sufficiency or deficiency is the total amount by which a utility's revenue needs to decrease or increase from the current level to earn the revenue requirement. When the OEB sets new rates for a company, it compares the total revenue the company would earn using the current rates to the total revenue the company is entitled to earn. If there is a revenue sufficiency, it means the company would recover too much revenue under the current rates, and therefore rates need to be reduced. If there is a revenue deficiency, it means the company would not recover enough revenue under the current rates, and therefore rates need to be increased.

### Revenue-to-Cost Ratio

The revenue-to-cost ratio is the relationship between the revenues from a particular customer class and the costs to serve that customer class. The ratio can be expressed as a decimal value, such as 0.90, or given as an equivalent percent value, such as 90%. For this example, a 90% revenue-to-cost ratio would mean that the customer class is paying 90% of the costs that the distributor incurs to serve that class. The revenue-to-cost ratio is one of the factors the OEB considers when setting rates. The goal is to have each class pay for the costs of serving it.

### Service Reliability

Service reliability refers to the level of continuous service a utility provides without interruption or an outage. The OEB sets measures and standards which track the type and duration of outages for each utility.

### Service Quality Indicators

Service quality indicators measure the level of customer service a utility provides. Examples of service quality indicators include meeting scheduled appointments, billing accuracy, and telephone response time. The OEB sets standards for key service quality indicators and monitors performance. Service quality indicators are not related to the number or duration of power outages (see definition for service reliability).

### Smart Grid

The smart grid uses advanced information technology to improve communication to and from individual parts of the electricity system. The smart grid constantly monitors the system, making it more efficient. It can also detect and fix problems more quickly, thereby increasing reliability.

### Smart Meter

A smart meter measures electricity consumption continuously, and transmits the data electronically. This data is used to charge for electricity according to the time of day (time-of-use rates). Residential and small commercial customers in Ontario have smart meters.

### Specific Service Charges

Specific service charges are for certain extra services such as special meter reads, late payment interest, and legal letters. Each specific service charge is based on the cost to provide the service and is only charged if a customer uses the service. The costs to provide these services are not included in distribution rates, but they still must be approved by the OEB.

### Tariff of Rates and Charges

The Tariff of Rates and Charges is a public document that lists the OEB-approved rates and charges for utility service. Utilities must use these rates and charges to bill their customers. Rates are listed for each customer class, along with other charges for a variety of specific services.

### Transformer

A transformer is the equipment used to change the voltage of electricity. Most customers use electricity at low voltage, but electricity is transmitted over long distances at high voltage because it is more efficient. A transformer is used to reduce voltage before it is delivered to customers. A transformer can also be used to increase voltage, for example where an electricity generator is connected to the transmission system.

### Transmission - Electricity

Transmission is an intermediate step in the delivery of electricity from generators to customers. Transmitters take electricity from generators and transmit it via high voltage transmission lines to distributors, where it is converted to lower voltages and provided to customers. The OEB licenses and sets the rates of electricity transmitters.

### Transportation – Natural Gas

Transportation is the intermediate stage in the delivery of natural gas from producers to customers. Transporters take natural gas from the producers and transport it in high pressure pipelines to natural gas distributors who then deliver it to customers at lower pressures. The OEB sets the natural gas transportation rates for companies that operate only in Ontario.

### Unmetered scattered load

Unmetered scattered load is a class of customers that use small amounts of electricity but have no meter. Examples include traffic lights, bill boards, bus shelters, and railway crossings. Rates for these customers are set on the basis of estimated consumption.

### Volumetric Rate

A volumetric rate is a rate applied to each unit of electricity or gas that a customer uses. As a result, the more energy a customer uses, the higher the total charge. Some parts of the customer's bill are based on volumetric rates, for example the Electricity line. Other parts of the bill are fixed no matter how much energy is used.

### Weather Normalization

Weather normalization is a mathematical adjustment to past energy usage data. This adjustment removes the impact of annual variations in weather to show what the usage would have been under normal (or long term trend) weather conditions. Utilities weather normalize data to better understand how other variables, such as energy efficiency, price, building structures and new technology impact demand. This helps utilities understand trends in energy consumption and develop more reliable forecasts.

### Working Capital Allowance

The working capital allowance is the cash a utility needs in order to pay its operating, maintenance and administrative expenses during the time between when the utility spends money to provide service and when it receives payment from its customers. The working capital allowance is included in a utility's rate base.

# Appendix 3: Rate-setting Policies

### Accounting Standards

Utilities will use International Financial Reporting Standard (IFRS) as the basis for their regulatory accounting unless the OEB has approved another standard or the utility is eligible for Accounting Standards for Private Enterprises (ASPE)[19]. If an accounting standard other than IFRS is used and if the accounting standard relies on the approval of a regulator for the determination of certain costs (for example, capitalization of costs), then this must be disclosed to the OEB in the rate application.

### Capital Funding Options

During the IRM period, it is expected that a utility should manage both its capital and operating expenses to service current and new customers while maintaining its financial viability and delivering productivity improvements, in line with the "inflation less productivity" Price Cap IR adjustment. However, capital investments can be "lumpy". To preserve the efficiency of the IRM process and avoid early rebasing or inefficiently timed capital investments aligned with the cost of service rebasing application, the OEB has provided for capital tracker mechanisms (e.g. the Incremental Capital Module and the Advanced Capital Module developed for electricity distributors). These allow for approval and funding recovery of qualifying capital investments during the IRM period between cost of service rebasing where material capital investments that are beyond what is normally funded through rates can be reviewed and approved without requiring an early rebasing. The ICM was established in 2008 as part of the 3rd Generation IRM, but it and the ACM have evolved as a result of the OEB's review. The OEB's policies on the ICM and ACM are documented in two OEB reports.[20]

### Natural Gas Demand Side Management (DSM) Costs

Natural gas distributors may apply to the OEB for funding to support the design and delivery of broad-based DSM plans. The OEB's policy document for gas utility DSM plans (the DSM Framework[21]) provides the basis for any application that seeks approval of amounts related to DSM programs. Natural gas distributor DSM plans are made up of individual programs for certain customers and are aimed to reduce overall natural gas

[19] *Report of the Board: Transition to International Financial Reporting Standards*, July 28, 2009 and *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011.

[20] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

[21] EB-2014-0134

consumption and increase the efficiency of equipment and technologies that use natural gas. OEB-approved DSM funding, which is used to support program design, delivery, implementation, marketing and administration, is approved by the OEB under Section 36 and is recovered by the gas utility from its customers through distribution rates.

### Electricity Conservation and Demand Management (CDM) Costs

Electricity distributors may apply to the OEB for CDM funding for the purpose of deferring the capital investment for specific distribution infrastructure. The OEB's policy document for electricity distributor CDM (the CDM Requirement Guidelines[22]) provides guidance for electricity distributors seeking approval of any such proposal. Electricity distributors may pursue activities such as electricity conservation and energy efficiency programs, demand response programs, energy storage programs and programs aimed at reducing distribution losses. The primary goal of these activities must be for the purpose of deferring the capital investment for specific distribution infrastructure. Any OEB-approved funding is provided under Section 78 and is recovered by the electricity distributor from its customers through distribution rates. For all other CDM related programs, including general customer-focused electricity conservation and energy efficiency programs, electricity distributors must enter into contractual agreements with the IESO. These programs are not funded through distribution rates

### Cost Allocation

Cost allocation is the process used to determine how a distributor's total revenue requirement will be attributed to each customer class. The guiding objective is to allocate costs to the customers that cause the costs to be incurred. Although highly technical in nature, cost allocation also requires significant judgement.

The OEB's cost allocation policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors.[23] The OEB has established principles and approaches which address many of the issues which arise during the cost allocation process. Electricity distributors are encouraged to include cost allocation proposals which conform to the OEB's established policies. An electricity distributor (or any other party to a proceeding) may propose an alternative approach, but must provide sufficient evidence and analysis to support a determination that the alternative is a superior approach in the circumstances.

[22] EB-2014-0278

[23] *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*, March 31, 2011.

Natural gas utilities, electricity transmitters, and OPG should support their cost allocation proposals with appropriate rationale, based on the OEB's historical approach to cost allocation issues for these utilities. Natural gas utilities, where applicable, must provide information on its regulated and unregulated storage operations and a description of the allocation of costs between regulated and unregulated storage.

### Cost of Capital

Utilities have the opportunity to recover their cost of capital through their rates. The OEB sets the cost of capital using a formula-based approach, which has streamlined the regulatory process considerably.[24] The same approach is used for all utilities, and the results are predictable, stable and fully transparent. The general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically 5-years.

A utility applying for cost of capital under the OEB's policy is not required to provide supporting evidence for its return on equity proposal. The onus is on other parties to provide evidence to demonstrate that the policy should not apply. Support must be provided for debt costs proposals. A utility (or any other party to a proceeding) may propose alternative approaches, but must provide sufficient evidence and analysis to support a determination that the alternative is appropriate in light of the utility's circumstances.

### Depreciation

Depreciation is the return of invested capital over the useful lives of these assets. Depreciation is a significant component of a utility's revenue requirement. While the calculation of depreciation expense can be a relatively mechanistic exercise resulting from assets in service and forecast to be in service, it relies on an appropriate study of the useful lives and componentization of the utility's assets[25]. This study will form an important supplementary part of the utility system plan. A utility can use a third-party for its depreciation study, but is not required to do so unless ordered by the OEB.

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[24] *Report of the Board on the Cost of Capital for Ontario`s Regulated Utilities,* December 11, 2009 and OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016 and associated OEB cover letter.

[25] Information that the OEB expects electricity distributors to consider is contained in the OEB's letter regarding *Depreciation Study for Use by Electricity Distributors, Consultant Final Report EB-2010-0178 – Transition to International Financial Reporting Standards* and the associated report by Kinectrics Inc. titled Asset Depreciation Study for the Ontario Energy Board, July 8, 2010 and the OEB's letter regarding *Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013,* July 17, 2012.

Regardless of how the work is completed, the study must be supported by high quality evidence and a thorough analysis that can be rigorously tested.

### Natural Gas System Expansion

The OEB has issued specific guidelines for natural gas utilities' transmission and distribution system projects. The OEB's *Report on the Expansion of Natural Gas System in Ontario*, the E.B.O. 134 Report, forms the basis of the filing requirements on the economic feasibility tests to be applied to leave to construct applications for pipeline transmission projects. A natural gas utility must provide information of transmission projects in its capital plan and provide an assessment of the potential impacts of the proposed natural gas pipeline(s) on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of costs, rates, reliability and access to supplies.

The OEB issued its *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188) in January 1998. This report provides the criteria under which the OEB assesses the overall economic feasibility of distribution system expansion projects. A key principle of the guidelines is that existing ratepayers should be held harmless from rate impacts resulting from the cost of new connections. A utility as part of its capital plan must provide an assessment of all its distribution system expansion projects as per the *E.B.O. 188 Guidelines* and demonstrate that existing customers will be held harmless from the proposed distribution system expansion projects. This policy is currently under review by the OEB under proceeding EB-2016-0004.

### Rate Design

Once costs are allocated to a particular customer class, rate design is the process used to develop the specific structure of rates to recover those costs. Although highly technical in nature, rate design also requires significant judgement and the consideration of broader rate setting principles in order to ensure fairness for customers and public interest outcomes.

The OEB's rate design policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors. The OEB has established principles and approaches which address many of the issues which arise during the rate design process. The OEB has also developed specific approaches to a number of specific rate design issues. One recent example is the change to residential rate design. The OEB's policy to re-design residential electricity distribution rates to be a fixed charge will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services. It is also a fairer way to recover the costs of providing electricity distribution service.[26]

### Rate Mitigation

The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities. For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers[27].

### Rate-setting Policies for Consolidations

On March 26, 2015 the OEB issued its *Report of the Board: Rate-Making Associated with Distributor Consolidation*. To encourage consolidations, the OEB established a policy that consolidating entities could defer rebasing for up 10 years. For electricity distributors deferring rebasing beyond five years, an earnings sharing mechanism (ESM) is required above ±300 basis points. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

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 OEB's reports.

To encourage consolidation, the OEB also 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.

On January 19, 2016 the OEB issued the *Handbook to Electricity Distributor and Transmitter Consolidations* (the MAADs Handbook). The MAADs Handbook provides

[26] *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015.

[27] The OEB's August 14, 2014 Decision on the quarterly rate adjustment mechanism process for natural gas distributors (EB-2014-0199), determined that advance notification to customers would be required going forward and a mitigation plan must be filed if a 25% or greater change is anticipated on the commodity portion of a typical residential system supply customer's bill.

guidance to applicants and stakeholders on how the OEB will review applications for consolidation.

### Working Capital Allowance

The (cash) working capital is the amount of cash that the utility requires to cover cash outlays in advance of when it recovers these amounts from customers. The working capital allowance is the allowance for this minimum amount of cash, reflected as capital not otherwise available for investment in assets that is factored into the determination of rate base.

The cash working capital requirements or working capital allowance is traditionally determined through a study that examines cash outlays and cash receipts and the leads and lags between the outlays and receipts.

For electricity distributors, the OEB currently allows for a working capital allowance of 7.5% of total operating expenses plus the cost of power[28] A distributor may propose an alternative which must be supported by a lead-lag study. Natural gas distributors, transmitters and OPG use utility-specific working capital allowances based on studies.

[28] The OEB letter regarding the *Allowance for Working Capital for Electricity Distribution Rate Applications*, June 3, 2015, provided an update to the OEB's policy for the calculation of the allowance for working capital for electricity distribution rate applications.

# EP-3

# ATTACH 4

# THE Decision and Partial Accounting Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024) Issued December 20, 2017

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

**EB-2017-0024**

## Alectra Utilities Corporation

## Application for electricity distribution rates and other charges beginning January 1, 2018

## DECISION AND PARTIAL ACCOUNTING ORDER
## December 20, 2017

Alectra Utilities Corporation (Alectra Utilities) filed an application with the Ontario Energy Board (OEB) on July 7, 2017 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), and under the OEB's *Filing Requirements for Incentive Rate-setting Applications* seeking approval for changes to its electricity distribution rates to be effective January 1, 2018. In its Decision on Issues List and Interim Rates and Procedural Order No.3, the OEB approved the establishment of three new accounts to track the change in capitalization for the Horizon rate zone (HRZ), Enersource rate zone (ERZ) and Brampton rate zone (BRZ).

The OEB made provision for comments on the recording details for these accounts to be submitted by the parties. Submissions were received from OEB staff, the School Energy Coalition (SEC), the Building Owners and Managers Association of Greater Toronto (BOMA), the Vulnerable Energy Consumers Coalition (VECC) and Alectra Utilities.

This Decision and Partial Accounting Order sets out the accounting details for the new accounts for the ERZ, BRZ and HRZ. The effective date will be February 1, 2017 and the accounts will continue until the OEB orders otherwise. The three new accounts will record the difference between the revenue requirement calculated using the pre-merger capitalization policies and the revenue requirement calculated with the new capitalization policy. The revenue requirement will be calculated based on actual costs each year for operations, maintenance and operating costs (OM&A), depreciation expense, income tax or payments in lieu of taxes (PILs), and return on capital (debt and equity).

This Accounting Order is partial as it does not include details on how the accounts will be disposed. Submissions on the options for disposition should be part of final arguments for this proceeding.

### Effective Date of the New Accounts

Alectra Utilities responded to undertakings provided at the Technical Conference held on November 30 and December 1, 2017. In undertaking JT.Staff-7, Alectra Utilities confirmed that the change in capitalization policy was effective on February 1, 2017 for the HRZ and ERZ - the date that Alectra Utilities was formed - and March 1, 2017 for the BRZ. Alectra Utilities maintained that the change in capitalization policy did not affect the fixed asset classes pre-merger or the opening balances.

Both Alectra Utilities and OEB staff proposed February 1, 2017 as the effective date for all three accounts.

Findings

The effective date for the three new accounts is February 1, 2017 on the basis that this is when the new capitalization policy was adopted for the newly formed Alectra Utilities. For the BRZ, the OEB recognizes that there will be no entry until March 1, 2017. In order to leave all options open for the disposition of the new accounts, the OEB will not establish an end date for these accounts. The accounts will remain open until such time as the OEB orders otherwise.

### Accounting Entries

SEC argued that amounts recorded should be based on the actual spending by Alectra Utilities in a given year. SEC’s proposed approach for accounting entries was to calculate the regulatory revenue requirement on an as-spent basis compared to the revenue requirement assuming the accounting change had not been made. The difference would be recorded in the new capitalization accounts. VECC supported the submission by SEC.

Alectra Utilities’ proposal would record the impact resulting from the change to the capitalization policy for the following:

- OM&A expenditures in each year
- depreciation expense over the life of the underlying assets
- income tax or PILs for the amount paid to taxation authorities
- the annual return on the cumulative capital

OEB staff submitted that entries should be based on each utility's rebasing year. OEB staff's proposal would record the difference between the revenue requirement approved for the rebasing years as compared to the revenue requirement for the respective rebasing years had the new capitalization policy been in place. BOMA agreed with the submissions of OEB staff, subject to the caveat that the same process would take place in each rate year.

OEB staff further submitted that only 11/12ths of the amount calculated should be recorded for 2017. Both SEC and Alectra Utilities disagreed with this proposal. SEC argued that 100% of any difference in the regulatory revenue requirement for 2017 should be recorded. Alectra Utilities argued that the amounts should be based on the actual impact calculated on an annual basis.

SEC further noted that there is a collateral issue with respect to the earnings sharing mechanism (ESM) for the HRZ. The intent of the ESM mechanism is to share 50% of any earnings with customers above the OEB-approved return on equity. The change in the capitalization policy affects the earnings to be shared. SEC submitted that there should be an adjusting entry to the ESM account.

Findings

The three new accounts will record the difference between the revenue requirement calculated using the pre-merger capitalization policies and the revenue requirement calculated with the new capitalization policy. The revenue requirement will be calculated each year based on actual costs for OM&A, depreciation expense, income tax or PILs, and return on capital (debt and equity).

This approach will result in the actual financial consequences of the change to the capitalization policy being recorded in the new accounts.

The OEB agrees with SEC that it is important to ensure that the new accounts for the capitalization change and the ESM account are coordinated to ensure there is no double-counting of earnings for the HRZ. The OEB will address this issue at the time it is considering the approach to disposition of the new accounts. This will ensure that all options remain open.

Alectra Utilities shall maintain records to show its calculations for the revenue requirement for each rate zone to at least the level of detail provided in Table 1 of the undertaking JT.Staff-7.

## Account Numbers

OEB staff proposed account numbers for the three new accounts as follows:

Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes ERZ

Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes BRZ

Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes HRZ

Findings

The OEB approves the account number and consistent descriptions proposed by OEB staff.

## THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Alectra Utilities shall establish the following accounts to record the changes to the revenue requirement, as defined in this Decision, resulting from the change in Alectra Utilities' capitalization policy:
   - Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes ERZ
   - Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes BRZ
   - Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes HRZ
2. The accounts are effective February 1, 2017 and will remain open until the OEB orders otherwise.
3. Interest will be recorded on balances in the accounts at the OEB prescribed interest rate for deferral and variance accounts in separate sub accounts of these accounts for each rate zone.

**DATED** at Toronto, December 20, 2017

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirstin Walli
Board Secretary

# EP-3

# ATTACH 5

# The Decision and Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024) Issued April 6, 2018

Ontario

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

# DECISION AND ORDER

## EB-2017-0024

## ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates and other charges beginning January 1, 2018**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**Revised: April 6, 2018**

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# 1 INTRODUCTION AND SUMMARY

Alectra Utilities Corporation (Alectra Utilities) filed an application with the Ontario Energy Board (OEB) on July 7, 2017 under section 78 of the *Ontario Energy Board Act*, *1998* (OEB Act), and under the OEB's *Filing Requirements for Incentive Rate-setting Applications* seeking approval for changes to its electricity distribution rates to be effective January 1, 2018. Under section 78 of the OEB Act, a distributor must apply to the OEB to change the rates it charges its customers.

Alectra Utilities provides electricity distribution services to approximately one million customers in the cities of Mississauga, Hamilton, St. Catharines, Brampton, Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan, as well as Collingwood, Stayner, Creemore and Thornbury under OEB Electricity Distributor Licence no. ED-2016-0360.

Alectra Utilities asked the OEB to approve its rates for 2018 using the price-cap incentive rate-setting (Price Cap IR) mechanism for its Brampton, Enersource and PowerStream rate zones (RZ) and an annual adjustment for the Horizon Utilities RZ related to the fourth year of the 2015 to 2019 custom incentive rate-setting (Custom IR) rate plan five-year term.

Under the Price Cap IR option, the approved rates are adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of each rate zone's efficiency.

Under the Custom IR option, utilities with significant operating and capital expenditure needs may apply for a multi-year Custom IR plan where rates are set for all years of the plan term, subject to specific adjustments.

Alectra Utilities also applied for incremental capital funding for the Brampton, Enersource and PowerStream RZs under the Incremental Capital Module (ICM) funding option.

The OEB makes the following findings:

- The OEB approves the annual adjustments proposed by Alectra Utilities for the Horizon Utilities RZ for year four of the five-year term of its Custom IR framework.
- The OEB approves a price-cap adjustment of 0.9% for the Brampton, Enersource and PowerStream RZs.

- The OEB accepts the distribution system plan, including the applicable customer engagement, for the Enersource RZ for the purposes of considering the proposed ICMs for the Enersource RZ.
- The OEB assessed the 22 ICM projects against the three tests for eligibility of materiality, need and prudence. The OEB approves $28.79 million of the requested $56.18 million in ICM funding. The OEB does not approve new deferral accounts for the Metrolinx Crossing Remediation Project. The OEB requires Alectra Utilities to file a consolidated DSP as a filing requirement with any ICM application requesting rate changes for 2020 rates and beyond.
- Alectra Utilities is required to continue to accumulate amounts in its deferral accounts for the change in capitalization policy for the Brampton, Enersource and PowerStream RZs, and file a proposal for disposition of balances for 2019 rates. The impact of the change in capitalization policy for the Horizon Utilities RZ will be dealt with through the earnings sharing mechanism until the end of the term for its Custom IR framework.
- Rates for the annual adjustment to base rates for the Horizon Utilities RZ and for price-cap adjustment for the Brampton, Enersource and PowerStream RZs will be effective January 1, 2018. Other rate changes resulting from this Decision, including the ICM rate riders, will be effective May 1, 2018. Rates will be implemented May 1, 2018.

# 2 THE PROCESS

The OEB's policy for rate setting is set out in the "*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach"* (RRFE, now referred to as the RRF) and the *"Handbook for Rate Applications"* (Rate Handbook). The RRF provides the distributor with performance-based rate application options that support the cost effective planning and efficient operation of a distribution network. The Rate Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications.

Alectra Utilities filed an application on July 7, 2017 for 2018 rates under the Price-Cap IR of the RRF for the Brampton, Enersource and PowerStream RZs and an annual update for the Horizon Utilities RZ arising from the five-year Custom IR framework previously approved by the OEB. The OEB issued a Notice of Application on August 18, 2017, inviting parties to apply for intervenor status. The Association of Major Power Consumers in Ontario (AMPCO), the Building Owners and Managers Association of Greater Toronto (BOMA), Capredoni Enterprises Ltd. (CEL), the City of Hamilton, Consumers Council of Canada (CCC), the Power Workers' Union (PWU), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) applied for intervenor status. All except for CEL and PWU were granted intervenor status. OEB staff also participated in this proceeding.

Both CEL and PWU appealed their denial of intervenor status. The OEB denied CEL's appeal, but granted PWU's requested relief on the basis of the new information provided in its appeal.

The OEB issued Procedural Order No.1 on September 8, 2017 (corrected and re-issued September 15, 2017). This order established, among other things, the timetable for a written interrogatory discovery process, the filing of a proposed issues list and a settlement conference.

A settlement conference was held on October 25, 2017 and October 26, 2017, which was attended by Alectra Utilities and the intervenors, with the exception of the City of Hamilton. No settlement was reached.

The OEB issued its Decision on Issues List and Interim Rates and Procedural Order No. 3 on November 17, 2017, which among other matters established that a Technical Conference would take place on November 30, 2017 and December 1, 2017. All parties filed written submissions on the issues.

# 3 STRUCTURE OF THE DECISION

This Decision and Order (Decision) is organized to substantially follow the Issues List of November 17, 2017. Following the introductory sections, this Decision and Order addresses matters in sections entitled:

- Horizon Utilities Rate Zone – Year 4 Custom IR Update
- IRM Model Filings for the Brampton, Enersource and PowerStream Rate Zones
- Enersource Rate Zone Distribution System Plan
- Customer Engagement
- ICMs for the Brampton, Enersource and PowerStream Rate Zones
- ICM True-up
- Retail Transmission Service Rates
- Deferral and Variance Accounts
- Residential Rate Design
- Capitalization Policy
- Monthly Billing
- Effective Date

# 4 DECISION ON THE ISSUES

## 4.1 Horizon Utilities Rate Zone – Year 4 Custom IR Update

Horizon Utilities filed a Custom IR application with the OEB in 2014[1] requesting approval of five years of distribution rates for the five-year period from 2015 to 2019 with rates effective January 1st of each year. A partial settlement proposal was filed on September 22, 2014, which was accepted by the OEB, and a Decision and Order on the outstanding matters was subsequently issued establishing rates to be effective January 1, 2015.

The approved settlement proposal set out annual updates for rates to be filed for years two to five of the Custom IR term, for rates effective January 1st. The current application is the annual update for year four of the term. The approved settlement proposal also included “reopeners” that could result in further adjustments to rates. Alectra Utilities indicated that none of these reopeners applied to 2018 rates. Some intervenors and OEB staff submitted that a capitalization policy change triggered by the Alectra Utilities merger, and the cost implications of the transition to monthly billing, need to be considered.

The OEB-approved settlement proposal indicated that Horizon Utilities’ rates would be adjusted annually for a number of items. A number of the potential adjustments to the rates for the Horizon Utilities RZ are dealt with in subsequent sections of this Decision because they are relevant to other rate zones. These include:

- Deferral and Variance Accounts (DVAs), including the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)
- Residential Rate Design
- Capitalization Policy
- Monthly Billing

The remaining annual adjustments proposed by Alectra Utilities for the Horizon Utilities RZ in 2018 are addressed below.

[1] EB-2014-0002.

### a) Changes in the Cost of Capital

Alectra Utilities stated that the annual filing had been updated for the 2017 cost of capital parameters issued by the OEB on October 27, 2016. Alectra Utilities noted that on November 23, 2017, the OEB had issued its cost of capital parameters for 2018 and stated that it would update these parameters, as applicable, for the Horizon Utilities RZ when it prepares the draft rate order. OEB staff submitted that this was appropriate. No other parties expressed any concerns in this area.

### Findings

As per the approved settlement proposal, the OEB approves an update to the cost of capital for the Horizon Utilities RZ. Alectra Utilities is directed to apply the OEB-approved 2018 cost of capital parameters[2] in the draft rate order.

### b) Changes in the Working Capital Allowance

Alectra Utilities stated that it had made changes to the working capital allowance included in rate base for the Horizon Utilities RZ as a result of changes to the cost of power, which it stated were consistent with OEB policies and direction.

OEB staff, in its submission,[3] noted that Alectra Utilities had updated the cost of power and global adjustment (GA) based on the OEB's RPP Report[4] up to the period ending April 30, 2018. Alectra Utilities had then increased the RPP rates and global adjustment by inflation for the period May 1, 2018 to October 30, 2018, and again for the period November 1, 2018 to April 30, 2019, while also applying the global adjustment (GA) modifier to all non-RPP customers.

OEB staff noted that the RPP prices and the GA modifier are only applied to "specified customers" as defined in the Ontario *Fair Hydro Plan Act, 2017* (Fair Hydro Plan) and calculated based on a proxy Toronto Hydro customer. OEB staff submitted that the cost of power calculation should not be inflated because of its dependency on the Toronto Hydro 2018 bill impact. OEB staff concluded that since RPP prices and the GA modifier have not yet been calculated for May-December 2018, the cost of power calculation

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[2] "Cost of Capital Parameter Updates for 2018 Cost of Service and Custom Incentive Rate-setting Applications, November 23, 2017.
[3] OEB Staff Submission, January 16, 2018, p.7.
[4] "Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018", June 22, 2017.

should use the current approved RPP prices and GA modifier for the entire year. In addition, the GA modifier should only be applied to non-RPP customers that fall within the definition of “specified customer” in the Fair Hydro Plan.

OEB staff further noted that since 2017 uniform transmission rates (UTRs) were not available at the time of the filing, Alectra Utilities used 2016 UTRs as a proxy rate to calculate 2018 retail transmission service rates (RTSRs). Given the OEB approved UTRs for 2017,[5] the RTSRs should be updated accordingly.

Alectra Utilities disagreed with OEB staff and maintained that an inflation adjustment should be used to determine rates for the May 1, 2018 to October 31, 2018 and November 1, 2018 to December 31, 2018 periods. Alectra Utilities stated that to determine rates for the May to December 2018 period, it had applied a 2% inflation adjustment for the purpose of the cost of power calculation and that this was consistent with the intent of the Fair Hydro Plan.

Alectra Utilities agreed with OEB staff that the GA modifier should only be applied to non-RPP customers that fall within the definition of “specified customer” in the Fair Hydro Plan, but argued that the GA modifier had been applied appropriately to all non-RPP customers. Alectra Utilities clarified that the impact to the GA rates from the implementation of the Fair Hydro Plan was only applied to residential and GS<50 kW non-RPP customers.

Alectra Utilities confirmed that an update would be made for the 2017 UTRs in its draft rate order.

No other parties commented on these matters.

## Findings

The OEB approves an inflationary adjustment to the 2017 RRP prices for calculating the 2018 cost of power from May 1, 2018 to December 31, 2018 in the working capital allowance calculation.  The Fair Hydro Plan requires rate increases to be held to the rate of inflation for four years, based on the Ontario consumer price index (CPI). The OEB finds it reasonable for Alectra Utilities to increase the 2017 RRP prices by inflation for the purposes of its 2018 cost of power forecast for the working capital allowance calculation. However, Alectra Utilities’ use of 2% for the inflation factor overstates the trend in the CPI over the past several years. Alectra Utilities is directed to update its

[5] Decision and Rate Order “2017 Uniform Transmission Rates”, EB-2017-0280, November 23, 2017.

cost of power calculation for an inflation increase of 1.6% to the commodity cost for RPP customers (based on the Ontario CPI averaged over the past three years).[6]

Since the time of Alectra Utilities' reply submission, the OEB has approved 2018 UTRs.[7] The OEB approves the use of these OEB-approved 2018 UTRs in the calculation of the 2018 cost of power.

The OEB accepts Alectra Utilities' approach with respect to the GA modifier.

The OEB directs Alectra Utilities to update the 2018 working capital allowance in the draft rate order reflecting this Decision.

### c) Earnings Sharing Mechanism (ESM)

The approved settlement proposal provided for earnings in excess of the approved return on equity (ROE) to be shared on a 50/50 basis between Horizon Utilities and its customers. A deferral account was created to track earnings in excess of the OEB's annual approved ROE.

Alectra Utilities calculated a 2016 ROE of 9.877% for the purpose of the earnings sharing mechanism (ESM), resulting in earnings sharing for 2016 of $695,975 given that the calculated ROE is greater than the approved ROE of 9.19%.

Alectra Utilities stated that it had reported $662,467 in deferral account 1508 Sub-account Earnings Sharing Variance Account in the 2016 Reporting and Record Keeping Requirements (RRR) for Horizon Utilities, based on the best estimate at the time of the calculation. However, an update to the earnings for actuals resulted in an additional $33,508 of earnings to be shared with customers. Alectra Utilities proposed that this $33,508 be reported in the 2017 deferral account and the full amount be disposed of in 2018.

OEB staff submitted that Alectra Utilities' calculation of the ESM was in accordance with the RRR and the approved settlement proposal. However, OEB staff argued that the full balance of $695,975 should be recorded in the 2016 ESM deferral account to avoid future confusion as to the origin of the $33,508 in the 2017 deferral account balance.

[6] https://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ09g-eng.htm
[7] Decision and Rate Order "2018 Uniform Transmission Rates" EB-2017-0359, February 1, 2018.

OEB staff submitted that in the event Alectra Utilities was unable to do so, its proposed methodology was acceptable.

Alectra Utilities disagreed with OEB staff's proposed approach and stated that it intended to report the $33,508 difference in the 2017 deferral account, identified as relating to the 2016 ESM calculation, to avoid confusion.

No other parties expressed concerns with this matter.

**Findings**

The OEB accepts the 2016 ROE calculation of 9.87% for the purpose of the earning sharing mechanism, which is greater than the OEB-approved ROE of 9.19%. The OEB approves earnings sharing in the amount $695,975 for 2016. The OEB approves Alectra Utilities' proposal to record $33,508 in the 2017 deferral account balance. The OEB accepts Alectra Utilities' assurance that it can identify that this amount is related to 2016 when the 2017 earnings sharing is determined.

### d) Capital Investment Variance Account (CIVA)

The approved settlement proposal provided for a deferral account to refund ratepayers any difference in the revenue requirement should in-service capital additions be lower than the approved forecast. Each year, Horizon Utilities is required to determine the impact to revenue requirement of the variance in its cumulative capital additions for the period from January 1, 2015 to the end of the relative year, as compared to the baseline.

Alectra Utilities sought approval of Horizon Utilities' 2016 capital additions of $44.3 million as reported in the RRR for the purpose of calculating the 2016 CIVA entry, which compares to the forecast capital additions of $41.1 million approved as part of the approved settlement proposal. Alectra Utilities stated that as actual capital additions were higher than the forecast of capital additions in the Custom IR application, it had not established or made an entry to the 1508 Sub-account CIVA for the Horizon Utilities RZ.

OEB staff submitted that the calculation for the purpose of entry was consistent with the approved settlement proposal. No other parties expressed any concerns with this calculation.

### Findings

The OEB approves the proposed calculation for the CIVA as it is consistent with the approved settlement proposal. The OEB accepts that no CIVA entry should be made for 2016 as actual capital additions were higher than forecast.

## e) Efficiency Adjustment

The approved settlement proposal included an efficiency adjustment intended to incent the former Horizon Utilities to maintain or improve its cohort position based on the OEB's stretch factor assignments. The efficiency adjustment was to operate as a proxy stretch factor in the event that Horizon Utilities was to be placed in a less efficient cohort in any year during the Custom IR term. Horizon Utilities was in the Group III cohort in 2015 and remains in Group III for the purpose of calculating 2018 stretch factors.

Alectra Utilities submitted that no efficiency adjustment was appropriate. OEB staff in its submission agreed. No other party expressed any concerns on this matter.

### Findings

The OEB finds that no efficiency adjustment is required in 2018 as Horizon Utilities remains in the Group III cohort.

## f) Special Studies Deferral Account

The approved settlement proposal included a deferral account to record costs related to the development of a study to determine the appropriateness of the specific service charges for the Horizon Utilities RZ. Alectra Utilities confirmed that no studies had commenced and no costs had been recorded related to this matter.

No parties made submissions on this issue.

### Findings

The OEB accepts that no study costs have been incurred related to specific service charges and no entry in the deferral account is required in 2018. While this study was a requirement of the approved settlement proposal, Alectra Utilities noted that the OEB has commenced its own review of specific service charges, and Alectra Utilities has agreed to participate in this review.

### g) Revenue-To-Cost Ratio Adjustments

The OEB approved rate changes in 2016[8] for the street lighting class resulting from OEB policy changes to the street lighting adjustment factor and the revenue-to-cost ratio.[9] The OEB directed Horizon Utilities to phase in the revenue to cost changes over the 2015 to 2019 Custom IR term.

Alectra Utilities requested approval to reduce the 2018 street lighting class' revenue-to-cost ratio by 6.6% to 106.66%.

OEB staff submitted that the proposed rate design was consistent with the OEB's decision on the 2016 Custom IR Update and the OEB's policies. No other party commented on this proposed change.

**Findings**

The OEB approves the proposed change to the revenue-to-cost ratio for the street lighting rate class in 2018, as the change is consistent with the OEB's decision.[10]

## 4.2 IRM Model Filings for the Brampton, Enersource and PowerStream Rate Zones

The OEB will first address the following issues, and provide reasons for approving Alectra Utilities' proposals relating to each of them:

- Price Cap Adjustment
- Eligible Investments for Connection of Qualifying Generation Facilities

The OEB will address Alectra Utilities' request for funding through incremental capital modules (ICM) in subsequent sections. A number of the potential adjustments to the rates for the Brampton, Enersource and PowerStream RZs are dealt with in subsequent sections of this Decision because they are relevant to all four rate zones. These include:

- Retail Transmission Service Rates (RTSRs)

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[8] Decision and Order Horizon Utilities Corporation "Application for electricity distribution rates and other charges beginning January 1, 2016", EB-2015-0075, December 10, 2015.
[9] "Issuance of New Cost Allocation Policy for Street Lighting Rate Class", EB-2012-0383, June 12, 2015.
[10] EB-2015-0075.

- Deferral and Variance Accounts (DVAs), including the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)
- Residential Rate Design
- Capitalization Policy
- Monthly Billing

## a) Price Cap Adjustment

Alectra Utilities seeks to increase its rates in the Brampton, Enersource and PowerStream RZs, effective January 1, 2018, based on a mechanistic rate adjustment using the OEB-approved ***inflation minus X-factor*** formula applicable to Price Cap IR applications.

The components of the Price Cap IR formula applicable to all three of Alectra Utilities' RZs are set out in Table 1, below.

Inserting these components into the formula results in a 0.90% increase to LDC's rates: ***0.90% = 1.20% - (0.00% + 0.30%)***.

**Table 1: Price Cap IR Adjustment Formula**

| Components | | Amount |
|---|---|---|
| Inflation Factor[11] | | 1.20% |
| X-Factor | Productivity[12] | 0.00% |
| | Stretch (0.00% – 0.60%)[13] | 0.30% |

The inflation factor of 1.20% applies to all Price Cap IR applications for the 2018 rate year.

[11] Report of the OEB – "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors." EB-2010-0379, December 4, 2013.
[12] Ibid.
[13] The stretch factor groupings are based on the Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2016 Benchmarking Update", prepared by Pacific Economics Group LLC., July 2017.

The X-factor is the sum of the productivity factor and the stretch factor. It is a productivity offset that will vary among different groupings of distributors. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors with a tangible incentive to improve efficiency or else experience declining net income.

The productivity component of the X-factor is based on industry conditions over a historical study period and applies to all Price Cap IR applications for the 2018 rate year.

The stretch factor component of the X-factor is distributor specific. The OEB has established five stretch factor groupings, each within a range from 0.00% to 0.60%. The stretch factor assigned to any particular distributor is based on the distributor's total cost performance as benchmarked against other distributors in Ontario. The most efficient distributor would be assigned the lowest stretch factor of 0.00%. Conversely, a higher stretch factor would be applied to a less efficient distributor (in accordance with its cost performance relative to expected levels) to reflect the incremental productivity gains that the distributor is expected to achieve. The stretch factor assigned to all three of Alectra Utilities' RZs is 0.30%.

### Findings

Alectra Utilities acknowledged in its reply submission that the price cap adjustment for the Enersource RZ must be updated to reflect a 0.3% stretch factor. The OEB approves the proposed 0.90% Price Cap IR adjustment for the Brampton, Enersource and PowerStream RZs. The OEB finds the calculation is in accordance with the updated 2018 parameters approved by the OEB. The 0.90% adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.[14]

[14] Price Cap IR and Annual IR Index adjustments do not apply to the following rates and charges: rate riders, rate adders, low voltage service charges, retail transmission service rates, wholesale market service rate, rural or remote electricity rate protection charge, standard supply service – administrative charge, transformation and primary metering allowances, loss factors, specific service charges, microFIT charge, and retail service charges.

### b) Eligible Investments for Connection of Qualifying Generation Facilities

i) *Brampton RZ*:

Alectra Utilities noted that in the 2015 Cost of Service Rate Application[15] the OEB had approved Hydro One Brampton Networks' (Hydro One Brampton) request for the funding of Renewable Generation Connection Provincial amounts included in its detailed DSP. This funding is to be recovered through the Independent Electricity System Operator (IESO) relating to renewable enabling improvement investments and renewable expansion investments (investments for connecting renewables) from 2015 to 2019.

Alectra Utilities is requesting funding for investments for connecting renewables of a total of $117,963 in 2018 or $9,830 per month from all provincial ratepayers for the Brampton RZ.

*ii) Enersource RZ:*

Alectra Utilities noted that the former Enersource Hydro Mississauga Inc. (Enersource) had filed a basic Green Energy Plan as part of its 2013 cost of service application,[16] which provided a forecast of the number of projects and costs related to the connection of feed-in-tariff (FIT) and microFIT projects until 2016.

As part of this IRM application, Alectra Utilities provided an update to the number of scheduled projects for the Enersource RZ to include 2016 actual amounts and an estimate for 2017 and 2018.

Alectra Utilities is requesting collection of funding of investments for connecting renewables of a total of $133,384, or $11,115 per month, in 2018 from all provincial ratepayers for the Enersource RZ.

*iii) PowerStream RZ:*

Alectra Utilities noted that in the 2016 PowerStream Inc. Custom IR Rate Application (PowerStream Custom IR application),[17] the OEB had approved PowerStream's request for the funding of investments for connecting renewables included in its detailed DSP, to be recovered through the IESO from 2016 to 2020.

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[15] EB-2014-0083.
[16] EB-2012-0033.
[17] EB-2015-0003.

Alectra Utilities is requesting collection of a total of $266,079 in 2018 or $22,173 per month from all provincial ratepayers for the PowerStream RZ.

OEB staff submitted that Alectra Utilities' renewable generation funding requests for the three rate zones had been correctly calculated. No intervenor opposed Alectra Utilities request for these cost recoveries.

**Findings**

The OEB approves the proposed funding of investments for connecting renewables, which were previously approved by the OEB.  The approved amounts are $117,963 for the Brampton RZ, $133,384 for the Enersource RZ and $266,079 for the PowerStream RZ.

## 4.3 Enersource Rate Zone Distribution System Plan

As part of this application, Alectra Utilities filed a distribution system plan (DSP) for the Enersource RZ for a five-year term from 2018 to 2022 to support the request for approval of an ICM. In a previous application,[18] the OEB did not approve an ICM for 2016 forecast capital expenditures and required Enersource to file a final DSP before the OEB would consider ICM funding.

Alectra Utilities stated that the Enersource RZ DSP:

- Outlines Alectra Utilities' strategy of taking a complete lifecycle approach to the management of its Enersource RZ assets
- Includes sufficient information to support the proposed ICM for the Enersource RZ
- Provides justification for the proposed expenditures in the Enersource RZ relating to the distribution system and general plant for 2017  and the 2018 to 2022 period, including investment and asset-related maintenance expenditures

OEB staff, while noting that the OEB does not "approve" DSPs, agreed that the Enersource RZ DSP allows for an assessment of the ICM expenditures proposed in the application. However, OEB staff did express concerns that the DSP does not

[18] EB-2015-0065, 2016 distribution rate application for Enersource in which a draft DSP was filed.

adequately explain why some planned capital expenditures are treated as base capital expenditures while others are classified as ICM project expenditures. Alectra Utilities submitted that the OEB Filing Requirements do not require this.

SEC, AMPCO, VECC and BOMA all expressed concerns with the DSP. SEC argued that the OEB should accept the Enersource RZ DSP, but neither approve it nor reject it. SEC acknowledged that Alectra Utilities had complied with the requirement from the EB-2015-0065 proceeding to file a DSP but argued that the Enersource RZ DSP is an "outdated pre-merger document", has no value and is not helpful to the OEB.

SEC also submitted that the Vanry Report, filed by Alectra Utilities related to the DSP, should not be relied upon by the OEB as SEC questioned Vanry's expertise and independence. AMPCO submitted that due to the timing of the Enersource RZ DSP, Alectra Utilities did not incorporate Vanry's recommendations.

VECC argued that there is no discussion in the Enersource RZ DSP as to the coordination of information technology or regarding changes to building requirements, rolling stock or any other aspects likely to change as rationalization occurs in the new company.

BOMA argued that the Enersource RZ DSP is not in accordance with the OEB's RRF policies, particularly because it does not reflect customer needs and preferences.

Alectra Utilities submitted that the assertion that the DSP is a pre-merger document is incorrect as parties making this argument appeared to be equating the draft DSP filed by Enersource in a previous proceeding[19] with the DSP filed as part of the present application.

Alectra Utilities submitted that with respect to Vanry, it provided its professional opinion that the Enersource RZ DSP and the underlying methodologies, analysis, and supporting documentation were in accordance with the OEB's Chapter 5 Filing Requirements. Vanry found that the Enersource RZ DSP "represents a well-reasoned, fact based assessment of the needs of the system" and that "it reflects the desires of customers and the concerns of relevant stakeholders."[20]

[19] Ibid.
[20] Vanry Report, p. 32.

### Findings

The OEB finds that the DSP filed by Alectra Utilities is sufficient for the OEB to make its decision on the 2018 ICM for the Enersource RZ. Options considered by Alectra Utilities were helpful in assessing the ICM projects. The OEB notes that Alectra Utilities plans to file a consolidated DSP by April 2019, and this would effectively update and replace the Enersource DSP.[21] This consolidated DSP is discussed further in a subsequent section of the Decision.

The OEB disagrees with Alectra Utilities' claim that it is not necessary to have an adequate explanation of why some capital is regarded as "base" and other as "incremental". Given the distinction between base and incremental capital amounts necessary in an ICM application, including an explanation and rationale for allocating projects to each category is a logical addition. Filing requirements cannot anticipate all needs and circumstances, including an ICM application with 22 projects .While the OEB has accepted the DSP for the purposes of setting 2018 rates, this distinction between base and incremental will become more critical should Alectra Utilities file any further applications for incremental funding of capital and particularly as it optimizes its capital plans under a consolidated DSP.

Alectra Utilities stated that Vanry's feedback informed Alectra Utilities in developing its DSP. This type of external feedback can be helpful to a utility in forming its plans. There is no requirement to have a third party review of a DSP, unless specifically ordered by the OEB.

## 4.4 Customer Engagement

The OEB's Handbook for Utility Rate Applications (Rate Handbook) advises that "customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs".[22]

Alectra Utilities stated that it undertook customer engagement related to the DSP for the Enersource RZ and the ICMs for the Brampton RZ, Enersource RZ and PowerStream

[21] Application Exhibit 1, Tab 1, Schedule 1 page 4, footnote 2. The filing of the DSP was a commitment made at the oral hearing for the EB-2016-0025 proceeding.
[22] "Handbook for Utility Rate Applications", October 1, 2016, p.11.

RZ. Alectra Utilities engaged Innovative Research Group (IRG) to prepare a Customer Engagement Report. The customer engagement process included a Customer Feedback Portal on Alectra Utilities' website and a telephone survey. The engagement process was designed to ensure Alectra Utilities received the input needed to make key decisions regarding the application, and customers had the information they needed to provide meaningful responses to Alectra Utilities' questions.

Alectra Utilities indicated that the application was filed only months after the merged utility was established, yet it made a conscious effort to include initial, partial customer engagement results in the application, which were generally consistent with the final results.

BOMA, CCC, SEC, VECC and OEB staff were critical of Alectra Utilities' customer engagement process and its interpretation of the results.

BOMA submitted that Alectra Utilities downplayed customers' strong statements of resistance to further rate hikes. CCC submitted that there was no evidence that customers understood what "incremental" capital spending meant or that customers asked Alectra Utilities to spend more. SEC submitted that Alectra Utilities "claimed its customers think it should spend more money to maintain the current level of reliability. That was not what the customers said". Similar to CCC, SEC argued that no customer suggested that Alectra Utilities should spend more. VECC submitted that the survey did not meet the scientific criteria as it was not random and the sample size was insufficient. In particular, VECC claimed that the online results were biased as survey respondents were allowed to self-select whether or not to participate in a survey. OEB staff submitted that Alectra Utilities did not sufficiently articulate the value proposition for customers, the impact on customer service and rates, postponement options or the cost versus reliability trade-offs associated with the proposed spending.

In its reply submission, Alectra Utilities argued that some intervenors misunderstood the Rate Handbook which states the OEB will consider, among other things, "the quality of the utility's analysis of customer input."[23] In addition to quality, Alectra Utilities claimed it had gathered the largest amount of customer feedback ever collected by an Ontario utility.

Alectra Utilities argued that the intervenors and OEB staff failed to recognize the real, practical choices that have to be made in conducting customer engagement. Alectra

[23] Ibid, p.12.

Utilities submitted that it had followed the OEB's guidance and its approach was consistent with other customer engagement efforts by IRG and common to any study of public spending priorities.

Alectra Utilities noted SEC's concern but argued that the results on customer need and reliability questions all confirmed that there was no need to offer an option to increase reliability. Alectra Utilities noted that CCC and SEC questioned the interpretation of the results, specifically whether or not customers are willing to pay more. Alectra Utilities argued that these assertions were contrary to the actual evidence, as it is misleading to suggest customers want lower rates to the exclusion of all other outcomes. Alectra Utilities concluded that while customers are concerned about their electricity bills, most support some form of investment program that ensures a consistently reliable and modern distribution system that addresses growth and system needs.

**Findings**

The OEB finds Alectra Utilities' DSP-related customer engagement to be adequate. The OEB relied on the Enersource RZ DSP-related customer engagement to inform its ICM decisions.

While the ICM-related customer engagement was extensive, the OEB found the evidence did not provide clarity on fundamental questions pertinent to the ICM requests. For example, the OEB did not find questions that quantified the proposed rate increases of the options in 2018 or the cumulative cost during the deferred rebasing period. As a result, Alectra Utilities has not provided adequate evidence of "balancing its customers concerns with the costs and reliability" as expected under the RRF.

The OEB found customer responses related to specific ICM projects informative. Project-specific customer engagement should be included if investment options with tradeoffs are available (e.g. replacing leaking transformers) or if customers are directly affected by a project (e.g. rear lot remediation).

The OEB acknowledges that the Rate Handbook does not specifically address customer engagement for an ICM. Yet it is incumbent on a utility to engage continually with its customers and to use the results of that engagement to inform the development of utility plans.

The OEB appreciates the limited time after the merger and before filing the application. Such time constraints should not be a constraint going forward. In addition, the OEB encourages Alectra Utilities to consider the submissions of intervenors and OEB staff in order to revise and refine any future ICM-related customer engagement.

## 4.5 ICMs for the Brampton, Enersource and PowerStream Rate Zones

The OEB has determined that Alectra Utilities is eligible for incremental funding for certain capital projects in 2018 rates through ICM rate riders.

The OEB's policy for the funding of incremental capital is set out in the Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014 (Funding of Capital Report)[24] and the subsequent Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report (Supplemental Report) (collectively referred to as ICM policy). The OEB provided further policy direction for the availability of incremental capital modules following a merger in the Report of the Board Rate-Making Associated with Distributor Consolidation (MAADs policy)[25] and in the Handbook to Electricity Distributor and Transmitter Consolidations (MAADs Handbook).

The OEB first addresses the overall eligibility for ICM recovery and the criteria that must be met for this incremental funding. The OEB then assesses each project against that criteria.

### a) Overall Eligibility for ICM Recovery

*General Comments*

The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan that are incremental to a materiality threshold.[26] The ICM is a funding mechanism for significant, incremental and discrete capital projects for which a utility is granted rate recovery in advance of its next rebasing application.

Alectra Utilities stated that its proposed ICM projects are in accordance with OEB policies as reflected in the Funding of Capital Report and the Supplemental Report.

PWU supported Alectra Utilities' ICM application and submitted that the OEB should approve the ICM project funding in full.

[24] EB-2014-0219.
[25] EB-2014-0138.
[26] Funding of Capital Report, September 18, 2014, p. 4.

OEB staff submitted that only two of the proposed ICM projects met all established tests, as discussed later in this Decision. OEB staff submitted that the remaining projects fail at least one of the tests and should not be approved. BOMA also submitted that only two of the ICM investments should be approved.

SEC, CCC and AMPCO submitted that none of the proposed incremental capital amounts should be approved. SEC, CCC and AMPCO also all argued the merger savings are a relevant consideration and provide context for ICM applications. SEC argued that this case should cause the OEB to rethink its policies and whether they are appropriately customer-focused.

Alectra Utilities submitted that OEB staff, BOMA, SEC, CCC, AMPCO and VECC all took issue with the application of the OEB's ICM policy, but the OEB has already determined on multiple occasions that the ICM is available to consolidating distributors.

In the ICM policy, the OEB established three tests for eligibility for the ICM: Materiality, Need and Prudence. These three tests are discussed in the sections that follow.

*Materiality*

There are two materiality tests related to ICM applications. The first test is the ICM materiality threshold formula, which serves to demonstrate the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor".[27]

Alectra Utilities stated that it had appropriately calculated the following materiality thresholds for the three rate zones which results in the following:

- Brampton RZ has a maximum eligible incremental capital amount of $7,113,613, which means that its proposal to recover $6,800,377 through the ICM for this rate zone is within the OEB's acceptable range.
- PowerStream RZ has a maximum eligible incremental capital amount of $25,891,795, which means that its proposal to recover $25,136,316 through the ICM for this rate zone is within the OEB's acceptable range.

[27] Funding of Capital Report, p. 17.

- Enersource RZ has a maximum eligible incremental capital amount of $39,624,419, which means that its proposal to recover $24,247,022 through the ICM for this rate zone is within the OEB's acceptable range.

No party took issue with Alectra Utilities' calculation of the ICM materiality threshold for each rate zone.

The OEB adopted a second, project-specific materiality test in the Funding of Capital Report, as identified in a decision for Toronto Hydro Electric System Limited (Toronto Hydro).[28] The project-specific materiality test is as follows:

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[29]

Alectra Utilities submitted that each capital project was eligible for an ICM as each project exceeded the project-specific materiality level established for each rate zone.

OEB staff submitted that a project proposed for ICM treatment must not only meet the OEB-defined materiality thresholds, but must also clearly have a significant influence on the distributor. OEB staff argued that a proposed project does not qualify simply by characterizing it as a separate project that meets the materiality thresholds; the ICM was not intended to be a "capital budget top-up".

BOMA submitted that not every capital investment proposal that exceeds the "project materiality" threshold can be said to have a significant influence on a utility. BOMA argued that Alectra Utilities is the appropriate utility in respect of which the degree of impact should be addressed. BOMA acknowledged that the OEB has authorized the maintenance of separate "rate zones" for ratemaking purposes but Alectra Utilities is the actual corporate entity.

SEC argued that it was important for the OEB to send a clear message that ICM funding is not a back door way to increase rates, but is an exception to the normal rule of living within the IRM envelope and is not an invitation to spend more. SEC submitted that ICM funding is a relief valve where utilities have done everything they can to live within their

[28] Toronto Hydro-Electric System Limited, "Partial Decision and Order," EB-2012-0064, April 2, 2013.
[29] Funding of Capital Report, p.17.

means, but that Alectra Utilities had made no attempt to do so, and therefore should be expected to live within the IRM envelope.

Alectra Utilities submitted that the project-specific materiality threshold is defined by the OEB as 0.5% of distribution revenue requirement, in accordance with the Chapter 2 Filing Requirements.[30] Alectra Utilities calculated the threshold amount for each rate zone on this basis and included projects that exceeded the identified thresholds.

### Findings

The OEB accepts Alectra Utilities' calculations for the ICM materiality threshold based on the OEB's ICM formula in the Funding of Capital Report. This includes:

- Brampton RZ - maximum eligible incremental capital amount of $7,113,613
- PowerStream RZ - maximum eligible incremental capital amount of $25,891,795
- Enersource RZ - maximum eligible incremental capital amount of $39,624,419

This does not mean that all capital spending up to the maximum eligible incremental capital amount will be granted incremental funding. The OEB has established its other criteria and tests so that the ICM does not become just a top-up to the ICM materiality threshold.

The OEB does not agree with SEC that a distributor must have done everything it can to live within its means. The ICM is not a mechanism to ensure the financial viability of a distributor. The ICM is a mechanism that removes a barrier to effective planning by providing rate relief to reduce the incentive to cluster capital investments at sub-optimal times around the rebasing year. A distributor is expected to have good distribution system planning, including optimizing, prioritizing and pacing capital expenditures to control costs and promote rate predictability, irrespective of its rebasing schedule.

The OEB disagrees with Alectra Utilities' interpretation of the second materiality test. The distributor in this ICM application is Alectra Utilities. This second test is whether a specific project is significant in comparison to the overall capital budget for Alectra Utilities, not individual rate zones. With Alectra Utilities' interpretation, a large distributor with a capital budget of hundreds of millions of dollars could acquire a small distributor

[30] Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 2 Cost of Service.

and seek ICM funding for a project of only $50,000. This would not be a reasonable request.

The OEB notes that the MAADs policy states that: “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”.[31] The OEB finds that this statement is not relevant to the assessment of project-specific materiality. The reference to depreciation expense in the MAADs policy makes it clear that this policy statement pertains to the ICM materiality threshold formula that is calculated based on depreciation, not the project-specific materiality test that is based on a comparison of an expenditure to the overall capital budget.

Applying the Chapter 2 Filing Requirements materiality threshold test to Alectra Utilities as the distributor would result in a project-specific materiality threshold of $1 million to be applied across all rate zones. However, the OEB finds that the Chapter 2 Filing Requirements materiality threshold test is not the project-specific test set out in the ICM policy. The materiality thresholds in the Chapter 2 Filing Requirements[32] are for the purpose of variance explanations for annual changes to rate base, capital expenditures and operations, maintenance and administration costs as part of a cost of service rate application. Consistent with this purpose, the materiality threshold for the variance analysis is calculated from the revenue requirement. The project-specific materiality, per the ICM policy, is based on the capital budget.

The OEB recognizes that in an Enersource decision,[33] the OEB accepted the project-specific materiality calculated by Enersource based on 0.5% of revenue requirement. This was a project specific calculation of $0.59 million for an ICM approved of $40.5 million. There was no question that this project was not a minor expenditure in comparison to the overall capital budget i.e. the project specific calculation was not required to make the determination that this project was significant. The OEB does not find that the Enersource decision established a new condition precedent for future ICMs.

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[31] “Report of the Board Rate-Making Associated with Distributor Consolidation,” EB-2014-0138, March 26, 2015, p. 10.
[32] Section 2.0.8.
[33] Decision and Rate Order “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”, EB-2015-0065, April 7, 2016.

In the Funding of Capital Report, the OEB adopted the approach for the ICM policy established in the Toronto Hydro decision which stated that: "minor expenditures in comparison to the overall budget" should not be considered eligible for ICM treatment.[34] The Toronto Hydro decision emphasized that the overall capital budget is the reference point for assessing the significance of ICM requests. The OEB determined that a: "certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget", and this wording was included in the materiality criteria for an ICM. This decision disallowed ICM funding for several projects with capital spending in excess of $1 million, including a project with $2.14 million in capital expenditures and $1.68 million in capital additions. The decision stated that while the OEB accepted the need for the work: "the amount requested is not significant in the context of THESL's overall capital budget. THESL should be able to fund this project through its normal capital budget during the IRM period, and will not be permitted additional recovery for this project".[35]

The OEB finds that the basis for a project-specific materiality threshold should be the proposed capital budget of Alectra Utilities, the distributor in this ICM application. Adding the 2018 capital budgets for each rate zone results in a combined capital budget of $267.7 million.[36] While one could consider a percentage of the $267.7 million to be appropriate for the project-specific materiality test, the OEB finds that this is not consistent with the ICM policy. The ICM policy adopted the approach used in the Toronto Hydro decision, which assessed each project individually for its significance against the capital spending. The OEB therefore adopts this same approach for the ICMs for Alectra Utilities. Amending the ICM policy to include a mathematical materiality calculation for this second test should only be done through a policy review. In addition, there were no submissions on this issue during the proceeding. The OEB has applied its judgement consistent with the ICM policy. The OEB will consider whether each capital project proposed for an ICM is significant with respect to Alectra Utilities' total capital budget, not with respect to the capital budget by rate zone.

While the second materiality test may be further defined in the future, the OEB must make a decision based on the evidence and submissions in this proceeding. The OEB

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[34] Funding of Capital Report, p.17.
[35] EB-2012-0064 Toronto Hydro Decision, several projects were not approved for funding for being not significant in the context of the overall capital budget (pages 31, 32, 39, 41, 42), one example is the Downtown Station Load Transfers, pages 41 and 42 with capital spending of $2.14 million and capital additions of $1.68 million.
[36] $267.668 million = $72,683 (Enersource) + $109,773 (PowerStream) + $38,069 (Brampton) + $47,143 (Horizon Utilities EB-2014-0002 Settlement Table 18 – 2018 Capital Expenditure Plan).

is guided by the words “significant influence on the operation of the distributor” and “minor expenditure in comparison to the overall capital budget” in assessing the project-specific materiality of each project.

The assessment of each specific project is in subsequent sections of this Decision.

*Need*

The Funding of Capital Report indicated that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, and should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[37]

Under the Means Test, if a distributor’s regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor’s rates, then the funding for any incremental capital project would not be allowed. Alectra Utilities submitted that based on the accounts of its predecessor utilities, it had satisfied the Means Test in each rate zone.

No party took issue with Alectra Utilities passing the Means Test.

Alectra Utilities submitted that each proposed ICM project is discrete and that it had performed detailed, project-specific cost estimates based on a specific scope of work and detailed design carried out for a particular location.

Furthermore, Alectra Utilities stated that the costs of the projects for which it is seeking recovery are incremental to its capital requirements that underpin its existing rates for each rate zone.

The distinction between a discrete project versus a program was raised in many submissions.  AMPCO stated that it did not accept Alectra Utilities’ distinction between a project and a program as all of the restructured initiatives have historically been part of typical annual capital programs and should not be approved. In particular, AMPCO noted that in the PowerStream RZ, 30% of the projects were disallowed by the OEB in its Custom IR decision.

CCC argued that with very few exceptions (transit projects), the proposed expenditures are essentially a continuation of normal annual capital programs, not discrete

[37] Funding of Capital Report, page 17.

incremental capital projects, and Alectra Utilities should have sufficient funds to undertake all of its required capital investments through its price cap adjustments.

### Findings

The OEB finds that Alectra Utilities has passed the Means Test. Alectra Utilities provided evidence with respect to the earnings by rate zone. The OEB finds this is acceptable for assessing the earnings the year prior to merger, i.e. 2016. This test is, however, established to determine if a distributor requires funding in advance of the next rebasing. Earnings are therefore more appropriately assessed for the distributor, not the rate zone.

In addition, the OEB finds that a discrete project is not simply one that is distinguishable or defined at a new location - or all capital would be eligible. ICM projects do need to be different in kind from those that are carried out through typical base capital programs. Otherwise, the OEB would need to scrutinize all capital projects for optimization, not just the ICM projects. Further, the criteria in the ICM policy is clear that capital projects do not need to be non-discretionary[38] or unanticipated to be eligible for incremental funding.

The OEB finds that it is not relevant whether the capital project proposed for ICM treatment was included in a previously filed DSP. Requiring a project to have been included in a previous DSP would be re-introducing the requirement for projects to be unanticipated, which the OEB previously eliminated. In addition, there is no criteria excluding capital projects that were denied funding in a previous cost of service or ICM application. Circumstances may change with respect to load, demand, cost estimates or consumer preferences that affect the business case and the needed timing of the project.

*Prudence*

The Funding of Capital Report specifies that the amounts to be incurred must be prudent, which means that a distributor’s decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[39]

Alectra Utilities submitted that its eligible capital projects are prudent because in the case of the Brampton RZ, the project is non-discretionary in nature, while for the

[38] Funding of Capital Report, pp.18-19.
[39] Ibid, p. 17.

PowerStream and Enersource RZs, the projects represent the most cost effective options for ratepayers.

Alectra Utilities added that in each case, the projects are based on capital investment needs for the three rate zones for 2018 that are not funded through existing distribution rates.

Alectra Utilities submitted that to demonstrate the prudence of each capital project for which it is seeking approval, it had provided a business case summary that identifies the name, driver, cost and expected in-service date for the project, describes the project and its drivers, and sets out the various options considered for the project. In addition, Alectra Utilities stated that it had provided detailed business cases for each eligible capital project.

OEB staff argued that most of the ICM projects were not distinguishable from other expenditures that were part of normal year-to year capital programs for the rate zones.

Intervenors argued that it is not possible to determine prudence in the absence of cost information on alternative options. Alectra Utilities identified that it did provide cost estimates for alternative options for the majority of projects. Cost estimates were not provided for alternative options when the alternative options would not provide the required capabilities or meet applicable technical standards. Alectra Utilities also argued that conservation and demand management (CDM) is not an alternative for system renewal investments.

AMPCO, VECC and CCC submitted that the OEB should not approve the 2018 ICMs until Alectra Utilities has prepared a consolidated DSP.  These intervenors submitted that one combined DSP would optimize need and spending across all rate zones to provide the greatest value to customers, for a merged entity with four rate zones.

AMPCO also noted that the PowerStream RZ’s 2018 proposed capital budget is below the 2017 OEB approved budget, meaning that it should be able to accommodate the 2018 capital spend within the 2018 Price Cap IR adjustment.

VECC argued that for the PowerStream RZ, Alectra Utilities had not met the burden of proof as to the need for these projects, other than a rapid transit project,  because it had not explained how these projects were (or were not) contemplated in its DSP.

Alectra Utilities argued that the OEB was well aware that Alectra Utilities would not be in a position to file a consolidated DSP until 2019. Alectra Utilities concluded that it is simply wrong to say that a consolidated DSP is required before it is eligible for ICM funding.

**Findings**

The availability of an ICM to Alectra Utilities was neither predicated on filing a consolidated DSP, nor limited to one ICM application for the deferred rebasing period.

While a consolidated DSP is not a prerequisite to filing an ICM, the OEB acknowledges the concerns expressed by intervenors and OEB staff that the value of the current DSPs for Alectra Utilities will diminish long before the 10-year deferral period has ended. The OEB accepts these limitations for 2018, and 2019 rates if required. It would not have been reasonable to expect a new fully integrated and consolidated DSP for this proceeding. The OEB finds that the prior DSPs are sufficient for the OEB to review and decide on capital projects for this proceeding.

The MAADs decision noted that Alectra Utilities would not be in a position to file a consolidated DSP until 2019, applicable to 2020 rates. The OEB finds this proposal reasonable. The OEB requires Alectra Utilities to file a consolidated DSP as a filing requirement with any ICM application requesting rate changes for 2020 rates and beyond.

Providing an assessment of options to meet an identified need is an important element of an application for funding of capital, whether it be in a rebasing application or for an ICM. The OEB accepts that costing and detailed analysis of an option is not required if an option does not meet the required capabilities or applicable technical standards. The OEB does not accept Alectra Utilities' assertion that CDM is not an alternative for system renewal investments options. Like-for-like asset replacements for aging infrastructure should not be the only option considered. Circumstances may have materially changed since an asset was first put into service. As a result, new options, including those that do not involve distribution infrastructure, should be considered when Alectra Utilities prepares its consolidated DSP.

The OEB recognizes that because the ICM materiality threshold formula is based on the ratio between a utility's approved rate base and depreciation, it can lead to circumstances in which there is eligible ICM capital even though the capital spending in the year of the ICM is lower than the last OEB-approved capital spending. While this does not disallow an ICM outright, this is a consideration when determining whether a project is significant to operations, and outside of the base upon which the rates were derived.

### b) Eligibility of Individual Projects for ICM Recovery

Alectra Utilities requested total ICM funding of $56.18 million. Alectra Utilities provided the table reproduced as Table 2 below summarizing the proposed ICM projects by rate zone.[40]

The OEB agrees that it is important for a distributor to have programs to address aging infrastructure to ensure assets are replaced on a paced and prioritized schedule. Nevertheless, this application is about whether incremental funding for capital will be provided during the IRM term. ICM funding is not available for typical annual capital programs. It is also not available for projects that are not significant to the operations of the distributor. Where the OEB has not approved a project for incremental funding, this should not be interpreted as the OEB saying that it is not prudent to complete the project.

The OEB assessed each proposed project on an individual basis against the criteria from Section 4.5 a) of this Decision. The OEB approves total ICM funding of $28.79 million as discussed in the individual sections that follow.

[40] Alectra Utilities, “Applicant’s Reply Submission”, January 30, 2018, pp. 22-23.

### Table 2: Projects Proposed for ICM Recovery

| CATEGORY | PROJECT | 2018 BUDGET |
|---|---|---|
| **BRAMPTON RZ** | | |
| System Access | 1. Pleasant TS True-Up | $6.8MM |
| **POWERSTREAM RZ** | | |
| System Access | 1. York Region Rapid Transit VIVA Bus Rapid Transit Y2 and H2 Projects | $11.24MM |
| System Renewal | 2. Station Switchgear Replacement - 8th Line MS323 | $1.39MM |
| | 3. Rear Lot Supply Remediation - Royal Orchard - North | $1.68MM |
| | 4. Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive | $1.84MM |
| | 5. Cable Replacement – (V08) - Steeles Ave and New Westminster | $2.64MM |
| | 6. Circuit Breaker Replacement – Richmond Hill TS#1 | $1.19MM |
| System Service | 7. Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie | $1.37MM |
| | 8. Mill St. MS835 Transformer Upgrade – Tottenham | $1.3MM |
| | 9. Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview | $1.2MM |
| | 10. Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 | $1.28MM |
| **ENERSOURCE RZ** | | |
| System Access | 1. QEW – Evans to Cawthra Roads Project | $1.29MM |
| System Renewal | 2. Glen Erin & Montevideo Subdivision Rebuild | $1.96MM |
| | 3. Glen Erin & Battleford Subdivision Rebuild | $2.06MM |
| | 4. Credit Woodlands & Wiltshire Subdivision Rebuild | $1.55MM |
| | 5. Tenth Line Main Feeder Subdivision Renewal | $1.14MM |
| | 6. Folkway & Erin Mills Main Feeder Subdivision Rebuild | $1.03MM |
| | 7. City Centre Drive Rebuild (Walmart Cables) | $1.55MM |
| | 8. Lake/John Area Overhead Rebuild | $0.93MM |
| | 9. Church St. Area Overhead Rebuild | $1.02MM |
| | 10. Transformer Replacement Project | $8.45MM |
| System Service | 11. York MS | $3.27MM |

### Brampton Rate Zone

Alectra Utilities proposed one ICM project in the Brampton RZ for $6.8 million. The OEB approves ICM funding for this project.

*1. Brampton RZ Pleasant TS True-Up $6.8 million*

Alectra Utilities stated that this investment was required under the terms of the Connection and Cost Recovery Agreement (CCRA) between itself and Hydro One Networks Inc. (Hydro One) for the construction of the Pleasant TS expansion in the Brampton RZ. Alectra Utilities noted that the CCRA was entered into by the former Hydro One Brampton, in connection with its efforts to increase available transformation capacity for anticipated load growth in the northwest area of Brampton. Alectra Utilities further noted that the ten-year true-up payment under the CCRA is due in June 2018 and it estimated a shortfall of revenue to Hydro One relative to the forecast demand used to calculate the capital contribution initially. Alectra Utilities therefore anticipates being required by Hydro One, under the terms of the CCRA, to provide a further contribution of $6.8 million in June 2018, with the specific amount and payment terms to be finalized at that time.

OEB staff and the PWU supported Alectra Utilities' proposed recovery related to this project while all other parties were opposed to it.

Intervenors opposed to this proposal made four major arguments against it which were: (1) the inaccuracy of the original load forecast on which the arrangements were determined, (2) the CCRA governing the true-up payment between Hydro One Brampton and Hydro One was not an arms-length transaction, (3) Hydro One Brampton's liability for the true-up was not disclosed in the merger proceeding and should have been addressed at that time, and (4) the cost of the ten-year true-up payment under the CCRA was not included in the DSP and is not incremental to historic spending levels. Alectra Utilities submitted that none of these arguments had any merit.

**Findings**

The OEB approves the project for $6.8 million of ICM funding, effective May 1, 2018, related to the Pleasant TS true-up payment to Hydro One.

The expenditures on this project are for a "true-up" contribution to cover the cost differential between the load forecast and actual load serviced from the new transformer station at Pleasant TS. The true-up payment is in accordance with the terms of a CCRA with Hydro One, and the CCRA must be in accordance with the OEB's Transmission System Code (TSC). The TSC establishes pre-set true-up milestones at 5, 10 and 15 years. The OEB accepts the evidence that there was an economic downturn in Ontario and load did not materialize as forecast, and that this impacted housing starts and electricity demand for loads serviced from Pleasant TS. The evidence does not support a finding that Hydro One Brampton was imprudent in the forecast made for the purpose of the CCRA executed in 2006.

The OEB notes that the five-year true-up payment for the Pleasant TS was discussed in the DSP for Hydro One Brampton's 2015 rate application.[41] A true-up amount of $3.653 million paid in 2014 was approved by the OEB for inclusion in the 2015 rate base. The OEB accepts that Hydro One Brampton did not know at the time whether another true-up payment would be required five years later.

While the CCRA was between the affiliates of Hydro One Brampton and Hydro One, the terms of the CCRA are prescribed by the TSC. The OEB finds that this affiliate relationship is not grounds for denying the ICM.

The CCRA was entered into on behalf of the customers of Hydro One Brampton at the time. The OEB finds that if there had been no merger, the Pleasant TS true-up payment would have been recoverable from Hydro One Brampton customers. It is therefore appropriate post-merger for the true-up payment to be recoverable from customers of Alectra Utilities' Brampton RZ. Whether there was a liability to disclose at the time of the merger, or not, does not impact which customers should pay for the true-up payment.

This ICM request is similar to the ICM application from Enersource Hydro related to the Churchill Meadows TS, which the OEB approved.[42] In that earlier application, the OEB found that the true-up payment to Hydro One met the three ICM criteria.

### PowerStream Rate Zone

Alectra Utilities proposed ten ICM projects in the PowerStream RZ, including one system access project of approximately $11.2 million, five system renewal projects totaling approximately $8.7 million and four system service projects totaling approximately $5.2 million, for an overall total of approximately $25.1 million. The OEB approves ICM funding of $11.24 million, effective May 1, 2018.

[41] EB-2014-0083.
[42] EB-2015-0065.

*2. PowerStream RZ York Region Rapid Transit VIVA Bus Rapid Transit Y2 and H2 Projects $11.24 million*

This project involves the relocation of overhead and underground distribution assets as required to accommodate York Region Rapid Transit Corporation's (YRRT) Bus Rapid Transit ("BRT") developments. Alectra Utilities stated that:

- The timing for this work is driven by the YRRT in conjunction with its contractors.
- The project, which includes development of BRT rapidways, is a key component of York Region's Transportation Master Plan.
- Two sections along Yonge Street totaling 6.5 km (Y2) and two sections along Highway 7 and adjacent roadways totaling 8.5 km (H2) are scheduled for completion in 2018 and 2019. Each of Y2 and H2 involves major thoroughfares with significant overhead and underground distribution plant (including 27.6 kV feeders), which must be relocated before the rapidways can be built.
- It is required to relocate its distribution plant to facilitate transportation infrastructure developments by applicable road authorities in accordance with the *Public Service Works on Highways Act*. Therefore, Alectra Utilities states that this project is considered mandatory.

SEC, VECC, CCC, AMPCO and BOMA opposed ICM treatment for this project. OEB staff and PWU supported approval for recovery of the full amount proposed.

The parties opposing approval argued that it should be treated in the same way as the Metrolinx rail electrification projects, namely by establishing a deferral or variance account to record actual costs for future review and recovery. These parties argued that there is inherent uncertainty with government-backed infrastructure projects, and that this is common to the Metrolinx and road authority projects. SEC stated that a variance account should only be used to the extent that capital additions for the PowerStream RZ exceed the 2017 OEB-approved capital additions of $115 million. Several parties also argued that this is recurring annual capital work and should therefore not be eligible for ICM recovery.

### Findings

The OEB approves the YRRT project for ICM funding of $11.24 million effective May 1, 2018. The work is mandatory under the *Public Service Works on Highways Act*.

As discussed in section 4.8 d) of this Decision, the OEB has adopted the ICM for incremental funding for capital projects. The OEB therefore does not approve a deferral account for this project, as suggested by some intervenors.

Alectra Utilities states that assets will be in service in 2018 and purchase orders have been signed. Any uncertainty risk of the project is mitigated because the magnitude of in-service assets for 2018 will be reviewed at the time of rebasing to determine if a true-up between the approved amount of $11.24 million and actual in-service assets is warranted.

While a utility the size of Alectra Utilities is expected to undertake a certain amount of relocations each year, this project is clearly very material to its operations. The project was only identified after the PowerStream Custom IR application was filed.

*3. PowerStream RZ Station Switchgear Replacement – 8$^{th}$ Line MS323 $1.39 million*

The Station Switchgear Replacement - 8th Line MS323 project involves replacement of low voltage switchgear at the 8th Line MS 323 station, which has been assessed as being in poor condition, at a high risk of failure and no longer supported by the manufacturer. Alectra Utilities stated that:

- The switchgear needs to be brought to current standards with respect to arc-resistant construction to reduce safety concerns.
- The station serves approximately 2,700 customers and the project is expected to extend the useful life of the station as well as avoid 97,200 customer outage minutes per year, which would have otherwise affected 900 residential and commercial customers.
- The replacement switchgear will not fit in the existing enclosure at the station so a new switchgear building will be required. A prefabricated switchgear building will be used to reduce outage time for construction.

PWU supports approval of the amount proposed, while SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, are opposed.

OEB staff argued that a number of Alectra Utilities’ proposed projects are relatively small and that minor expenditures should be excluded from recovery through the ICM mechanism.

AMPCO and CCC argued that the project is not discrete and involves work that is similar in nature to recurring annual capital work and that it is not possible to determine if the recommended approach is prudent because cost information on alternative options was not provided.

Alectra Utilities argued that projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

In response to the contention that it is not possible to determine prudence in the absence of cost information on alternative options, Alectra Utilities identified that retrofit of existing switchgear was considered and determined not to be feasible as this would not address the arc-resistant capability required for safety purposes. As this option did not address the identified need, it was not priced.

**Findings**

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to funding this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

The OEB also notes that in its decision on the PowerStream Custom IR application, funding was approved for a switchgear replacement program.[43] This work replacing switchgear at the 8th Line MS 323 station would reasonably be part of such a program. ICM funding is not available for typical annual capital programs.

*4. PowerStream RZ Rear Lot Supply Remediation – Royal Orchard – North $1.68 million*

Alectra Utilities stated that the rear lot distribution system in the area of Royal Orchard – North serves approximately 170 customers, is over 50 years old, has been assessed as being in very poor condition and is beyond the end of its useful life. Alectra Utilities stated that:

[43] Decision and Order "PowerStream Inc. Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020," EB-2015-0003, August 4, 2016, p.17.

- Rear lot systems are more likely to be affected by major events such as storms.
- Due to accessibility problems, restoration is very difficult and costly.
- Rear lot systems pose safety risks to workers.
- Tree trimming is often required before crews can safely access equipment, and proximity to customer facilities inhibits access and introduces safety risks.
- There are operational inefficiencies when working on rear lot systems as well because most work must be performed without use of bucket trucks and modern hydraulic equipment.
- Work on rear lot systems requires access to multiple yards, and tree trimming must be performed more frequently.

Alectra Utilities proposed to convert the area of Royal Orchard – North to front lot underground supply over a three-year period from 2018 to 2020, which it states is the most effective option to eliminate the above-noted concerns and improve reliability by reducing outage minutes by approximately 110,000 minutes per year (not considering major event days).

PWU supported approval for recovery of the full amount proposed. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment for this project.

AMPCO and CCC argued that this project is not discrete and involves work that is similar to ongoing annual capital work. In addition, a determination regarding prudence cannot properly be made without cost information on the alternative options to the recommended project.

OEB staff argued that this project does not meet the prudence criteria due to Alectra Utilities' failure to provide sufficient costing information to address the OEB's concerns from the PowerStream Custom IR decision and to demonstrate that the proposed expenditures represent the most cost-effective option for ratepayers.

OEB staff and VECC also argued that there were deficiencies in the customer engagement efforts relating to this project because Alectra Utilities did not speak with the affected customers directly and did not indicate what feedback was received.

## Findings

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding.

In the PowerStream Custom IR application, the OEB approved funding for a rear lot supply remediation program.[44] This work converting the area of Royal Orchard – North to front lot underground supply is reasonably part of such a program.

Furthermore, the OEB's decision in the PowerStream Custom IR application specifically identified concerns with respect to adequate customer engagement for the rear lot remediation program stating: "It is striking that PowerStream testified it visited every affected rear lot, but did not speak to any of the owners of those lots, who would experience both a reliability impact and disruption to the use of their property".[45] It appears that Alectra Utilities has still not engaged directly affected customers in the development of its plans for rear lot remediation.

*5. PowerStream RZ Cable Replacement – (M49) – Steeles Ave and Fairway Heights Drive $1.84 million*

The Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive project involves replacing 3.7 km of substandard underground primary cables. Alectra Utilities stated that:

- Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016.
- In this project area, the underground primary cable is 35 years old, has been assessed as being in poor condition and is at the end of its useful life.
- This project area is also one of the few remaining pockets of 13.8kV load supplied from John MS, via feeders John-F5 and John-F6. The performance of these feeders is many times worse relative to the SAIFI and SAIDI for the service

[44] EB-2015-0003, op.cit. p. 20.
[45] EB-2015-0003, op.cit. p. 19.

territory. John-F5 is among the top 10 worst performing feeders out of the 322 feeders in the PowerStream RZ.

- Given the reliability concerns and higher losses associated with the 13.8kV system, the majority of 13.8kV load in this area has been converted to 27.6kV. Once all 13.8kV load is converted to 27.6kV, John MS can be decommissioned, thereby avoiding the costs of operating and maintaining an underutilized station.
- This project is expected to result in 81,480 outage minutes avoided per year and lower transformer and distribution line power losses.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

OEB staff referenced the OEB's decision on the Custom IR application where the OEB expressed concerns with cost increases associated with the underground cable replacement program and asked PowerStream to explain the reasons for the increase in unit costs over time at its next rate setting opportunity.

Alectra Utilities[46] explained that following the OEB's decision it reviewed its cable replacement program and determined that each cable replacement would thereafter be treated as a distinct project with a defined scope, schedule and cost to address a specific driver because doing so would bring greater rigour, discipline and accountability to project planning and implementation. OEB staff argued that this response did not adequately address the concern expressed by the OEB in the Custom IR decision, and that these projects do not satisfy the prudence criteria due to insufficient costing information to demonstrate that the proposed expenditures represent the most cost-effective option for ratepayers. This latter concern was echoed by AMPCO and CCC.

In addition, OEB staff and VECC raised concerns about the adequacy of customer engagement with respect to the cable replacement projects.

Alectra Utilities explained that based on the restructured approach to these cable replacements it forecast cost reductions of 28% for cable replacements and 11% for its Left Behind Cable Replacement initiative.[47]

In response to the concern that there is insufficient costing information, Alectra Utilities noted that the main alternative to a cable replacement is cable injection. However,

[46] PRZ-Staff-7.
[47] 3.0-VECC-16.

injection is not always feasible. In the cable replacement project at Steeles Avenue and Fairway Heights, the existing cables are 8.32 kV and, as a result, injection would not align with plans to convert the area to 27.6 kV. If injected, the cables would soon need replacement and the costs of injection would become stranded. Alectra Utilities added that conversion to 27.6 kV brings numerous benefits, such as lower maintenance costs and reduced losses.

Alectra Utilities further noted that it had only provided costing for alternative feasible options that would meet the identified project needs.

**Findings**

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding.

In its decision on the PowerStream Custom IR application[48] the OEB approved funding for a cable replacement program. This work replacing cables in the Steeles Ave and Fairway Heights Drive area is reasonably be part of such a program.

Alectra Utilities has stated that following the OEB's decision for its Custom IR application it determined that each cable replacement would be treated as a distinct project. The OEB finds that simply developing more details on the specific work planned within a typical annual capital program does not create multiple discrete projects eligible for ICM funding.

*6. PowerStream RZ Cable Replacement –(V08) – Steeles Ave and New Westminster $2.64 million*

The Cable Replacement – (V08) - Steeles Ave and New Westminster project involves replacing approximately 16.2 km of substandard underground primary cables from 2018 to 2020. Alectra Utilities stated that:

- Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016.

[48] EB-2015-0003, op.cit. p. 17.

- In this project area, the underground primary cable supplies 1,090 customers, is approximately 40 years old, has been assessed as being in very poor condition and is at the end of its useful life. It has failed nine times in the last four years, resulting in over 350,000 customer outage minutes.
- This project is expected to improve system reliability in the area, minimize the need for emergency reactive repairs and result in 109,998 outage minutes avoided per year.

The intervenors and OEB staff made the same submissions for this project as they did for the cable replacement project for Steeles and Fairview. Alectra Utilities responded accordingly. In addition, Alectra Utilities noted that cable testing results indicated that remediation by cable injection would not be feasible.

**Findings**

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding.

In its decision on the PowerStream Custom IR application[49] the OEB approved funding for a cable replacement program. This work replacing cables in the Steeles Ave and New Westminster area is reasonably part of such a program.

Alectra Utilities has stated that following the OEB's decision on the PowerStream Custom IR application it determined that each cable replacement would be treated as a distinct project. The OEB finds that simply developing more details on the specific work planned within a typical annual capital program does not create multiple discrete projects eligible for ICM funding.

*7. PowerStream RZ Circuit Breaker Replacement – Richmond Hill TS#1 $1.19 million*

The Circuit Breaker Replacement – Richmond Hill TS#1 project involves replacing the six existing circuit breakers at Richmond Hill TS#1 due to technological incompatibility, a history of failures and the fact that manufacturer support is no longer being provided for this equipment. The project also includes procurement of one spare circuit breaker.

[49] Ibid.

Alectra Utilities stated that the most recent failure involving this type of circuit breaker at this station affected 15,500 customers and took over two hours to fully restore service. A forensic analysis, undertaken by Kinectrics, determined that the transient recovery voltage ("TRV") rating of this type of breaker is inadequate for this station. The TRV rating is a critical parameter for fault interruption by a circuit breaker and the forensic analysis points to the fact that the inadequate TRV ratings will result in further and more costly unplanned breaker failures if not resolved in a planned manner. Alectra Utilities expects the project to improve reliability, reduce the likelihood of customer interruptions and enable cost savings through the planned removal of obsolete equipment and standardization.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

### Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

*8. PowerStream RZ Rebuild of 27.6 kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie $1.37 million*

The Rebuild of 27.6 kV Pole Line on 1 Warden into 4 Circuits from 16th Ave to Major Mackenzie project involves replacement of the existing two feeder 27.6 kV pole line on Warden Avenue with a four feeder pole line, extending existing feeders 12M10 and 12M11 into Markham North and increasing supply capacity by 40 MVA with two new feeders. Alectra Utilities stated that there are known large commercial facilities coming online in 2018 that will add 9.5 MVA of new load, which will use up all available capacity on the two current feeders. Beyond 2018, projected growth associated with long-term area developments is expected to require 66 MVA of additional capacity, as a result of the North Markham Future Urban Area expansion, and further load growth due to the Highway 404 North Development. Alectra Utilities argued that without this investment, the existing feeders will be fully loaded in 2018 and the ability to restore power during feeder outages will be very limited.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

## Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

The OEB also notes that a driver for this work is load growth in the area that will bring in additional revenue to Alectra Utilities. This additional revenue from growth will reduce the financial impact on the operations of the utility.

### *9. PowerStream RZ Mill St. MS835 Transformer Upgrade – Tottenham $1.3 million*

The Mill St. MS835 Transformer Upgrade – Tottenham project involves an upgrade of the Mill MS835 6 MVA transformer in order to provide the necessary backup capacity to meet load growth anticipated by 2019. Alectra Utilities stated that:

- Three major residential developments, scheduled to be completed over the next four years in this area, are expected to add 1,300 new customers.
- This growth will result in an additional 2.7 MVA of peak load supplied by two stations by 2019, bringing the total loading of the two stations to 9.6 MVA.
- This will exceed the emergency capacity of Mill MS835 (9.1 MVA) to provide backup in the event of failure at the Nolan MS834 station.
- Load is expected to continue to rise beyond 2019, reaching 12 MVA by 2025/26.
- This project is the most effective way to address the increased capacity requirements, as well as reliability, under single contingency scenarios.

PWU supported the project. BOMA also expressed its support for this project as it is: (1) distinct, (2) not part of pre-existing programs, and (3) alternatives were thoroughly canvassed.

SEC, VECC, CCC and AMPCO, as well as OEB staff, did not support ICM treatment.

### Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

The OEB also notes that a driver for this work is load growth in the area that will bring in additional revenue to Alectra Utilities. This additional revenue from growth will reduce the financial impact on the operations of the utility.

*10. PowerStream RZ Double Circuit 27.6 kV Pole Line on 19th Ave between Leslie and Bayview $1.2 million*

The Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview project involves construction of a double circuit pole line and extension of two 27.6kV circuits onto 19th Ave from Leslie St. to Bayview Ave. to meet significant growth in this area. Alectra Utilities anticipates that approximately 500 new homes will require connection to the distribution system in the area. Alectra Utilities stated that there are no feeders on 19th Ave between Leslie and Bayview to support residential or commercial developments, therefore, new load in the development area cannot be serviced unless feeders are installed to connect the new customers.

Alectra Utilities further stated that a secondary driver stems from the radial configuration of the existing feeder on Leslie St, which means power is supplied from one end of the feeder only. There is no alternate supply from any other source in the event of an outage, thus giving rise to risks of prolonged outages. Alectra Utilities argued that this issue will become more significant as the customer density in the area continues to increase.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

### Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

*11. PowerStream RZ Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 $1.28 million*

The Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 project involves the extension of feeder 23M28 along the existing path of 23M21 from Bayfield St. and Livingstone St. to Cundles Rd. and Duckworth St., and transfers the supply of Little Lake MS306 from 23M21 to 23M28. Alectra Utilities stated that:

- This project will free up capacity on 23M21 to meet projected load growth, supply the new Livingstone MS310 and mitigate the existing thermal overloading issue under contingency conditions for the area.
- Transferring the supply of Little Lake MS306 to the 23M28 and supplying the new Livingstone MS310 from 23M21 will more evenly distribute load across both feeders.
- Contingency transfers from 23M21 will be accommodated by both the existing 23M6 and new feeder 23M28.
- The new circuit will require a rebuild of the existing pole line along Livingstone St (from Bayfield St. to Cundles Rd.) and along Cundles Rd. to Little Lake.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

**Findings**

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to funding this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

## Enersource Rate Zone

Alectra Utilities proposed eleven ICM projects in the Enersource RZ. These include one system access project of approximately $1.3MM, nine system renewal projects totaling approximately $19.7MM and one system service project totaling approximately $3.2MM, for an overall total of approximately $24.2MM.

The OEB approves ICM funding of $10.754 million, effective May 1, 2018.

*12. Enersource RZ QEW – Evans to Cawthra Roads Project $1.29 million*

The Evans to Cawthra Roads project is required by legislation to relocate electrical infrastructure to accommodate road work, as well as the final "cloverleaf" ramp configuration, arising from the Ministry of Transportation of Ontario's (MTO's) redesign of the on and off ramps at Dixie Road and QEW. Alectra Utilities stated that:

- Timelines for the execution of the road works are driven by the Region of Peel, City of Mississauga, and the MTO.
- This mandatory project involves removal of 39 poles, relocation of 72 poles, installation of 3 temporary poles, as well as implementation of an underground crossing of the QEW.
- The MTO will contribute all costs related to the relocation of assets on municipal property, and share costs on a 50/50 basis for asset relocations on MTO lands.

OEB staff and the PWU supported approval for recovery of the full amount proposed.

SEC, VECC, CCC, AMPCO and BOMA did not support ICM treatment for this project.

The parties opposing the project argue fundamentally, that it is comparable to other ongoing capital work programs. AMPCO argued that other cable and pole replacement projects should be deferred to accommodate the QEW – Evans to Cawthra Roads Project instead of approving incremental funding. AMPCO also argued that this project is similar to the Creditview road widening project, which is in the base budget.

Alectra Utilities disagreed with AMPCO because the other projects are to replace poles in poor condition and this project is required due to the MTO's roadwork. Alectra Utilities responded that this is ranked seventh and the Creditview project is ranked eighth.

**Findings**

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

Utilities are routinely required to relocate electrical infrastructure to accommodate roadwork by the MTO, a municipality or other road authority. Legislation has been enacted for this requirement and how to apportion costs. This work should be funded through base capital programs unless a project is significant to the operations of the utility.

*13. Enersource RZ Glen Erin & Montevideo Subdivision Rebuild $1.96 million*

The Glen Erin & Montevideo Subdivision Rebuild project involves renewal and replacement of early generation underground distribution cables and eight padmount transformers in the project area. Alectra Utilities stated that:

- Increasing failures on early generation underground cables (which are mostly unjacketed, i.e. without a protective sheath, and/or direct buried) are leading to rising numbers of outages and having an adverse impact on reliability.
- Since 2013, SAIDI and SAIFI in the project area have been four times and two times greater than the three year system average, respectively. Customers in this area have experienced two outages every year for the last three years due to these specific assets alone.
- The cables and transformers in the area are approximately 40 years old and are beyond the end of their useful life.
- This project is the preferred solution as it provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.
- The new cables will be installed in PVC ducts to make future replacement much less costly and will meet current standards for residential underground distribution.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment.

Parties opposing the proposed cable replacement projects argue that they are not unique relative to other underground cable replacement projects, that they involve normal capital expenditures and these projects are comparable to or part of routine ongoing work programs.

OEB staff further argued that the prudence and need criteria have not been met because Alectra Utilities has not shown an urgent driving need for these projects, and there is evidence that one of the important historical causes for underground cable failures has now been effectively mitigated.

Alectra Utilities submitted that the cable replacement projects are targeted to areas with high levels of cable failures, well above what could be considered acceptable. Moreover, the Applicant took issue with OEB staff's suggestion that the issue of heat shrink splices has been mitigated, and in the worst performing areas of the Enersource RZ the issues are unrelated to heat shrink splices.

AMPCO submitted that these projects should not be approved because, in the Enersource RZ, the health index for underground cable is improving over time and the long-term rate of underground cable failures is stable. Alectra Utilities argued that the perceived trend that AMPCO highlighted was not indicative of improved health of this asset class but rather of a change in the health index methodology by Kinectrics.

### Findings

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding. In the last rebasing application for Enersource for 2013 rates,[50] the OEB approved a Subdivision Rebuild Program, and this project is reasonably part of that program.

*14. Enersource RZ Glen Erin & Battleford Subdivision Rebuild $2.06 million*

The Glen Erin & Battleford Subdivision Rebuild project involves renewing and replacing early generation underground distribution cables and five padmount transformers in the project area to bring them in line with present day standards. Alectra Utilities stated that:

- Increasing failures on early generation underground cables (which are mostly unjacketed and/or direct buried) are leading to increasing outages and adversely impacting reliability.
- Since 2005, 17 underground cable failures have occurred in this area, affecting 32,572 customers for a total of 191,139 outage minutes.

[50] Enersource Hydro Mississauga Inc. "Decision and Order Rates," EB-2012-0033, December 13, 2012.

- The cables and transformers in the area are approximately 40 years old and are beyond the end of their useful life.
- The 2016 asset condition assessment flagged these cables as being in very poor condition and in need of immediate replacement.
- This project is the preferred solution as it provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the six cable replacement projects are included with the Glen Erin & Montevideo Subdivision Rebuild project and not repeated here.

### Findings

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding. In the last rebasing application for Enersource for 2013 rates,[51] the OEB approved a Subdivision Rebuild Program, and this project is reasonably part of that program.

*15. Enersource RZ Credit Woodlands & Wiltshire Subdivision Rebuild*
*$1.55 million*

The Credit Woodlands & Wiltshire Subdivision Rebuild project involves replacing cables that are beyond the end of their useful life and transformers (11 in total) showing signs of leaks or containing PCBs. Alectra Utilities stated that:

- The replacement of transformers is needed to address safety, environmental, reliability, financial and regulatory risks and the replacement of cables is needed to address reliability issues.
- The cables and transformers in the area are approximately 37 years old.

[51] Ibid.

- The 2016 asset condition assessment flagged these assets as being in very poor condition and requiring immediate replacement.
- This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.
- The new cables will be installed in PVC ducts, making future replacements easier and less costly.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the six cable replacement projects are included with the Glen Erin & Montevideo Subdivision Rebuild project and not repeated here.

### Findings

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding. In the last rebasing application for Enersource for 2013 rates,[52] the OEB approved a Subdivision Rebuild Program, and this project is reasonably part of that program.

### *16. Enersource RZ Tenth Line Main Feeder Subdivision Renewal $1.14 million*

The Tenth Line Main Feeder Subdivision Renewal project involves renewing and replacing the early generation underground feeder cables in the Tenth Line area. Alectra Utilities stated that:

- The 2016 asset condition assessment (ACA) found the main feeder cables in this area to be in very poor condition and in need of immediate replacement.
- Two particular sections of direct buried cables have each failed four times, impacting a total of 7,074 customers and 3,684 customers, respectively.
- Portions of this cable are located in rear lots, making repairs particularly difficult and resulting in significant disruptions to residents.

[52] Ibid.

- This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.
- The new cables will be installed in PVC ducts, making future replacements easier and less costly.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the six cable replacement projects are included with the Glen Erin & Montevideo Subdivision Rebuild project and not repeated here.

**Findings**

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

The OEB also notes that in the last rebasing application for Enersource for 2013 rates,[53] the OEB approved a Subdivision Rebuild Program. This subdivision renewal program for the 10$^{th}$ line would reasonably be part of such a program. ICM funding is not available for typical annual capital programs.

*17. Enersource RZ Folkway & Erin Mills Main Feeder Subdivision Rebuild $1.03 million*

The Folkway & Erin Mills Main Feeder Subdivision Rebuild project involves renewing and replacing early generation underground feeder cables in the Folkway and Erin Mills area. Alectra Utilities stated that:

- The 2016 asset condition assessment found the main feeder cables in this area to be in very poor condition and in need of immediate replacement.
- One particular section of direct buried cable has failed five times, impacting a total of 6,220 customers.

[53] Ibid.

- Portions of this cable are located in rear lots, making repairs particularly difficult and resulting in significant disruptions to residents.
- This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.
- The new cables will be installed in PVC ducts, making future replacements easier and less costly.

PWU supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, did not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the six cable replacement projects are included with the Glen Erin & Montevideo Subdivision Rebuild project and not repeated here.

### Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

The OEB also notes that in the last rebasing application for Enersource for 2013 rates[54], the OEB approved a Subdivision Rebuild Program. This subdivision renewal program at Folkway and Erin Mills would reasonably be part of such a program. ICM funding is not available for typical annual capital programs.

*18. Enersource RZ City Centre Drive Rebuild (Walmart Cables) $1.55 million*

The City Centre Drive Rebuild – Walmart Cables project involves replacing existing cables and civil infrastructure in this area to mitigate the risk of a significant and prolonged outage, as well as to eliminate the safety hazards to field crews that arise from the current design of civil chambers. Alectra Utilities stated that:

- There are two subgrade utility chambers in this area that were constructed in the 1970s.

[54] Ibid.

- Chamber configuration and condition present significant constraints in terms of physical access. When responding to cable outages in the area, workers have to operate in substandard and hazardous conditions resulting in prolonged complicated repairs and safety and operational risks.

- Based on the condition of the cables, failure is highly probable in the near future and this would result in a significant and prolonged outage to a large customer that is supplied by these cables.

PWU and BOMA supported approval for recovery of the full amount proposed for this project. SEC, VECC, CCC and AMPCO, as well as OEB staff, did not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the six cable replacement projects are included with the Glen Erin & Montevideo Subdivision Rebuild project and not repeated here.

BOMA expressed its support for this project as it is: (1) driven by safety and efficiency concerns, (2) the condition of the existing asset appears to pose a serious operational risk to utility personnel, and (3) the proposed investment is somewhat discrete and unique with multiple benefits including a safe workplace.

**Findings**

ICM funding is not available for typical annual capital programs. The OEB finds that this project is part of a typical annual capital program and therefore is not approved for ICM funding. The OEB also notes that in the last rebasing application for Enersource for 2013 rates,[55] the OEB approved both a Subdivision Rebuild Program and a budget for Underground Distribution Sustainment, and this project is reasonably part of that typical work.

*19. Enersource RZ Lake/John Area Overhead Rebuild $0.93 million*

The Lake/John Area Overhead Rebuild project involves renewing the overhead system in the area south of Lakeshore Road W. between John Rd and Mississauga Rd. The project would mitigate the risks of pole fires due to porcelain insulators, worker and public safety concerns due to missing ground wiring and poles in poor conditions, as well as potential environmental contamination due to transformer oil leaks.

[55] Ibid.

Alectra Utilities stated that this project involves replacement of 50 poles that are in poor condition (with average age exceeding 40 years), 22 poles with problematic types of porcelain insulators, and 2 transformers showing signs of leaks. The project also includes the installation of copper clad ground wires to deter theft of ground wires and of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed.

PWU supports approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for the project.

Parties opposing the Overhead Rebuild projects argued that they are not unique relative to other overhead rebuild projects, they involve normal capital expenditures and they are part of routine ongoing work programs. Furthermore, OEB staff argued that the prudence and need criteria have not been met because Alectra Utilities has not shown an urgent need driving these expenditures and why this work cannot be deferred or paced by replacing individual worst-condition structures in these areas under the ongoing base capital Overhead Distribution Renewal and Sustainment program. BOMA argued that these projects involve the replacement of more assets than is necessary and that the replacement of defective or poor condition assets can be handled through the corresponding annual base capital programs.

Alectra Utilities submitted that OEB staff's argument in relation to the prudence and need criteria is misplaced. Alectra Utilities argued that the business cases for these projects:

- Include maps and other information, including lists of the system deficiencies such as copper theft, leaking transformers, sub-standard overhead configuration and insufficient mitigation of animal contact, all of which demonstrates that these assets are in poor condition.
- The business cases show that these assets have failed resistograph testing (which indicates internal deterioration of poles from rotting and cavities that may not be visible from outside).
- The risks of deferring these projects includes system reliability risks, environmental risks, as well as public and employee safety risks.
- The business cases explain that the option of only replacing the hazardous, worst-condition assets is not preferred because, although it carried lower near

term costs, over the longer term that option would result in increased maintenance, inspection and longer term replacement costs.

In response to BOMA's contention that these projects involve the replacement of more assets than is necessary, Alectra Utilities referenced[56] the business case, which indicates that all poles that are assessed to be in good condition will be maintained if possible.

**Findings**

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

*20. Enersource RZ Church St. Area Overhead Rebuild $1.02 million*

The Church St. Area 1 Overhead Rebuild project involves renewing the overhead system in the area east of Queen St. along Church St. to mitigate the risks of pole fires due to porcelain insulators, worker and public safety concerns due to missing ground wiring and poles in poor conditions, as well as potential environmental contamination due to transformer oil leaks. Alectra Utilities stated that this project involves the replacement of 55 poles that are in poor condition (with an average age exceeding 40 years), nine poles with problematic types of porcelain insulators, and six transformers that show signs of leaks. The project will also involve installation of copper clad alternative ground wires to deter theft, and the installation of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed.

PWU supports approval for recovery of the full amount proposed for this project. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment. General submissions by the intervenors, OEB staff and Alectra Utilities on the two overhead rebuild projects are included with the Lake/John Overhead Rebuild project and not repeated here.

[56] Application Attachment 47, p.46.

## Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is therefore approved.

*21. Enersource RZ Transformer Replacement Project $8.45 million*

Alectra Utilities stated that this is a mandatory project that involves replacement of 2,244 transformers that have been identified as showing signs of oils leaks or containing PCB in a planned and paced manner until 2021. Alectra Utilities stated that:

- This project addresses safety, environmental, reliability, financial and regulatory risks (particularly to avoid disruptive and costly environmental clean-up and ensure regulatory compliance).
- The need to minimize safety, environmental, reliability, financial and regulatory risks has led to the replacement of 2,052 transformers identified through rigorous inspections from 2013 to 2016.
- Transformer oil leaks at 103 sites led to $5.6MM in incurred costs for environmental remediation and $19.4MM in capital expenditures for transformer replacements from 2013 to 2016, which were not included in rates.
- Enersouce, and now Alectra Utilities, relied on the asset condition health index results from the 2016 asset condition assessment report by Kinectrics, based on 2015 data, through which 1629 transformers were identified to be in poor or very poor condition.
- Further inspections in 2016 resulted in a total of 2,244 in-service transformers identified as needing replacement.
- Replacements have been performed during planned underground or overhead system renewal projects in order to minimize the number of site visits and outages required.
- Leaking transformers replaced as part of system rebuild projects are not included in the backlog of leaking transformers to be replaced as part of this multi-year project.

PWU supported approval of the amount proposed, while SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, are opposed.

OEB staff argued that the prudence and need criteria have not been met because Alectra Utilities has not prioritized replacements based on the manner in which it has categorized the leaking transformers (i.e. all amounts of observed leakage have the same high priority).

A related argument from AMPCO and SEC is that all of the major and moderately leaking units appear to have already been replaced, so the replacements in the test year are only of units with minor leaking. SEC further argues that the replacements do not result in reliability or customer service benefits.

Finally, OEB staff commented that Alectra Utilities' new transformer asset condition assessment methodology, and its move away from the run-to-fail operational approach for overhead and pad-mounted distribution transformers, have the effect of driving this $8.45 million ICM expenditure in 2018, similar spending is expected for this item in each of the forecast years from 2019 to 2022, and that this is in contrast to the preference explicitly expressed by customers for control of rates.

Alectra Utilities submitted that projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary. Although OEB staff commented that flat expenditure trends are typical of multi-year programs rather than discrete projects, for this project the replacement of transformers is to address a backlog arising over a number of years and will therefore take a number of years to complete. The flat expenditure trend is a consequence of Alectra Utilities having appropriately paced the work on this project towards a decline and end in 2021.

Alectra Utilities submitted that it continues to run its distribution transformers on a run-to-failure basis. However, new information, obtained as a result of continuous improvements in inspection practices led to identifying that a number of its transformers are leaking. To ensure compliance with applicable environmental legislation and regulations, and to minimize the risk of environmental liability, Alectra Utilities stated that it must take action to address leaking transformers, and the only available solution is replacement. Transformers with minor leaks are still leaking, and the risk associated with this could give rise to increased costs in the future.

Alectra Utilities noted that there are approximately 1750 transformers remaining in-service that were identified as having minor leaking at some point between 2012 and 2016. Alectra Utilities submitted that minor oil leaks typically deteriorate into moderate or major leaks over time and when oil leaks, it compromises the transformer insulation and leads to premature failure.

Alectra Utilities noted that a number of the transformers contain PCBs, and that a spill may lead to compliance issues, and real and significant costs. Alectra Utilities submitted that the pacing for the project recognizes and seeks to minimize these risks and is therefore appropriate.

**Findings**

The OEB approves ICM funding of $8.45 million, effective May 1, 2018.

As part of Enersource's last rebasing application for 2013 rates[57] the OEB approved a capital expenditure of $1.004 million for a transformer replacement program. This was a typical annual capital program that any utility would be expected to have. From 2013 to 2016, Enersource undertook extensive inspections of its transformers. The asset health index using 2015 data identified a significant number of transformers in poor or very poor condition. Numerous oil leaks from transformers have also been found.

The OEB finds that it was prudent for Enersource to materially increase its spending on transformer replacements as a result of the new assessment of asset condition. The OEB is also concerned about potential environmental impacts of leaking transformers and agree that additional funding for transformer replacements is warranted.

The OEB finds that there is such a material change to the program that it is neither "typical" nor "ongoing" in 2018 from the program approved by the OEB for 2013 rates. Therefore for 2018, the OEB has determined that while this is still a transformer replacement program, it is not a typical ongoing capital program. The OEB expects that this project will evolve to be a typical ongoing capital program and may not be eligible for any additional incremental funding in subsequent years.

[57] EB-2012-0033, op.cit.

*22. Enersource RZ York MS $3.27 million*

This project involves upgrading York MS to increase station capacity to meet the forecast increase in demand and improve the reliability associated with station equipment and configuration. The project includes installation of low voltage switchgear, high voltage switchgear, and a 20 MVA power transformer. Alectra Utilities stated that:

- This project is driven primarily by growth in demand in the Meadowvale Business Park Area supplied by York MS.
- The area is forecast to experience an increase in load of 20 MVA over the next five years due to planned business and employment growth and approximately 50 % of this (10 MVA) will need to be supplied by York MS.
- York MS has a normal operating capacity of 20 MVA and present demand of 14 MVA.
- A second driver for this project is the need to update equipment and the configuration at the station to bring these in line with current standards and improve reliability. Originally commissioned in 1998 as a temporary station, the existing equipment and configuration is outdated and sub-standard, and experiences reliability issues associated with the cable egress, protection and station configuration.

PWU supports approval of the amount proposed, while SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, are opposed.

OEB staff, while accepting that the project is discrete, argued that need and prudence have not been demonstrated. OEB staff submitted that Alectra Utilities has not shown that this project was more critical than other projects in the substation upgrade base capital program or the Webb MS upgrade project, which was deferred for two years.

Alectra Utilities submitted that the business case demonstrates the need and prudence for the project and explains the basis for the growth projections.

Alectra Utilities also noted that the York MS was originally built as a temporary station that has poor reliability and needs to be upgraded to meet current standards.

BOMA argued that this project does not rise to the level of having a significant impact on the operation of the utility because it would only affect reliability for only 100 residential consumers. Alectra Utilities submitted that the York MS serves the Meadowvale Business Park and not residential customers. Alectra Utilities replied that the business park has a combination of commercial and industrial customers who would be significantly impacted in the event of a failure at the York MS.

**Findings**

The OEB approves ICM funding of $2.3 million, effective May 1, 2018.

The OEB has reviewed the options provided by Alectra Utilities in its DSP. Funding was requested for option 1 of $3.27 million to install a new 20 MVA transformer, an electrical house with low voltage switchgear, high voltage switchgear and civils works. The DSP also provided details of option 2 for $2.3 million. The work for option 2 includes all of the work for option 1 except the new transformer. Option 2 ensures the required substation transformer protection configuration is in place. It does not provide additional capacity for the projected growth, but would permit the addition of a second transformer in the future.

The OEB accepts that this substation was constructed as a temporary station and needs to be upgraded to meet current standards. The OEB finds however that it is appropriate to see a consolidated plan for Alectra Utilities before any funding for increased in capacity at York MS is re-considered. The evidence on options was based on the Enersource RZ and it is not clear whether supply options taking into consideration all of Alectra Utilities' service area were available. A consolidated plan will also take into account updated load forecasts, which can show whether the forecast load is materializing.

## 4.6 ICM True-up

Alectra Utilities stated that it intended to carry out the ICM true-ups at its next rebasing in accordance with OEB policy and would report at the project level.[58]

BOMA submitted that actual versus forecast cost for each approved ICM investment should be reviewed at the end of each year of the deferred rebasing period starting in 2019 and any underspending be credited to ratepayers at the next following annual rate review. Calculations should be done on a project basis and any overspending could be examined in the same timeframe.

[58] Argument-in-Chief, p. 25.

CCC submitted that if ICM relief is granted, Alectra Utilities should be required to report at a project level with respect to the ICM true-up process.

Alectra Utilities did not respond to the intervenor comments on the ICM true-up process in its reply submission.

**Findings**

The Funding of Capital Report states that at the next cost of service application:[59]

> …the actual costs and the recoveries would be reviewed for any material discrepancies. If there are significant variances between the revenue requirement based on actuals and the revenues collected through the ACM rate riders, the Board may decide to true up any differences.[60]

The OEB accepts Alectra Utilities' commitment to include a project-level report in its next rebasing application. At that time, the OEB will determine if a true-up is warranted between the revenues collected from the ICM rate riders and the revenue requirement calculated for the actual capital spending for the ICM projects.

## 4.7 Retail Transmission Service Rates

Distributors charge retail transmission service rates (RTSRs) to their customers to recover the amounts they pay to a transmitter, a host distributor or both for transmission services. All transmitters charge Uniform Transmission Rates (UTRs) approved by the OEB to distributors connected to the transmission system. Host distributors charge host-RTSRs to distributors embedded within the host's distribution system.

All four of Alectra Utilities' rates zones are partially embedded within Hydro One Networks Inc.'s distribution system. Alectra Utilities is requesting approval to adjust the RTSRs charged to customers to reflect the rates it pays for transmission services.

Alectra Utilities agreed with the submission of OEB staff that the 2017 RTSRs should be updated as part of the draft rate order process to reflect new UTRs that have been approved. Subsequent to the close of record in this proceeding, the OEB issued a decision for the 2018 UTRs.[61] The UTRs and host-RTSRs currently charged to Alectra

[59] This would apply to any rebasing application, both cost of service and Custom IR.
[60] Funding of Capital Report, September 18, 2014, p. 13.
[61] EB-2017-0359, op.cit.

Utilities are included in Tables 3 and 4.

**Table 3: UTRs**[62]

| Current Applicable UTRs (2018) | per kWh |
|---|---|
| Network Service Rate | $3.61 |
| Connection Service Rates | |
| Line Connection Service Rate | $0.95 |
| Transformation Connection Service Rate | $2.34 |

**Table 4: Hydro One Networks Inc. Sub-Transmission Host-RTSRs**[63]

| Current Applicable Sub-Transmission RTSRs (2017) | per kWh |
|---|---|
| Network Service Rate | $3.19 |
| Connection Service Rates | |
| Line Connection Service Rate | $0.77 |
| Transformation Connection Service Rate | $1.75 |

### Findings

The RTSRs in the application were based on the host-RTSRs and the UTRs current at the time of the filing. The OEB finds that the proposed RTSRs for each rate zone are to be updated and filed as part of the draft rate order to reflect the new 2018 UTRs that have been approved.

The differences resulting from the approval of new 2018 host-RTSRs will be captured in Accounts 1584 and 1586 for future disposition.

[62] Ibid.
[63] Decision and Rate Order “Hydro One Networks Inc. Application for electricity distribution rates and other charges beginning January 1, 2017,” EB-2016-0081, December 21, 2016.

## 4.8 Deferral and Variance Accounts

### a) Disposition of Group 1 Deferral and Variance Accounts (“DVA”)

In each year of an IRM term, the OEB reviews a distributor’s Group 1 deferral and variance accounts in order to determine whether their total balance should be disposed.[64] OEB policy requires that Group 1 accounts be disposed if they exceed (as a debit or credit) a pre-set disposition threshold of $0.001 per kWh, unless a distributor justifies why balances should not be disposed.[65] If the balance does not exceed the threshold, a distributor may elect to request disposition. The approved settlement proposal for Horizon Utilities accepted the proposal to adopt the same approach for Group 1 accounts during Horizon Utilities’ Custom IR term.

Alectra Utilities included in its application a request for the disposition of Group 1 deferral and variance accounts (DVAs) over a one-year period including carrying charges projected to December 31, 2017, for the Horizon Utilities, Brampton, PowerStream and Enersource RZs. Alectra Utilities identified that the Group 1 balances, by RZ, exceed the disposition threshold of $0.001/kWh.

<u>Horizon Utilities RZ</u>

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Horizon Utilities RZ in the credit amount of $7,370,171. OEB staff indicated that it has no concerns with the Applicant’s request to dispose of its December 31, 2016 Group 1 DVA balances. Alectra Utilities asked that the OEB approve the proposed disposition of its Group 1 DVA balances as requested.

<u>Enersource RZ</u>

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Enersource RZ in the credit amount of $7,421,393. OEB staff indicated that Alectra Utilities identified a credit amount of $7,401,082 in its argument-in-chief

[64] Group 1 accounts track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

[65] Report of the OEB – “Electricity Distributors’ Deferral and Variance Account Review Initiative (EDDVAR).” EB-2008-0046, July 31, 2009.

compared to the disposition credit amount of $7,421,393 included in the continuity schedule in the IRM Model. OEB staff asked Alectra Utilities to explain the difference and confirm the correct balance. No other parties made submissions on the Group 1 DVA balances for the Enersource RZ.

Alectra Utilities responded that in its argument-in-chief, it had identified a credit balance of $7,401,082. This represented the Group 1 balance to be disposed via rate rider. The amount to be disposed of via customer specific bill adjustments is a credit of $20,311 (credits of $18,635 GA and $1,676 CBR). The total amount requested for disposition is a credit of $7,421,393. Alectra Utilities confirmed that it sought approval to dispose of a total Group 1 credit balance of $7,421,393.

Brampton RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Brampton RZ in the credit amount of $5,732,154. OEB staff indicated that it had no concerns with respect to Alectra Utilities' proposals related to Group 1 DVA balances for the Brampton RZ. No other parties made submissions on the Group 1 DVA balances for the Brampton RZ. Alectra Utilities requested that the OEB approve the proposed disposition of its Group 1 DVA balances for the Brampton RZ.

PowerStream RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the PowerStream RZ in the credit amount of $20,528,056. In Alectra Utilities' argument-in-chief, Alectra Utilities identified a credit amount of $20,550,622. This represents the Group 1 balance to be disposed via rate rider. The amount to be disposed of via customer specific bill adjustments is a debit of $22,566 for CBR. The total amount requested for disposition is a credit of $20,528,056.

OEB staff submitted that the balance for disposition should be a credit of $22,168,522. The difference is due to an error in the amounts recorded under the "principal adjustments" and "interest adjustments" in 2016.

OEB staff submitted that the RPP settlement true-up adjustments were recorded as debits on the DVA continuity schedule, and they should have been recorded as credit amounts since the true-up settlement amount was a payment from the IESO.

No other parties made submissions on the Group 1 DVA balances for the PowerStream RZ.

Alectra Utilities agreed with OEB staff's submission and stated it would update the IRM Model to record the RPP settlement true-up adjustment as credit amounts.

### Findings

The OEB approves the disposition of the credit balances as of December 31, 2016, with interested project to April 30, 2017, for Group 1 accounts.

The following Tables 5, 6, 7 and 8 identify the principal amounts, with interest projected to December 31, 2017. As part of the rate order process, Alectra Utilities is directed to update the balances to include interest projected to April 30, 2018 at the OEB's current prescribed rate, subject to any adjustment to the Brampton RZ amount discussed in section 4.8 c).

**Table 5 – Group 1 Accounts - Horizon RZ**

| **Group 1 Accounts** | | Principal as at December 31, 2016 ($) | Interest Projected to December 31, 2017 ($) | Total ($) |
|---|---|---|---|---|
| LV Variance Account | 1550 | 552,752 | 9,052 | 561,804 |
| Smart Metering Entity Charge Variance Account | 1551 | (23,673) | (377) | (24,050) |
| RSVA - Wholesale Market Service Charge | 1580 | (4,482,609) | (74,881) | (4,557,490) |
| Variance WMS – Sub-account CBR Class A | 1580 | (0) | (0) | (0) |
| Variance WMS – Sub-account CBR Class B | 1580 | (185,940) | (2,903) | (188,843) |
| RSVA - Retail Transmission Network Charge | 1584 | (532,829) | (4,765) | (537,595) |
| RSVA - Retail Transmission Connection Charge | 1586 | 941,983 | 17,806 | 959,790 |
| RSVA – Power | 1588 | 671,361 | 22,523 | 693,884 |
| RSVA - Global Adjustment | 1589 | (4,813,354) | (52,992) | (4,866,346) |
| Disposition and Recovery/Refund of Regulatory Balances (2016) | 1595 | 194,908 | 393,767 | 588,675 |
| **Total Group 1 Balance excluding LRAMVA** | | **($7,677,400)** | **$307,229** | **($7,370,171)** |

## Table 6 – Group 1 Accounts - Enersource RZ

| **Group 1 Accounts** | | Principal as at December 31, 2016 ($) | Interest Projected to December 31, 2017 ($) | Total ($) |
|---|---|---|---|---|
| LV Variance Account | 1550 | 2,290,282 | 41,320 | 2,331,602 |
| Smart Metering Entity Charge Variance Account | 1551 | (33,444) | (692) | (34,136) |
| RSVA - Wholesale Market Service Charge | 1580 | (6,868,015) | (131,614) | (6,999,629) |
| Variance WMS – Sub-account CBR Class A | 1580 | | | |
| Variance WMS – Sub-account CBR Class B | 1580 | (275,214) | (5,472) | (280,686) |
| RSVA - Retail Transmission Network Charge | 1584 | (568,201) | 3,720 | (564,481) |
| RSVA - Retail Transmission Connection Charge | 1586 | 333,842 | 12,666 | 346,508 |
| RSVA – Power | 1588 | (350,628) | (25,469) | (376,097) |
| RSVA - Global Adjustment | 1589 | (1,860,431) | 21,884 | (1,838,547) |
| Disposition and Recovery/Refund of Regulatory Balances (2014) | 1595 | (58,585) | 52,658 | (5,927) |
| **Total Group 1 Balance excluding LRAMVA** | | **($7,390,396)** | **($30,999)** | **(7,421,393)** |

## Table 7 – Group 1 Accounts - Brampton RZ

| **Group 1 Accounts** | | Principal as at December 31, 2016 ($) | Interest Projected to December 31, 2017 ($) | Total ($) |
|---|---|---|---|---|
| LV Variance Account | 1550 | 247,217 | 3,964 | 251,180 |
| Smart Metering Entity Charge Variance Account | 1551 | (59,949) | (897) | (60,846) |
| RSVA - Wholesale Market Service Charge | 1580 | (3,726,242) | (58,136) | (3,784,378) |
| Variance WMS – Sub-account CBR Class A | 1580 | | | |
| Variance WMS – Sub-account CBR Class B | 1580 | (97,872) | (2,695) | (100,566) |
| RSVA - Retail Transmission Network Charge | 1584 | (479,528) | (8,793) | (488,321) |
| RSVA - Retail Transmission Connection Charge | 1586 | 555,267 | 8,328 | 563,595 |
| RSVA - Power | 1588 | (217,342) | (13,136) | (230,478) |
| RSVA - Global Adjustment | 1589 | (1,611,142) | (6,922) | (1,618,064) |
| Disposition and Recovery/Refund of Regulatory Balances (2013) | 1595 | (924) | (15) | (939) |
| Disposition and Recovery/Refund of Regulatory Balances (2014) | 1595 | 263,919 | (103,620) | 160,298 |
| Disposition and Recovery/Refund of Regulatory Balances (2015) | 1595 | (424,904) | 1,267 | (423,637) |
| **Total Group 1 Balance excluding LRAMVA** | | **($5,551,499)** | **($180,655)** | **(5,732,154)** |

### Table 8 – Group 1 Accounts - PowerStream RZ

| Group 1 Accounts | | Principal as at December 31, 2016 ($) | Interest Projected to December 31, 2017 ($) | Total ($) |
|---|---|---|---|---|
| LV Variance Account | 1550 | 4,477,534 | 88,685 | 4,566,219 |
| Smart Metering Entity Charge Variance Account | 1551 | (252,810) | (4,962) | (257,773) |
| RSVA - Wholesale Market Service Charge | 1580 | (25,885,605) | (591,222) | (26,476,826) |
| Variance WMS – Sub-account CBR Class A | 1580 | 0 | 0 | 0 |
| Variance WMS – Sub-account CBR Class B | 1580 | 1,947,271 | 51,253 | 1,998,524 |
| RSVA - Retail Transmission Network Charge | 1584 | (6,495,670) | (125,334) | (6,621,004) |
| RSVA - Retail Transmission Connection Charge | 1586 | 2,623,509 | 55,678 | 2,679,187 |
| RSVA – Power | 1588 | 1,047,973 | 50,164 | 2,720,755 |
| RSVA - Global Adjustment | 1589 | 890,272 | 93,168 | 1,001,287 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | 2 | (21,764) | (21,762) |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | 7,318 | 233 | 7,551 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | 336 | 47 | 382 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | 12,466 | 153,410 | 165,877 |
| Disposition and Recovery/Refund of Regulatory Balances (2014) | 1595 | 0 | (290,474) | (290,474) |
| **Total Group 1 Balance excluding LRAMVA** | | **($21,627,405)** | **(541,117)** | **(22,168,522)** |

### b) Proposal to Change Previously Approved Rate Riders

Alectra Utilities proposed to update the current 2016 GA rate riders with new 2016 GA rate riders for the period January 1, 2018 to September 30, 2018 in the PowerStream RZ. As part of its approved 2016 rates, Alectra Utilities has GA rate riders for the PowerStream RZ that expire September 30, 2018, and that apply to all Class B non-RPP customers (2016 GA rate riders). Alectra Utilities submitted that the Class B interval customers were billed actual GA and should not have been allocated any of the GA variance. Alectra Utilities projected that these Class B interval customers paid $3,134,585 to December 31, 2017 and that this over recovery should be refunded to

Class B interval customers and recovered from Class B non-RPP non-interval customers.

Alectra Utilities designed new 2016 GA rate riders to apply to Class B non-RPP non-interval customers to recover the projected balance remaining at December 31, 2017 of $3,906,837, plus the over recovery from the Class B interval customers from the 2016 GA rate riders of $3,134,585, for a total of $7,041,422.

OEB staff submitted that although some intergenerational inequity may exist, it would not have an impact on the total amount that the utility would recover and that this error could be corrected as part of the residual balance disposition given that the purpose of Account 1595 is to true-up approved balances. OEB staff indicated that Alectra Utilities is not making corrections to previously approved balances.

Alectra Utilities submitted that the OEB should approve the proposal to update the 2016 GA rate riders in the PowerStream RZ to ensure that the previously approved GA balance for disposition is allocated to the correct class of customers. Alectra Utilities proposed to recalculate the adjusted balances proposed for recovery and disposition based on the implementation date in the OEB's Decision on this application.

### Findings

The OEB approves Alectra Utilities' proposal to correct the 2016 GA rate riders to apply only to Class B non-RPP non-interval customers on a prospective basis. The interval customers were billed on the actual GA and therefore did not contribute to the GA variance. This is not a correction to previously approved balances, it is a correction to the calculation of the rate riders based on the applicability to only certain Class B customers. If the OEB does not approve this proposal, residual amounts from the disposition will flow through to Account 1595 for future disposition from all customers, not just the customers for whom the account balance was accumulated. Alectra Utilities is directed to update the rate riders for the implementation date of May 1, 2018.

## c) Disposition of Capacity Based Response ("CBR") Rate Rider for Class B Customers to Five Decimal Places

Alectra Utilities requested disposition of the CBR rate riders for Class B customers to the fifth decimal place for the Horizon Utilities, Brampton, and Enersource RZs. Alectra Utilities proposed that this treatment aligns disposition of the CBR balances with the

CBR bill adjustments for new Class A and new Class B customers and prevents intergenerational inequity.

In response to an OEB staff interrogatory,[66] Alectra Utilities confirmed that the billing systems in the Horizon Utilities and Enersource RZs have the ability to bill to five decimal places, but the Brampton RZ's billing system is limited to four decimal places.

OEB staff indicated that it does not oppose the approval of rate riders for CBR Class B balances to five decimal places in order to minimize intergenerational inequity.

Alectra Utilities requested that the OEB approve the proposed disposition of its CBR Class B balances to five decimal places for the Horizon Utilities and Enersource RZs. Alectra Utilities stated that it will seek disposition of the CBR Class B balance for the Brampton RZ in a future application.

**Findings**

The OEB approves the disposition of the CBR Class B balances for Horizon Utilities and Enersource RZs using rate riders to five decimal places.

It is not clear from Alectra Utilities' statement in the reply submission whether it was withdrawing its request for disposition of the CBR Class B balance for the Brampton RZ. This account was included in the $5,732,154 of Group 1 balances for which Alectra Utilities is seeking disposition. If Alectra Utilities is withdrawing its request, Alectra Utilities may remove the CBR Class B credit balance from Table 7 as part of the draft rate order, for future disposition.

### d) Requests for New Accounts

Alectra Utilities has asked for approval of an accounting order to establish two new deferral accounts, one for each of the PowerStream RZ and Enersource RZs, to record the financial impacts resulting from the Metrolinx Crossing Remediation Project.

Alectra Utilities stated that the Metrolinx Regional Express Rail (RER) Electrification will entail the conversion of six of the eight GO rail corridors from diesel to electric propulsion in the Greater Toronto and Hamilton Area. Alectra Utilities has determined that (i) all of the overhead crossings along the Lakeshore and Kitchener GO rail

[66] G-Staff-4.

corridors for the Enersource RZ and (ii) all of the overhead crossings along the Barrie and Stouffville GO rail corridors for the PowerStream RZ are in conflict with the planned overhead catenary system for the GO electrification. For the Enersource RZ, a total of 28 crossings and seven parallel lines along the Lakeshore and Kitchener corridors have been identified as being in conflict. For the PowerStream RZ, a total of 69 distribution system assets along the Barrie and Stouffville corridors have been identified as being in conflict.

Alectra Utilities further stated that the best option is to convert the crossings from overhead to underground. Alectra Utilities noted that the timeline for the Metrolinx tender is scheduled for 2019 for each of the rate zones and actual construction of the overhead catenary system is expected to start in 2020. Metrolinx has informed Alectra Utilities that several crossings will need to be remediated between 2017-2020 in the Enersource RZ and between 2017-2019 in the PowerStream RZ. Based on the proposed schedule, Alectra Utilities anticipates 10 crossings for the Enersource RZ and 10 to 15 crossings for the PowerStream RZ may need to be remediated in 2018 in order to align with Metrolinx’s schedule for construction.

Alectra Utilities stated that as Metrolinx has not finalized the final design and identification of the specific number crossings to be remediated, it has not been possible to develop project costs. Alectra Utilities added that it continues to monitor the progress and timelines of the project schedule, as they are dependent on Metrolinx.

OEB staff opposed the request for two new deferral accounts relating to the Metrolinx Projects stating that the request was not consistent with the OEB’s ICM policy. CCC similarly argued that Alectra Utilities could apply for ICM treatment for these projects at a future date. BOMA stated that it opposed the deferral accounts request but indicated that once costs were incurred, Alectra Utilities could apply for a deferral account at that time.

VECC submitted that all of the transit related projects included in the ICM applications should be subject to deferral account treatment. In VECC’s view, this included both Metrolinx projects in the PowerStream RZ and Enersource RZ, the YRRT in the PowerStream RZ and the QEW widening in the Enersource RZ.

Alectra Utilities submitted that the Metrolinx projects are appropriate for deferral account treatment as they meet all of the OEB’s criteria and were unanticipated. Alectra Utilities submitted that the expenditures will be significantly in excess of the OEB-approved threshold and will be subject to a prudence review at the time of the clearance of the accounts.

Alectra Utilities referred to the OEB's approval of a variance account for Toronto Hydro[67] to track the difference between the amounts included in base distribution rates for third party initiated relocation and expansion capital spending and the amounts actually spent on such work as it occurs over Toronto Hydro's Custom IR term. Alectra Utilities noted that this Toronto Hydro account relates to non-discretionary requests from third parties to relocate parts of its distribution system and the cost and timing are outside of Toronto Hydro's control. Alectra Utilities stated that a draft accounting order is included in the application.[68]

Alectra Utilities further requested that the OEB consider addressing the GO Transit electrification project on a generic basis as it is an issue that will affect approximately one dozen OEB-regulated utilities across four regional municipalities, one county, five cities and five towns.

SEC and CCC suggested that the Metrolinx projects may be more appropriately dealt with through an ICM when details are more clearly defined. BOMA raised concerns that the deferral account approach would circumvent the ICM policy and that costs are not being appropriately shared. Alectra Utilities replied that if the only potential for relief for a distributor is to fund such work through base rates or through an ICM, then the revitalization/electrification of transportation systems will crowd out virtually all other necessary capital work due to the timing and sheer magnitude of the transportation work to be completed.

**Findings**

The OEB does not approve the new deferral accounts. The OEB has adopted the ICM for incremental funding for capital projects. When more details of these projects are available, including budgets and in-service date, Alectra Utilities can apply for an ICM if it meets the OEB's criteria. To adopt deferral accounts to address the funding of capital would make the ICM materiality threshold calculation meaningless because there would be two different funding mechanisms for incremental capital.

The OEB disagrees with Alectra Utilities that this is an analogous situation to the variance account approved for Toronto Hydro. Toronto Hydro's application was part of a Custom IR application in which cost forecasts are reviewed, not part of an IRM

[67] Decision and Order "Toronto Hydro-Electric System Limited Application for electricity distribution rates effective from May 1, 2015 and for each following year effective January 1 through to December 31, 2019," EB-2014-0116, December 29, 2015.
[68] Application, Attachment 40. Attachment 27 contains the draft PowerStream accounting order.

application. As stated in the Chapter 3 Filing Requirements: “the IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious.”

The OEB is also concerned about the cost sharing arrangements. Having the electricity distributor pay the majority of costs is not fair to electricity customers and is inconsistent with how cost sharing has been legislated for works on highways.[69] Alectra Utilities should continue its negotiations on cost sharing arrangements.

As to Alectra Utilities’ submission that the OEB open a generic deferral account for Metrolinx projects, and that these projects would crowd out other necessary capital work, there is no evidence on the magnitude of this work for other distributors and whether this will dominate other capital work. Even for Alectra Utilities there is only an approximate estimate at this point because Metrolinx has not defined the final project design and number of crossings yet.

### e) Lost Revenue Adjustment Mechanism (LRAMVA)

As part of the Ministry of Energy’s conservation-first policy, distributors have an OEB licence requirement to ensure CDM programs are available to their customers. These programs result in reduced total energy consumption. To address the impact of the reduced consumption, the OEB established a Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) to capture a distributor's revenue implications resulting from differences between actual load and the last OEB-approved load forecast. These differences are recorded by distributors at the rate class level.

A distributor may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of its IRM application, if the balance is deemed significant by the distributor. A request for the inclusion of lost revenues from demand response programs as part of the LRAMVA, must be addressed through a rebasing application.

Alectra Utilities has requested disposition of the balances in its LRAMVAs resulting from its CDM activities as of December 31, 2015 for each of the Horizon Utilities, PowerStream and Enersource RZs. The former Hydro One Brampton disposed of the

[69] *Public Service Works on Highways Act.*

balances in its LRAMVA as of December 31, 2015, as part of its 2017 IRM application[70] so LRAMVA disposition is not sought for the Brampton RZ in this application.

For each of these three rate zones, Alectra Utilities has stated it determined the LRAMVA balance in accordance with the OEB's 2012 CDM Guidelines and 2015 CDM Guidelines. Alectra Utilities completed the OEB's 2018 LRAMVA work form for each of the three rate zones. In accordance with the OEB's 2016 Updated Policy on the calculation of peak demand savings, Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Horizon Utilities, PowerStream and Enersource RZs in its lost revenue calculation. The detailed calculations were updated based on Alectra Utilities' response to an undertaking.[71]

Horizon Utilities RZ

Horizon Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR application.[72] In that proceeding, the OEB approved Horizon Utilities' request to recover lost revenues from CDM activities in 2011 and 2012. Horizon Utilities' actual savings from CDM activities for 2013 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount requested for disposition in this application is a debit of $1,339,931 including interest of $51,220 projected to December 31, 2017.

PowerStream RZ

PowerStream's most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR application.[73] In that proceeding, the OEB approved PowerStream's request to recover lost revenues from CDM activities in 2013. Actual savings from CDM activities for 2014 and 2015 in the PowerStream RZ were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount requested for disposition in this application is a debit of $1,977,404 including interest of $62,106 projected to December 31, 2017.

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[70] EB 2016-0080.
[71] JT.Staff-8.
[72] EB-2014-0002.
[73] EB-2015-0003.

Enersource RZ

Enersource's most recent application for the recovery of lost revenues due to CDM activities was filed in a stand-alone LRAM application.[74] In that proceeding, the OEB approved Enersource's request to recover lost revenues from persisting historical impacts of pre-2011 CDM programs in 2011 and 2012. Enersource's actual savings from CDM activities for 2011 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount requested for disposition in this application is a debit of $2,077,134 including interest of $102,149 projected to December 31, 2017.

### Findings

The OEB finds that Alectra Utilities' LRAMVA balances for the Horizon Utilities, PowerStream and Enersource RZs have been calculated in accordance with the CDM-related guidelines and updated LRAMVA policy. The OEB approves the disposition of Alectra Utilities' LRAMVA debit balances, with interest projected to April 30, 2018. Balances with interest projected to December 31, 2017 are set out in Table 9 below.

**Table 9 LRAMVA Balance for Disposition**

| Rate Zone | Account Number | Principal Balance | Interest to December 31, 2017 | Total Claim ($) |
|---|---|---|---|---|
| Horizon | 1568 | $1,288,711 | $51,220 | $1,339,931 |
| PowerStream | 1568 | $1,915,298 | $62,106 | $1,977,404 |
| Enersource | 1568 | $1,974,985 | $102,149 | $2,077,134 |

Alectra Utilities is directed to update the interest calculation up to April 30, 2018, and file revised rate riders for recovery of the LRAMVA balances as part of the rate order process.

[74] EB-2013-0024.

## 4.9 Residential Rate Design

All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB's residential rate design policy stipulates that distributors will transition residential customers to a fully fixed monthly distribution service charge over a four-year period, beginning in 2016.[75] The OEB requires distributors filing applications for 2018 rates to continue with this transition by once again adjusting their distribution rates to increase the fixed monthly service charge and decrease the variable charge consistent with the policy.

The OEB expects an applicant to apply two tests to evaluate whether mitigation of bill impacts for customers is required during the transition period. Mitigation usually takes the form of a lengthening of the transition period. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10th percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

Alectra Utilities confirmed in its reply submission that the monthly service charge was not increasing by more than $4, nor would the customer at the 10th consumption percentile of electricity consumption have a bill impact of 10% or more for the Horizon Utilities, Brampton, Enersource and PowerStream RZs.

OEB staff submitted that the method used to calculate the fixed rate was in accordance with OEB policy and no mitigation is required. Intervenors did not object to Alectra Utilities' proposals on this matter.

### Findings

The OEB finds that the proposed 2018 increases to the monthly fixed charges for the Brampton, Enersource and PowerStream RZs were calculated in accordance with the OEB's residential rate design policy. The OEB approves the proposed increases in the fixed distribution rate and corresponding decreases in the variable distribution rate for the residential rate class in each rate zone. The effect on the monthly fixed charge, and

[75] OEB Policy – "A New Distribution Rate Design for Residential Electricity Customers." EB-2012-0410, April 2, 2015.

total bill impact for low consumption residential consumers shows that no mitigation is required.

For the Horizon Utilities RZ there will be updates to proposed rates resulting from this Decision. The OEB is satisfied that with these updates the two tests for rate mitigation will still show that rate mitigation is not required. Alectra Utilities is directed to update the Horizon RZ rates resulting from this Decision using its proposed methodology for transitioning to the fully fixed charge for residential customers.

## 4.10 Capitalization Policy

Alectra Utilities was required by applicable accounting standards[76] to implement a new capitalization policy in 2017 (following the consolidation) to conform capitalization policies for the Alectra Utilities predecessor rate zones to that of the identified acquirer, the former PowerStream Inc., as part of its merger transaction.

In the Decision on Issues List and Interim Rates and Procedural Order No. 3, the OEB rendered its decision on the final issues list for this proceeding. The OEB determined that it would add a new issue relating to the change in capitalization policy.

The OEB established three new deferral accounts "to track the change in capitalization" for the Horizon Utilities, Enersource and Brampton RZs. The OEB also asked Alectra Utilities for confirmation that the capitalization change had no impact on Horizon Utilities' 2016 earnings; and invited parties to provide any comments "on the recording details" for the new accounts by December 7, 2017. The OEB concluded by expressly noting that "[t]he nature of any disposition of these accounts is not being determined at this time" and that submissions in this respect would be heard as part of final argument".

By letter dated December 7, 2017, Alectra Utilities confirmed that the change in capitalization policy had no impact on Horizon Utilities' 2016 earnings and no impact on the proper calculation of the Horizon Utilities RZ ESM.

Alectra Utilities submitted that the OEB should order the closure of the capitalization related deferral accounts and the reversal of any amounts recorded in those accounts. Alectra Utilities explained that it was taking this position as the capitalization policy change is a non-cash event that had no impact, and will have no impact going forward,

[76] The Canadian Accounting Standards Board (AcSB) has adopted International Financial Reporting Standards ("IFRS") for Canada.

on the underlying cost of utility business. Further, Alectra Utilities argued that OEB policy does not support any claim for rate adjustment at this time.

Alectra Utilities claimed that both the OEB's filing requirements and MAADs policy are clear that, where a rebasing deferral period has been approved by the OEB for a consolidation transaction, accounting changes (including changes in capitalization policy) that are required within the consolidated entity pursuant to applicable accounting standards during the rebasing deferral period, are not to be reflected in rates until such time as the consolidated entity rebases.

Alectra Utilities argued that the capitalization policy change is a function of the integration, and that the savings or costs arising from integration are to the account of the shareholder as specified in the MAADs Handbook[77] and, more recently, in the MAADs Decision.[78]

SEC argued that Alectra Utilities' proposal would collect a total of $53.2 million[79] from customers twice, first as part of the OM&A budget and second as part of the expenses now to be capitalized and included in rate base at the end of the 10-year deferred rebasing period. SEC also noted that the impacts of the capitalization policy were not disclosed to the OEB when approval was sought for the merger during the MAADs proceeding.[80]

SEC submitted that the amount recorded for 2017 should be processed as rate riders in 2018, with amounts continuing to be recorded and cleared annually to the end of the deferred rebasing period. SEC stated that another option was to the hold amounts in the deferral accounts until the rebasing, but there does not appear to be any principled reason to leave balances accumulating for 10 years.

Alectra Utilities submitted that parties who argued that the impact of the capitalization change would be recovered twice in rates assume that Alectra Utilities would seek, and be permitted by the OEB to recover, amounts once through OM&A and again through rate base.

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[77] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, pp. 8-9.
[78] Decision and Order "Enersource Hydro Mississauga Inc. Horizon Utilities Corporation & PowerStream Inc. Application for approval to amalgamate to form LDC Co and for LDC Co to purchase and amalgamate with Hydro One Brampton Networks Inc." EB-2016-0025/EB-2016-0360, December 8, 2016, p.16.
[79] SEC also provided after-tax impacts to Alectra Utilities and grossed up tax impacts to customers.
[80] EB-2016-0025/EB-2016-0360.

BOMA submitted that the capitalization policy change qualifies as a Z-factor for each of the Enersource, Horizon Utilities, and Brampton RZs, and adjustments should be made for 2019 rates. Alectra Utilities disagreed on the basis that the capitalization change is not an event that is external to the utility and therefore does not meet the z-factor criteria. Alectra Utilities argued that it was required to adopt a uniform capitalization policy on merger across all of its rate zones, which was an event entirely within the control of the merging parties.

Both OEB staff and AMPCO argued that the balances in the capitalization related deferral accounts should be cleared in favour of ratepayers annually (AMPCO) or every two years (OEB staff). Alectra Utilities submitted that this would be inconsistent with OEB policy that income impacts arising from a merger should accrue to shareholders, and would convert a non-cash accounting impact to the utility into a cash outcome for customers.

Alectra Utilities argued that the three deferral accounts opened to record the impact of the change in capitalization policy accounts should be closed without clearing the balances.

### Findings

The OEB finds that the change in capitalization policy is not a "benefit" accruing to shareholders as claimed by Alectra Utilities.

Neither the MAADs policy nor the MAADs Handbook addressed a change in capitalization policy resulting from a merger. In contrast, the OEB did require utilities to provide justification when opting to use different accounting standards for financial reporting (i.e. changing from International Financial Reporting Standards (IFRS) to USGAAP) following the closing of the proposed merger transaction. Alectra Utilities did not pursue this option and did not seek any such approval in its MAADs application.

In its MAADs application, Alectra Utilities did not disclose to the OEB that applicable accounting standards mandated a capitalization change for three of the rate zones. The OEB issued its MAADs decision based on the evidence before it. The MAADs decision was silent as the issue was not raised. This Decision is the OEB’s first opportunity to consider and opine on the appropriate regulatory treatment for a mandated accounting change resulting from the merger.

Alectra Utilities stated that the change in the capitalization policy was a "non-cash event that had no impact, and will have no impact going forward, on the underlying cost of utility business."[81] The OEB agrees. The change in capitalization policy does, however, change the type of costs (OM&A or capital) and the timing of cost recognition, which is relevant when setting electricity rates.

The OEB's MAADs policy was established to incent consolidations by permitting utilities to keep efficiency gains to offset the costs of the transaction. The change in capitalization policy has no impact on underlying total costs and therefore on efficiency. It simply moves some costs from OM&A to capital (for Enersource RZ and Horizon Utilities RZ) and vice versa (for Brampton RZ). The OEB finds that it is neither an efficiency gain nor a "benefit" of the merger that should accrue to shareholders, to be used to offset the costs of the merger transaction, as claimed by Alectra Utilities. Having found that mandatory accounting changes are distinct from efficiency gains that accrue to shareholders, the next question is whether there should be an adjustment to 2018 rates as a result of this mandated accounting change. The OEB is not approving an adjustment to 2018 rates for this change. The OEB will consider a change to the 2019 rates.

To consider rate changes during the deferred rebasing period, the OEB created three deferral accounts to track the costs. The OEB did not establish a deferral account for the PowerStream RZ as no capitalization policy change was required.

For the Horizon Utilities RZ there is a Custom IR framework pursuant to the approved settlement proposal that stated:

> Horizon Utilities also agrees that it will not make any material changes in accounting practices that have the effect of either reducing or increasing utility earnings unless otherwise directed to do so by the OEB, or by an accounting standards body and/ or provincial or federal government and approved by the OEB. Any such changes shall be noted at the time of any proposed ESM disposition.[82]

The Custom IR framework described in the Rate Handbook stated that the OEB "expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale".[83] The Horizon Utilities Custom IR framework, as outlined in the approved settlement proposal, pre-

[81] "Applicant's Reply Submission," op.cit., p. 81.
[82] Horizon Utilities Corporation "Settlement Proposal," EB-2014-0002, September 22, 2014, p. 22.
[83] "Handbook for Utility Rate Applications," op.cit., pp. 26-27.

dated the Rate Handbook and had a number of prescribed annual adjustments and openers, including an ESM. The approved settlement proposal did not specify how a material change in accounting practice would be treated, just that it would be noted. The approved settlement proposal was a "package deal" which the OEB approved. The approved settlement proposal did not include mandated accounting changes as a reopener, and therefore the OEB will not approve one now. For the remainder of the Custom IR term, the effect on earnings resulting from the change in the capitalization policy will be dealt with through the ESM. Once the Custom IR term ends, the Horizon Utilities RZ will move to Price Cap IR per the MAADs policy, and it will be treated consistently with the Brampton and Enersource RZs. Alectra Utilities shall retain the deferral account opened for Horizon Utilities RZ,[84] however, the first entries to the account shall begin January 1, 2020.

The Brampton and Enersource RZs are on Price Cap IR. For these rates zones, the OEB finds it appropriate to retain the balances recorded in the deferral accounts approved in the Decision and Partial Accounting Order effective February 1, 2017. The OEB acknowledges Alectra Utilities' reply submission that future rate recovery has yet to be determined as subsequent applications and proposals have yet to be filed. The OEB finds that this future uncertainty creates a regulatory risk, and that this risk is appropriately addressed through deferral accounts to enable ratemaking options.

The OEB disagrees that mandatory accounting changes are only made in rebasing applications. When Canada transitioned to IFRS, most distributors had mandated changes to depreciation expense and capitalization policies. The OEB required that the impact of these mandatory IFRS-related changes be recorded in specific accounts for future disposition.[85] The OEB subsequently approved disposition of these accounts in both cost of service and IRM decisions.[86] The OEB finds it appropriate to enable disposition of the Impact of Post-merger Capitalization Policy Changes accounts for the Enersource and Brampton RZs during the Price Cap IR term, consistent with regulatory precedent. The OEB finds that both the transition to IFRS and the capitalization policy change from the merger were due to mandated accounting standards established by

[84] Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes HRZ.
[85] Accounts 1575 and 1576 were used depending on when changes were made, either at the time of a rebasing application or during an IRM term.
[86] Examples of IRM applications in which balances accumulated for the transition to IFRS have been disposed include Newmarket-Tay Power Distribution Ltd. EB-2016-0275, and Whitby Hydro Electric Corporation EB-2016-0114.

the Canadian Accounting Standards Board (AcSB), and the OEB should apply consistent regulatory treatment.

While amounts for Alectra Utilities could be held in the accounts approved by the OEB until the next rebasing, and used as an offset to rate base, the deferred rebasing period is 10 years. This is an unreasonably long time to wait for disposition of the accounts. Given the complexities of determining amounts that should be credited to customers, such as tax treatment, the OEB finds that Alectra Utilities shall file a proposal for disposition of the deferral accounts in its application for 2019 rates for the Brampton and Enersource RZs.

## 4.11 Monthly Billing

On April 15, 2015, the OEB amended the Distribution System Code and announced that all distribution utilities must migrate their residential and GS<50kW customers to monthly billing, no later than January 1, 2016. Alectra Utilities did not seek any relief related to its transition to monthly billing in the current application.

OEB staff, along with VECC, BOMA and PWU did not make any submissions on monthly billing.

SEC submitted that the OEB should order creation of deferral accounts to track the cumulative impact of monthly billing for each of the affected rate zones. Starting in 2019, whenever the cumulative net impact (savings less costs) is a credit, the accounts should be cleared by way of a refund to customers. CCC and AMPCO supported the submission of SEC.

Alectra Utilities argued that the origin of the benefit is based on the assumption by SEC that the distributor, having migrated its customers to monthly billing, must immediately change its working capital allowance percentage to the OEB default of 7.5%.

Alectra Utilities stated that its predecessor Hydro One Brampton had already implemented monthly billing. Its predecessor, PowerStream, implemented monthly billing as of January 1, 2017; and Alectra Utilities implemented monthly billing in the Horizon Utilities RZ as of June 30, 2017. Alectra Utilities noted that this proceeding is for electricity distribution rates effective January 1, 2018.

Alectra Utilities also submitted that the approved settlement proposal for Horizon Utilities was clear on the areas that would be subject to annual updates and reopeners.

Alectra Utilities noted that there was no reopener, nor an annual update for the working capital allowance percentage.

**Findings**

The OEB will not establish new deferral accounts to track the impact of monthly billing for each rate zones as proposed by SEC.

The OEB required all distributors to bill customers on a monthly basis. This may have included costs to alter billing systems, additional billing and payment processing costs, and for some, reduced costs for working capital by collecting from customers earlier. The extent to which additional costs were offset by improvement in working capital is unknown, and is not in evidence in this proceeding.

The OEB acknowledges that all rate zones implemented monthly billing prior to 2018. It would be inappropriate to establish deferral accounts effective January 1, 2018, after the implementation dates, to track only prospective impacts of monthly billing. In addition, there was no evidence in this proceeding that the impacts could be material for any rate zone, and materiality is a requirement for establishing a new deferral account.

## 4.12 Effective Date

Alectra Utilities requested that final rates be made effective January 1, 2018. The OEB declared Alectra Utilities’ current rates interim effective January 1, 2018, pending this Decision.

SEC, supported by CCC and AMPCO, opposed Alectra Utilities’ request for final rates effective January 1 arguing that rates should be effective on the first day of the month following the OEB’s rate order. SEC submitted that this approach is the OEB’s normal practice. The other parties made no submission on this matter.

Alectra Utilities indicated that for applications seeking January 1 2018 rates, the OEB’s filing deadline was August 28, 2017 for Custom IR annual updates and August 14, 2017 for IRM applications. Alectra Utilities argued that it filed its application on July 7, 2017, in advance of these dates.

Alectra Utilities also argued that there was no oral hearing for this proceeding and that the OEB target processing time for rate applications is 185 days for a standard application when there is no oral hearing.[87]

Finally, Alectra Utilities disagreed that there is a “normal practice” that rates should be effective only from the month following the OEB’s rate order, and noted a recent case in which the effective date was earlier.

### Findings

The OEB approves an effective date to base rates of January 1, 2018 for the Horizon Utilities’ RZ related to its Custom IR update. The OEB also approves an effective date of January 1, 2018 for the Brampton, Enersource and PowerStream RZs with respect to the Price Cap IR increases. The OEB will approve the recovery of the foregone revenue from the approved effective date to the implementation date for these rates. Rate riders for all deferral and variance accounts approved for disposition will be in effect for 12 months, effective May 1, 2018. The OEB directs Alectra Utilities to file the rate riders for the foregone revenue and deferral and variance account dispositions, and provide the calculations, in the draft rate order.

The OEB finds that a January 1, 2018 effective date is appropriate for the Custom IR and Price Cap IR base rate changes as Alectra Utilities filed its application in advance of the OEB’s associated recommended filing deadlines.

Regarding the ICMs approved in this Decision, the effective date will be May 1, 2018. The OEB finds that the ICM-related aspects of the application required additional time to review and test the evidence, and resulted in the scheduling of a technical conference that concluded on December 1, 2017. The record of the proceeding closed on January 30, 2018 and the OEB issued its Decision approximately two months after. The OEB finds it reasonable for the effective date of the ICM rate riders to follow the issuance of the OEB’s Decision and final rate order, especially as the half-year rule does not apply to the ICM rate riders and it is unlikely that Alectra Utilities will have completed all of the ICM projects for 2018 when the ICM rate riders are implemented.[88] ICM rate riders also do not have pre-established end dates and continue until the next rebasing application.

[87] The OEB notes that this target date is to the decision and, for typical rate applications such as this one, there is a rate order process before a final Tariff of Rates and Charges is approved.
[88] For determining a return on rate base, the OEB uses an average of opening and closing asset balances, which results in a mid-year rate base.

# 5 IMPLEMENTATION

The OEB directs Alectra Utilities to revise the proposed rates to reflect the findings in this Decision and to file a draft rate order for rates to be implemented May 1, 2018 based on the effective dates determined in this Decision.

The OEB expects Alectra Utilities to file detailed supporting material showing the impact of this Decision on the rates and rate riders, including bill impacts.

Alectra Utilities' draft rate order should include a revised Tariff of Rates and Charges reflecting this Decision, and including updates to the RRRP charge, DVA rate riders for interest projected to April 30, 2018, ICM rate riders, etc.). In addition, the Smart Metering Entity Charge was set at $0.57 by the OEB, effective January 1, 2018 to December 31, 2022.[89] The Tariff of Rates and Charges should be adjusted to incorporate this rate.

AMPCO, BOMA, CCC, SEC, and VECC are eligible for cost awards in this proceeding. The OEB will make provision for these intervenors to file their cost claims in its final rate order.

[89] Decision and Order, "Independent Electricity System Operator/Smart Metering Entity Application for approval of smart metering charge for the 2018-2022 period," EB-2017-0290, March 1, 2018.

# 6 ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. Alectra Utilities shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision, no later than April 16, 2018. Alectra Utilities shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Alectra Utilities within **7 days** of the date of filing of the draft rate order. The OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.

3. Alectra Utilities shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order within **5 days** of the date of receipt of the comments.

All filings to the OEB must quote the file number, EB-2017-0024, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies.

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

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Martin Davies at martin.davies@oeb.ca and OEB Counsel, Ljuba Djurdjevic at ljuba.djurdjevic@oeb.ca.

## ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON  M4P 1E4
Attention:  Board Secretary

E-mail: Boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

**DATED** at Toronto April 5, 2018 (Revised: April 6, 2018)

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli
Board Secretary

# EP-3

# ATTACH 6

# The Decision and Rate Order of the OEB in Alectra Utilities' 2018 EDR Application (EB-2017-0024) Issued May 3, 2018

Ontario

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

# DECISION AND RATE ORDER

## EB-2017-0024

## ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates and other charges beginning January 1, 2018**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**May 3, 2018**

## INTRODUCTION

Alectra Utilities Corporation (Alectra Utilities) filed an application with the Ontario Energy Board (OEB) on July 7, 2017 under section 78 of the *Ontario Energy Board Act*, *1998* (OEB Act), and under the OEB's *Filing Requirements for Incentive Rate-setting Applications* seeking approval for changes to its electricity distribution rates to be effective January 1, 2018. Under section 78 of the OEB Act, a distributor must obtain an order from the OEB to change the rates it charges its customers.

On April 5, 2018 (revised: April 6, 2018), the OEB issued its Decision and Order (Decision) on the application. Among other matters, the Decision established dates for Alectra Utilities to file a draft rate order (DRO) reflecting the OEB's findings in the Decision, and for OEB staff and intervenors to file comments on the DRO and Alectra Utilities to file responses to any such comments.

On April 16, 2018, Alectra Utilities filed its DRO. On April 23, 2018, OEB staff filed its comments on the DRO and on April 27, 2018, Alectra Utilities filed its reply submission and an updated DRO.

The OEB has reviewed the materials filed by Alectra Utilities in support of the proposed Tariff of Rates and Charges. The OEB is satisfied that these documents accurately reflect the OEB's Decision. The OEB finds that the concerns raised by OEB staff in its submission have been adequately addressed. The OEB has made one change to the draft Tariff of Rates and Charges to include the May 1, 2018 effective date with the rate riders for the incremental capital modules, disposition of deferral and variance accounts, lost revenue adjustment mechanism and foregone revenue. The Tariff of Rates and Charges in Appendix A is approved.

As a result of this Rate Order, it is estimated that for a typical residential customer with an average monthly consumption of 750 kWh, the total bill by rate zone will change as follows:

| Rate Zone | Bill Increase/Decrease per month | Percentage Increase/Decrease |
|---|---|---|
| Horizon Utilities | $0.84 | 0.80% |
| Brampton | $2.83 | 2.85% |
| PowerStream | -$2.27 | -2.14% |
| Enersource | $1.46 | 1.43% |

**The ONTARIO ENERGY BOARD ORDERS THAT:**

1. The Tariff of Rates and Charges set out in Appendix A of this Decision and Rate Order is approved effective January 1, 2018 for electricity consumed or estimated to have been consumed on or after January 1, 2018, except for rate riders for the incremental capital modules (ICMs), disposition of deferral and variance accounts (DVAs), lost revenue adjustment mechanism (LRAMVA) and foregone revenue. The rate riders for the ICMs, DVAs, LRAMVA and foregone revenue are effective May 1, 2018. All rates are to be implemented on May 1, 2018. Alectra Utilities shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

2. Intervenors shall file with the OEB and forward to Alectra Utilities their respective cost claims by May 10, 2018.

3. Alectra Utilities shall file with the OEB and forward to intervenors any objections to the claimed costs to the claimed costs by May 17, 2018.

4. Intervenors shall file with the OEB and forward to Alectra Utilities any responses to any objections for cost claims by May 24, 2018.

5. Alectra Utilities shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, EB-2017-0024, be made in searchable/ unrestricted PDF format electronically through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

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

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Martin Davies at martin.davies@oeb.ca and OEB Counsel, Ljuba Djurdjevic at ljuba.djurdjevic@oeb.ca.

**ADDRESS**

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON  M4P 1E4
Attention: Board Secretary

E-mail: Boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

**DATED** at Toronto, May 03, 2018

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli
Board Secretary

**APPENDIX A**

**DECISION AND RATE ORDER**

**ALECTRA UTILITIES CORPORATION**

**EB-2017-0024**

**MAY 3, 2018**

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 23.67 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (0.16) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0040 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0006) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0074 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0068 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 41.22 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (0.25) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | (0.23) |
| Distribution Volumetric Rate | $/kWh | 0.0106 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1 ,2018 until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | 0.0005 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0065 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0061 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 379.54 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (2.27) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.70 |
| Distribution Volumetric Rate | $/kW | 2.5565 |
| Low Voltage Service Rate | $/kW | 0.02169 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1080 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3086) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.01730) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0575 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0153) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.5869 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.4536 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 23,720.06 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (142.57) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | (55.64) |
| Distribution Volumetric Rate | $/kW | 1.3995 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1418 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4569) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.02611) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.2338 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0084) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9551 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.8195 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5,610.14 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (33.55) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 12.64 |
| Distribution Volumetric Rate | $/kW | 0.3310 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1635 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3761) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0020) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0049 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9551 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.8195 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

| | | |
|---|---|---|
| GS>50 Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 2.5565 |
| Large Use Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 1.3995 |
| Large Use with Dedicated Assets Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 0.3310 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 8.43 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (0.05) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | (0.04) |
| Distribution Volumetric Rate | $/kWh | 0.0131 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0001) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0066 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0062 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 5.49 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (0.03) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 15.0507 |
| Low Voltage Service Rate | $/kW | 0.01745 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.1968) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | (0.01737) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0900) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1496 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9743 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with the Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting. controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O.Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 2.00 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $ | (0.01) |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | (0.10) |
| Distribution Volumetric Rate | $/kW | 5.3153 |
| Low Voltage Service Rate | $/kW | 0.01702 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.1955) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.01726) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0343) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.7614 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0364 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9249 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## MicroFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand | $/kW | (0.73) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Pulling of post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Notification charge | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque charge (plus bank charges) | $ | 15.00 |
| Charge to certify cheque | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Credit card convenience charge | $ | 15.00 |
| Credit check (plus credit agency costs) | $ | 15.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment – per month | % | 1.50 |
| Late payment – per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Collection of account charge – no disconnection - after regular hours | $ | 165.00 |
| Disconnect/reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – after regular hours | $ | 415.00 |
| Install/remove load control device – during regular hours | $ | 65.00 |
| Install/remove load control device – after regular hours | $ | 185.00 |

### Other

| | | |
|---|---|---|
| Service call - customer owned equipment | $ | 30.00 |
| Service call - after regular hours | $ | 165.00 |
| Temporary service - install and remove - overhead - no transformer | $ | 500.00 |
| Temporary service - install and remove - underground - no transformer | $ | 300.00 |
| Temporary service - install and remove - overhead - with transformer | $ | 1,000.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect until August 31, 2018 | $ | 22.35 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from September 1, 2018 until December 31, 2018 | $ | 28.09 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Administrative Billing Charge | $ | 150.00 |

# Alectra Utilities Corporation
# Horizon Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly Fixed Charge, per retailer | $ | 20.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0379 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0160 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0276 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0060 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account where the electricity is supplied exclusively to single-family dwelling units for domestic or household purposes, including seasonal occupancy. This includes, but is not limited to, detached houses, one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 20.92 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.23 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.27 |
| Distribution Volumetric Rate | $/kWh | 0.0040 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0010) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0074 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall normally be classified as general service. Where service is provided to combined residential and business, or residential and agricultural, whether seasonal or all-year premises, and the wiring does not provide for separate metering, the service shall normally be classed as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 25.35 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.24 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.40 |
| Distribution Volumetric Rate | $/kWh | 0.0169 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0066 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0055 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 50 TO 699 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 700 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 126.46 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 1.21 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 2.62 |
| Distribution Volumetric Rate | $/kW | 2.8642 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0055 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-Wholesale Market Participants | $/kW | (0.3626) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0273 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.5630 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.1878 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 700 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 700 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,141.02 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 10.89 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 28.18 |
| Distribution Volumetric Rate | $/kW | 3.3250 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0067 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4225) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0317 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8743 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.3517 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand over 12 consecutive months used for billing purposes is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,748.01 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 45.33 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 119.38 |
| Distribution Volumetric Rate | $/kW | 2.5174 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.5520) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0240 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.2532 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.7181 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1.10 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.04 |
| Distribution Volumetric Rate | $/kWh | 0.0200 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0066 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0055 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STREET LIGHTING SERVICE CLASSIFICATION

All service supplied to roadway lighting equipment owned by or operated by the City of Brampton, Regional Municipality of Peel, or the Ministry of Transportation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.32 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.02 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.03 |
| Distribution Volumetric Rate | $/kW | 11.6426 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.3219) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.1112 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1341 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8215 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor’s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

| | | |
|---|---|---|
| Distribution Volumetric Rate | $/kW | 1.6931 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board, that is provided electricity by means of this distributor's facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,197.26 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 40.07 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 18.72 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8743 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.3517 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## DISTRIBUTED GENERATION [DGEN] SERVICE CLASSIFICATION

This classification applies to a distributed generator that is not a microFIT or an Energy from Waste Generator and connected to the distributor's distribution system. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 104.91 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 1.00 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.47 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0066 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0055 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## ENERGY FROM WASTE SERVICE CLASSIFICATION

This classification applies to an electricity generation facility that is not covered by a microFIT or Distributed Generation classification which produces energy from combustion of consumer waste with the capability to generate over 4,000 KW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 63.66 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor’s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | | |
| General Service less than 50 kW Classification | $/kWh | (0.0032) |
| General Service 50 to 699 kW Classification | $/kW | (0.6840) |
| General Service 700 to 4,999 kW Classification | $/kW | (0.8515) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## SPECIFIC SERVICE CHARGES

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Pulling post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Special billing service (aggregation) | $ | 125.00 |
| Special billing service (sub-metering charge per meter) | $ | 25.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Disconnect/reconnection for >300 volts - during regular hours | $ | 60.00 |
| Disconnect/reconnection for >300 volts - after regular hours | $ | 155.00 |

### Other

| | | |
|---|---|---|
| Owner requested disconnection/reconnection - during regular hours | $ | 120.00 |
| Owner requested disconnection/reconnection - after regular hours | $ | 155.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect until August 31, 2018 | $ | 22.35 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from September 1, 2018 until December 31, 2018 | $ | 28.09 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES

**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0341 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0239 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 21.63 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $ | 0.12 |
| Rate Rider for Recovery of Stranded Meter Assets (2016) – effective until September 30, 2018 | $ | 0.06 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.11 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.14 |
| Distribution Volumetric Rate | $/kWh | 0.0088 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until September 30, 2018 | | |
| Applicable only for Non-RPP Customers | $/kWh | 0.0062 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0075 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less wheose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 29.00 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Stranded Meter Assets (2016) – effective until September 30, 2018 | $ | 0.21 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.12 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.40 |
| Distribution Volumetric Rate | $/kWh | 0.0185 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until September 30, 2018<br>Applicable only for Non-RPP Customers | $/kWh | 0.0062 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kWh | 0.0002 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kWh | 0.0009 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0067 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0035 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW, both regular and interval metered. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 142.24 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.57 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 4.21 |
| Distribution Volumetric Rate | $/kW | 4.2415 |
| Low Voltage Service Rate | $/kW | 0.1589 |
| Rate Rider for Disposition of Global Adjustment Account (2016) – effective until September 30, 2018<br>Applicable only to non-RPP non-Interval Metered Customers | $/kW | 2.3303 |
| Rate Rider for Disposition of Global Adjustment Account (2016) – effective until September 30, 2018<br>Applicable only for Class B Interval Metered Customers at December 31, 2016 | $/kW | (1.6412) |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.1169 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kW | (0.1224) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0184 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-Wholesale Market Participants | $/kW | (1.1367) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.0620 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0168 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kW | 0.0796 |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | 0.0905 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6739 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3420 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.8030 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 1.4520 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 6,128.34 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 24.34 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 97.02 |
| Distribution Volumetric Rate | $/kW | 2.2623 |
| Low Voltage Service Rate | $/kW | 0.1630 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.1584 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kW | (0.1659) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (1.3235) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.0840 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0090 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.0723) |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.2305 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.4016 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

| | | |
|---|---|---|
| Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). | $/kW | 2.8334 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 8.68 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.03 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.08 |
| Distribution Volumetric Rate | $/kWh | 0.0197 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2016) – effective until September 30, 2018 Applicable only for non-RPP Customers | $/kWh | 0.0062 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0029) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kWh | 0.0002 |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0005) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0037 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2018**
**Implementation Date May 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 4.23 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.02 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.04 |
| Distribution Volumetric Rate | $/kW | 9.9582 |
| Low Voltage Service Rate | $/kW | 0.1170 |
| Rate Rider for Disposition of Global Adjustment Account (2016) – effective until September 30, 2018<br>Applicable only for non-RPP Customers | $/kW | 2.3977 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.1210 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kW | (0.1267) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (1.0740) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.0641 |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | 0.0895 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0396 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kW | (0.3850) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0778 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 0.9929 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 1.20 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 6.3791 |
| Low Voltage Service Rate | $/kW | 0.1288 |
| Rate Rider for Disposition of Global Adjustment Account (2016) – effective until September 30, 2018 Applicable Only for Non-RPP Customers | $/kW | 2.2128 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.1116 |
| Rate Rider for Disposition of Deferral/Variance Account – Power (2016) – effective until September 30, 2018 | $/kW | (0.1169) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (1.0519) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2016) – effective until September 30, 2018 | $/kW | 0.0592 |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kW | 0.0870 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0253 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.5854 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6888 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.4379 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## MicroFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

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**EB-2017-0024**

## SPECIFIC SERVICE CHARGES

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement Letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |

### Other

| | | |
|---|---|---|
| Install/remove load Control device - during regular hours | $ | 65.00 |
| Install/remove load control device - after regular hours | $ | 185.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect until August 31, 2018 | $ | 22.35 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from September 1, 2018 until December 31, 2018 | $ | 28.09 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Temporary Service install and remove - overhead - no transformer | $ | 500.00 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0369 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0266 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multifamily dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4 wire, having a nominal voltage of 120/240 volts. There shall be only one delivery point to a dwelling. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 21.61 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.60 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.16 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.17 |
| Distribution Volumetric Rate | $/kWh | 0.0035 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0002) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0076 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0071 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 43.99 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.10 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.29 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.35 |
| Distribution Volumetric Rate | $/kWh | 0.0128 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | 0.0006 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0003 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0064 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 77.48 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.93 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.51 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 2.84 |
| Distribution Volumetric Rate | $/kW | 4.6629 |
| Low Voltage Service Rate | $/kW | 0.0802 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1005 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3538) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01606) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.4585 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.1163 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0308 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.7325 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5347 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS – Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate order is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,764.42 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 44.00 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 11.65 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 16.18 |
| Distribution Volumetric Rate | $/kW | 2.3994 |
| Low Voltage Service Rate | $/kW | 0.0784 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1272 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable only for Non-Wholesale Market Participants | $/kW | (0.4465) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019<br>Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01999) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018)<br>- effective May 1, 2018 until April 30, 2019 | $/kW | 0.1410 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0598 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0158 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6436 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.4803 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 13,911.73 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 346.90 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 91.89 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 264.39 |
| Distribution Volumetric Rate | $/kW | 2.9782 |
| Low Voltage Service Rate | $/kW | 0.0838 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.4054) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.0880 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0743 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0197 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.8211 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 2.6491 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer abd will be agreed to by Alectra Utilities and the customer and may be subject to periodic monitoring of actual consumption. Eligible onmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 9.08 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.23 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.06 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.05 |
| Distribution Volumetric Rate | $/kWh | 0.0165 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 | | |
| Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0004 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0064 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per luminaire) | $ | 1.52 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.04 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of 2018 Foregone Revenue - effective May 1, 2018 until December 31, 2018 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 11.6504 |
| Low Voltage Service Rate | $/kW | 0.0580 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (0.2616) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective May 1, 2018 until April 30, 2019 Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01655) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | (33.3532) |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.2905 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect from May 1, 2018 until the effective date of the next cost of service based rate order | $/kW | 0.0770 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8924 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8329 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires Alectra Utilities to provide distribution service on a standby basis as a back-up supply to an on-site generator. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

A Standby Service Charge will be applied for a month where standby power is not provided. The applicable rate is the approved Distribution Volumetric Rate of the applicable service class and is applied to gross metered demand or contracted amount, whichever is greater. A monthly administration charge of $200, for simple metering arrangements, or $500, for complex metering arrangements, will also be applied.

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.40) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs – General Service) | $ | 25.00 |
| Income tax letter | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 12.50 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential) | $ | 20.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 10.00 |
| Special meter reads | $ | 30.00 |
| Interval meter request change | $ | 40.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 9.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 20.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary service install and remove – overhead – no transformer | $ | 400.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect until August 31, 2018 | $ | 22.35 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from September 1, 2018 until December 31, 2018 | $ | 28.09 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2018
### Implementation Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0024**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0360 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0256 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# EP-3

# ATTACH 7

# The Partial Decision and Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016) Issued December 20, 2018

Ontario

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

# PARTIAL DECISION AND ORDER

## EB-2018-0016

## ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates beginning January 1, 2019**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**Michael Janigan**
Member

**December 20, 2018**

## TABLE OF CONTENTS

# 1 INTRODUCTION AND SUMMARY

Alectra Utilities Corporation (Alectra Utilities) filed a complete application with the Ontario Energy Board (OEB) on June 7, 2018 under section 78 of the *Ontario Energy Board Act, 1998* (Act), seeking approval for changes to the rates that Alectra Utilities charges for electricity distribution, effective January 1, 2019. Under section 78 of the Act, a distributor must apply to the OEB to change the rates it charges its customers. This application covers each of the former rate zones of Enersource Hydro Mississauga Inc. (Enersource RZ), PowerStream Inc. (PowerStream RZ), Hydro One Brampton Networks Inc. (Brampton RZ), and Horizon Utilities Corporation (Horizon RZ).

Alectra Utilities provides electricity distribution services to approximately one million customers in the cities of Mississauga, Hamilton, St. Catharines, Brampton, Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan, as well as Collingwood, Stayner, Creemore and Thornbury.

Alectra Utilities asked the OEB to approve its rates for 2019 using the price-cap incentive rate-setting (Price Cap IR) mechanism for its Brampton, Enersource and PowerStream RZs and an annual adjustment for the Horizon RZ for the fifth year of the 2015 to 2019 custom incentive rate-setting (Custom IR) rate plan five-year term.

Under the Price Cap IR option, the approved rates are adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of efficiency.

Under the Custom IR option, utilities with significant operating and capital expenditure needs may apply for a multi-year Custom IR plan where rates are set for all years of the plan term, subject to specific adjustments.

The OEB makes the following findings:

- The OEB approves the annual adjustments proposed by Alectra Utilities for the Horizon Utilities RZ for year five of the five-year term of its Custom IR framework.
- The OEB approves a price-cap adjustment of 1.2% for the Brampton, Enersource and PowerStream RZs.
- The approved rates for the Horizon, Brampton, Enersource, and PowerStream RZs will be effective January 1, 2019. The new rates will be implemented February 1, 2019.

# 2 THE PROCESS

The OEB's policy for rate setting is set out in the "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (RRFE, now referred to as the RRF) and the "Handbook for Rate Applications" (Rate Handbook). The RRF provides the distributor with performance-based rate application options that support the cost effective planning and efficient operation of a distribution network. The Rate Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications.

Alectra Utilities filed an application on June 7, 2018 for 2019 rates under the Price-Cap IR of the RRF for the Brampton, Enersource and PowerStream RZs and an annual update for the Horizon RZ arising from the five-year Custom IR framework previously approved by the OEB.[1] The OEB issued a Notice of Application on July 18, 2018, inviting parties to apply for intervenor status. The Association of Major Power Consumers in Ontario (AMPCO), the Building Owners and Managers Association of Greater Toronto (BOMA), the Consumers Council of Canada (CCC), Energy Probe Research Foundation (Energy Probe), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) applied for intervenor status. AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC were granted intervenor status. OEB staff also participated in this proceeding.

The OEB issued Procedural Order No. 1 on August 10, 2018. This order established the timetable for a written interrogatory discovery process.

The OEB issued Procedural Order No. 2 on September 24, 2018. This order established a settlement conference.

A settlement conference was held on October 16, 2018 and October 17, 2018 between Alectra Utilities and the intervenors. No settlement was reached.

The OEB issued Procedural Order No. 3 on November 8, 2018, which among other matters, established procedural steps for written submissions on all issues not eligible for cost awards. OEB staff and SEC filed written submissions on November 23, 2018. Alectra Utilities filed its reply submission on November 30, 2018.

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[1] EB-2014-0002

# 3 STRUCTURE OF THE DECISION

In this Partial Decision and Order, the OEB addresses the following issues, and provides reasons for approving or denying Alectra Utilities' proposals relating to each of them:

- Horizon Rate Zone – Year 5 Custom IR update
- Incentive Rate-setting Mechanism (IRM) Model Filings for the Brampton, Enersource, and PowerStream Rate Zones
- Retail Transmission Service Rates
- Residential Rate Design
- Deferral and Variance Accounts
- Lost Revenue Adjustment Mechanism Variance Account
- Interim Rates, Effective Date, and Foregone Revenue

In the final section, the OEB addresses the steps to implement the final rates that flow from this Partial Decision and Order.

# 4 DECISION ON ISSUES

## 4.1 Horizon Rate Zone – Year 5 Custom IR update

Horizon Utilities filed a Custom IR application with the OEB in 2014[2] requesting approval of distribution rates for the five-year period from 2015 to 2019 with rates effective January 1st of each year. A partial settlement proposal was filed on September 22, 2014, which was accepted by the OEB, and a Decision and Order on the outstanding matters was subsequently issued establishing rates effective January 1, 2015.

The approved settlement proposal set out annual updates for rates to be filed for years two to five of the Custom IR term, for rates effective January 1st. The current application is the annual update for year five of the term.

The OEB-approved settlement proposal indicated that Horizon Utilities' rates would be adjusted annually for a number of items. A number of the potential adjustments to the rates for the Horizon RZ are dealt with in subsequent sections of this Partial Decision and Order because they are relevant to other rate zones. These include:

- Retail Transmission Service Rates (RTSRs)
- Residential Rate Design
- Deferral and Variance Accounts (DVAs)
- Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

The remaining annual adjustments proposed by Alectra Utilities for the Horizon RZ in 2019 are addressed below.

### Cost of Capital

Alectra Utilities stated that the annual filing had been updated for the 2018 cost of capital parameters issued by the OEB on November 29, 2017. Alectra Utilities noted that on November 22, 2018, the OEB issued its cost of capital parameters for 2019. Alectra Utilities stated that it would update these parameters, as applicable, for the

[2] EB-2014-0002

Horizon RZ when it prepares the draft rate order. OEB staff submitted that this was appropriate. No other parties expressed any concerns in this area.

**Findings**

As per the approved settlement proposal for the Custom IR framework, the OEB approves an update to the cost of capital for the Horizon RZ. Alectra Utilities is directed to apply the OEB-approved 2019 cost of capital parameters[3] in the draft rate order.

## Changes in Working Capital Allowance

Alectra Utilities made changes to the proposed working capital allowance for the Horizon RZ as a result of changes to the cost of power. Alectra Utilities updated the cost of power based on the Regulated Price Plan (RPP) Report[4] up to April 30, 2019. Alectra Utilities then increased the RPP rates and Global Adjustment (GA) by inflation, based on the Ontario Consumer Price Index averaged over the past three years, for the period May 1, 2019 to December 31, 2019. Alectra Utilities also used 2018 Uniform Transmission Rates (UTRs) and 2017 Sub-Transmission Rates (STRs).

OEB staff submitted that the update to the cost of power for working capital is consistent with the approved settlement proposal and the OEB's decision in Alectra Utilities' last application. No other party expressed any concerns on this matter.

**Findings**

As per the approved settlement proposal for the Custom IR framework, the OEB approves the update to the working capital allowance for the Horizon RZ.

## Capital Investment Variance Account

The approved settlement proposal for the Custom IR framework provided for a variance account to refund ratepayers, at the next rebasing, any difference in the revenue requirement should in-service capital additions be lower than the approved forecast. Each year, Alectra Utilities must determine the impact to revenue requirement of the

[3] Cost of Capital Parameter Updates for 2019 Cost of Service and Custom Incentive Rate-setting Applications, November 22, 2018
[4] Regulated Price Plan Price Report and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019, April 19, 2018

variance in its cumulative capital additions for the period from January 1, 2015 to the end of the relative year, as compared to the baseline.

Alectra Utilities reported 2017 capital additions of $52.4M, which are $6.8M higher than the forecast capital additions of $45.6M. Since the cumulative in-service capital additions from 2015 to 2017 were higher than the approved forecast from 2015 to 2017, no entry was proposed by Alectra Utilities for the Capital Investment Variance Account (CIVA). This differential was calculated based on Alectra Utilities' capitalization policy rather than the previous Horizon RZ's capitalization policy in place when the forecast capital additions were approved. Alectra Utilities referenced the OEB's Decision in Alectra Utilities 2018 Electricity Distribution Rates (EDR) Application[5] as the rationale for presenting capital additions based on Alectra Utilities' capitalization policy.

OEB staff submitted that any determination made by the OEB in prior rate applications with respect to the calculation of earnings sharing should not have any bearing on determining the appropriate calculation of capital additions for the purposes of the CIVA. OEB staff further submitted that for consistency, the 2017 capital additions should be calculated based on the previous Horizon RZ capitalization policy, which was used in the Custom IR application. OEB staff also noted that under either calculation, no entry is made in the CIVA for 2017.

The SEC commented on OEB staff's submission, noting that there is an interaction between the capitalization policy change and the CIVA. SEC submitted that the amount for the 2017 CIVA addition should be deferred until the capitalization policy issues are dealt with, and in particular how they interact with the Earnings Sharing Mechanism (ESM) for the Horizon RZ.

Alectra Utilities stated that it is applying the capitalization policy change consistently, both in its computation of ESM per the OEB's Decision in the Alectra Utilities 2018 EDR Application and in its statement of actual capital additions in 2017. Alectra Utilities stated that the OEB staff's submission implies that the OEB should selectively choose when it will consider and apply the changes in capitalization policy (i.e. consider capitalization changes for the earnings sharing mechanism, but ignore them for the purposes of capital additions). Alectra Utilities also stated that since neither calculation would result in an entry in the CIVA for 2017, there is no reason to defer this matter as submitted by SEC.

[5] EB-2017-0024

## Findings

The OEB finds that there is no entry for the CIVA account for 2017.

The purpose of the CIVA account is to ensure that the capital renewal strategy approved for the Horizon RZ is implemented, or funds are returned to ratepayers. If actual capital additions exceed the forecast capital additions, on a cumulative basis from 2015 to 2019, there would be no entry to the CIVA account, and no funds would be returned to customers.

The change in the capitalization policy increases the in-service capital additions for the same amount of capital work to implement the strategy. The question for the OEB is whether the capital additions for the CIVA account should be based on the capitalization policy in place at the time the Custom IR framework for the Horizon rate zone was approved, or the new post-merger capitalization policy for Alectra Utilities.

Alectra Utilities has filed information showing that whether the old or new capitalization policy is used, actual capital additions for 2017 exceed the forecast capital additions of $45,626,114.[6] While there is no 2017 entry to the CIVA account at this time, the cumulative nature of this account means that final determination of the amount to be refunded to customers does not occur until the end of the five-year term (when 2019 results are available). The OEB finds that it is appropriate to defer consideration of the actual 2017 capital additions to be used for the final computation of the CIVA account until the application for 2020 rates. The OEB has previously determined that other issues related to the change in capitalization policy will be heard in the same 2020 rate proceeding.

## Efficiency Adjustment

The approved settlement proposal for the Custom IR framework included an efficiency adjustment intended to incent the former Horizon Utilities to maintain or improve its cohort position based on the OEB's stretch factor assignments. The efficiency adjustment was to operate as a proxy stretch factor in the event that Horizon Utilities was to be placed in a less efficient cohort in any year during the Custom IR term. Horizon Utilities was in the Group III cohort in 2015 and remains in Group III for the purpose of calculating 2019 stretch factors.

[6] EB-2018-0016, Responses to OEB Staff Interrogatories, September 17, 2018 (HRZ-Staff-23)

Alectra Utilities submitted that no efficiency adjustment was appropriate. OEB staff in its submission agreed. No other party expressed any concerns on this matter.

### Findings

The OEB agrees that there should be no efficiency adjustment for the 2019 rate year. Horizon Utilities was in Group III of the OEB's efficiency benchmarking and Alectra Utilities remains in Group III as of the OEB's most recent assessment.[7]

### Special Studies Deferral Account

The approved settlement proposal for the Custom IR framework included a deferral account to record costs related to the development of a study to determine the appropriateness of the specific service charges for the Horizon RZ. Alectra Utilities confirmed that no studies had commenced and no costs had been recorded related to this matter.

No parties made submissions on this issue.

### Findings

The OEB accepts that no study costs have been incurred related to specific service charges and no entry in the deferral account is required in 2019. The OEB has policy consultations underway to review Customer Service Rules and Miscellaneous Rates and Charges. The OEB agrees it is more effective for Alectra Utilities to participate in these consultations rather than undertaking its own study.

### Street Lighting Class Revenue-to-Cost Ratio

The OEB approved rate changes in 2016[8] for the street lighting class resulting from OEB policy changes to the street lighting adjustment factor and the revenue-to-cost ratio.[9] The OEB directed Horizon Utilities to phase in the revenue-to-cost ratio changes over the Custom IR term.

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[7] *Empirical Research in Support of Incentive Rate-Setting 2017 Benchmarking Update,* August 2018
[8] EB-2015-0075, Decision and Order, December 10, 2015.
[9] "Issuance of New Cost Allocation Policy for Street Lighting Rate Class", EB-2012-0383, June 12, 2015.

Alectra Utilities requested approval to reduce the 2019 street lighting class' revenue-to-cost ratio by 6.6% to 100.0%.

OEB staff submitted that the proposed rate design was consistent with the OEB's decision on the 2016 Custom IR Update[10] and the OEB's policies[11]. No other party commented on this proposed change.

**Findings**

The OEB approves the proposed change to the revenue-to-cost ratio for the street lighting rate class in 2019, as the change is consistent with the OEB's 2016 Custom IR Update decision.[12]

## 4.2 IRM Model Filings for the Brampton, Enersource, and PowerStream Rate Zones

The OEB will first address the following issues, and provide reasons for approving Alectra Utilities' proposals relating to each of them:

- Price Cap Adjustment
- Eligible Investments for Connection of Qualifying Generation Facilities

A number of the potential adjustments to the rates for the Brampton, Enersource and PowerStream RZs are dealt with in subsequent sections of this Partial Decision and Order because in addition to being relevant to these three rate zones they are also relevant to the Horizon RZ. These include:

- Retail Transmission Service Rates
- Residential Rate Design
- Deferral and Variance Accounts
- Lost Revenue Adjustment Mechanism Variance Account

[10] EB-2015-0075, Decision and Order, December 10, 2015
[11] Issuance of New Cost Allocation Policy for Street Lighting Rate Class, June 12, 2015
[12] EB-2015-0075 Decision and Order, December 10, 2015

### Price Cap Adjustment

Alectra Utilities seeks to increase its rates for the Brampton, Enersource, and PowerStream RZs, effective January 1, 2019, based on a mechanistic rate adjustment using the OEB-approved ***inflation minus X-factor*** formula applicable to Price Cap IR applications.

The components of the Price Cap IR formula applicable to Alectra Utilities are set out in Table 4.1, below. Inserting these components into the formula results in a 1.20% increase for the Brampton, Enersource, and PowerStream RZ's rates: ***1.20% = 1.50% - (0.00% + 0.30%)***.

**Table 4.1: Annual Index IR Adjustment Formula**

| Components | | Amount |
|---|---|---|
| Inflation Factor[13] | | 1.50% |
| X-Factor | Productivity[14] | 0.00% |
| | Stretch (0.00% – 0.60%)[15] | 0.30% |

The inflation factor of 1.50% applies to all Price Cap IR applications for the 2019 rate year.

The X-factor is the sum of the productivity factor and the stretch factor. It is a productivity offset that will vary among different groupings of distributors. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors with a tangible incentive to improve efficiency or else experience declining net income.

The productivity component of the X-factor is based on industry conditions over a historical study period and applies to all Price Cap IR applications for the 2019 rate year.

[13] For 2019 Inflation factor see Ontario Energy Board 2019 Electricity Distribution Rate applications - Updates November 23, 2018.

[14] Report of the OEB – "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" EB-2010-0379, Issued November 21, 2013, corrected December 4, 2013.

[15] The stretch factor groupings are based on the Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2017 Benchmarking Update", prepared by Pacific Economics Group LLC., August 2018.

The stretch factor component of the X-factor is distributor specific. The OEB has established five stretch factor groupings, each within a range from 0.00% to 0.60%. The stretch factor assigned to any particular distributor is based on the distributor's total cost performance as benchmarked against other distributors in Ontario. The most efficient distributor would be assigned the lowest stretch factor of 0.00%. Conversely, a higher stretch factor would be applied to a less efficient distributor (in accordance with its cost performance relative to expected levels) to reflect the incremental productivity gains that the distributor is expected to achieve. The stretch factor assigned to Alectra Utilities is 0.30%.

### Findings

The OEB finds that Alectra Utilities' request for a 1.20% rate adjustment for the Brampton, Enersource, and PowerStream RZs is in accordance with the annually updated parameters set by the OEB. The adjustment is approved, and Alectra Utilities' new rates shall be effective January 1, 2019.

The adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.[16]

The OEB directs Alectra Utilities to update the 2019 inflation factor in the draft rate order reflecting this Partial Decision and Order.

### Eligible Investments for Connection of Qualifying Generation Facilities

Brampton RZ

The former Hydro One Brampton Networks Inc. filed a Distribution System Plan (DSP) as part of its 2015 cost of service application.[17] The plan included a request for funding of a Renewable Generation Connection amount to be recovered through the Independent Electricity System Operator (IESO) relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2015 to 2019.

Alectra Utilities is requesting to collect renewable generation funding of $145,922 in

[16] Price Cap IR and Annual IR Index adjustments do not apply to the following rates and charges: rate riders, rate adders, low voltage service charges, retail transmission service rates, wholesale market service rate, smart metering entity charge, rural or remote electricity rate protection charge, standard supply service – administrative charge, transformation and primary metering allowances, loss factors, specific service charges, microFIT charge, and retail service charges.
[17] EB-2014-0083

2019 from all provincial ratepayers for the Brampton RZ.

Enersource RZ

The former Enersource Hydro Mississauga Inc. filed a basic Green Energy Plan as part of its 2013 cost of service application.[18] The plan provided a forecast of the number of projects and costs related to the connection of FIT and microFIT projects until 2016. As part of this IRM application, Alectra Utilities has provided an update to the number of scheduled projects for the Enersource RZ to include 2017 actual amounts and an estimate for 2018 and 2019.

Alectra Utilities is requesting to collect renewable generation funding of $153,726 in 2019 from all provincial ratepayers for the Enersource RZ.

PowerStream RZ

The former PowerStream Inc. filed a Distribution System Plan (DSP) as part of its 2016-2020 Custom IR application[19] which included a request for funding of a Renewable Generation Connection amount to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2016 to 2020.

Alectra Utilities is requesting to collect renewable generation funding of $260,517 in 2019 from all provincial ratepayers for the PowerStream RZ.

OEB staff submitted that Alectra Utilities' renewable generation funding requests for the three rate zones were correctly calculated. No intervenor opposed Alectra Utilities' request for these cost recoveries.

### Findings

The OEB approves the proposed funding of investments for connecting renewables, which were previously approved by the OEB. The approved amounts are $145,922 for the Brampton RZ, $153,726 for the Enersource RZ and $260,517 for the PowerStream RZ.

[18] EB-2012-0033
[19] EB-2015-0003

## 4.3 Retail Transmission Service Rates

Distributors charge RTSRs to their customers to recover the amounts they pay to a transmitter, a host distributor or both for transmission services. All transmitters charge (through the IESO) Uniform Transmission Rates (UTRs) approved by the OEB to distributors connected to the transmission system. Host distributors charge host-RTSRs to distributors embedded within the host's distribution system.

All four of Alectra Utilities' rates zones are partially embedded within Hydro One Networks Inc.'s distribution system. Alectra Utilities is requesting approval to adjust the RTSRs charged to customers to reflect the rates it pays for transmission services.

OEB staff had no concerns with the data supporting the updated RTSRs proposed by Alectra Utilities for the four rate zones.

The UTRs and host-RTSRs currently charged to Alectra Utilities are included in Tables 4.2 and 4.3.

**Table 4.2: UTRs**[20]

| Current Approved UTRs (2018) | per kW |
|---|---|
| Network Service Rate | $3.61 |
| Connection Service Rates | |
| Line Connection Service Rate | $0.95 |
| Transformation Connection Service Rate | $2.34 |

**Table 4.3: Hydro One Networks Inc. Sub-Transmission Host RTSRs**[21]

| Current Approved Sub-Transmission Host RTSRs (2017) | per kW |
|---|---|
| Network Service Rate | $3.19 |
| Connection Service Rates | |
| Line Connection Service Rate | $0.77 |
| Transformation Connection Service Rate | $1.75 |

[20] Decision and Order, EB-2017-0359, February 1, 2018
[21] Decision and Order, EB-2016-0081, December 21, 2016

### Findings

Alectra Utilities' proposed adjustment to its RTSRs is approved. The RTSRs were adjusted based on the current host-RTSRs and the UTRs. The differences resulting from the approval of new 2019 UTRs and RTSRs will be captured in Accounts 1584 and 1586 for future disposition.

## 4.4 Residential Rate Design

All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB's residential rate design policy stipulates that distributors will transition residential customers to a fully fixed monthly distribution service charge over a four-year period, beginning in 2016.[22] This is the last year of the transition for the Brampton, Enersource, and Horizon RZs and, accordingly, 2019 is the final year in which the Brampton, Enersource, and Horizon RZs' rates will be adjusted upwards by more than the mechanistic adjustment alone. The Brampton, Enersource, and Horizon RZs will have transitioned to a fully fixed structure. PowerStream RZ has one more year for its transition to a fully fixed structure and is required to continue with this transition until the monthly service charge is fully fixed.

The OEB expects an applicant to apply two tests to evaluate whether mitigation of bill impacts for customers is required during the transition period. Mitigation usually takes the form of a lengthening of the transition period. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10$^{th}$ percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

Alectra Utilities confirmed that the monthly service charge was not increasing by more than $4, nor would the customer at the 10th consumption percentile of electricity consumption have a bill impact of 10% or more for the Horizon, Brampton, Enersource and PowerStream RZs.

[22] OEB Policy – "A New Distribution Rate Design for Residential Electricity Customers." EB-2012-0410, April 2, 2015

OEB staff submitted that the method used to calculate the fixed rate was in accordance with OEB policy and no mitigation is required. Intervenors did not object to Alectra Utilities' proposals on this matter.

**Findings**

The OEB finds that the approach to calculate the 2019 monthly fixed charges for the Brampton, Enersource, Horizon, and PowerStream RZs is in accordance with the OEB's residential rate design policy. The results of the monthly fixed charge, and total bill impact for low consumption residential consumers demonstrate that no mitigation is required. Alectra Utilities shall adopt this same approach in the updated Rate Generator Models to be filed with the draft rate order resulting from this Decision.

## 4.5 Deferral and Variance Accounts

In each year of an IRM term, the OEB will review a distributor's Group 1 deferral and variance accounts in order to determine whether their total balance should be disposed.[23] OEB policy requires that Group 1 accounts be disposed if they exceed (as a debit or credit) a pre-set disposition threshold of $0.001 per kWh, unless a distributor justifies why balances should not be disposed.[24] If the balance does not exceed the threshold, a distributor may elect to request disposition. The approved settlement proposal for Horizon Utilities' Custom IR framework accepted the proposal to adopt the same approach for Group 1 accounts during the Horizon Utilities' Custom IR term.

Earlier this year, the OEB suspended its approvals of Group 1 rate riders on a final basis. As stated in its letter to the sector dated July 20, 2018, the OEB will determine whether the riders will be approved on an interim basis or not approved at all (i.e. no disposition of account balances) on a case-by-case basis until further notice.[25]

Alectra Utilities included in its application a request for the disposition of Group 1 DVAs over a one-year period including carrying charges projected to December 31, 2018, for the Horizon, Brampton, Enersource, and PowerStream RZs.

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[23] Group 1 accounts track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.
[24] Report of the OEB – "Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)." EB-2008-0046, July 31, 2009.
[25] OEB letter to all rate-regulated licensed electricity distributors, *Re:* OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts, July 20, 2018.

<u>Horizon RZ</u>

The 2017 actual year-end total balance for the Horizon RZ’s Group 1 accounts including interest projected to December 31, 2018 is a credit of $8,401,287. This amount represents a total credit claim of $0.0016 per kWh, which exceeds the disposition threshold. Alectra Utilities proposed the disposition of this credit amount over a one-year period.

<u>Brampton RZ</u>

The 2017 actual year-end total balance for the Brampton RZ’s Group 1 accounts including interest projected to December 31, 2018 is a credit of $2,875,293. This amount represents a total credit claim of $0.0007 per kWh, which does not exceed the disposition threshold. Alectra Utilities elected to dispose of Group 1 account balances. Alectra Utilities proposed the disposition of this credit amount over a one-year period.

<u>Enersource RZ</u>

The 2017 actual year-end total balance for the Enersource RZ’s Group 1 accounts including interest projected to December 31, 2018 is a debit of $2,918,724. This amount represents a total debit claim of $0.0004 per kWh, which does not exceed the disposition threshold. Alectra Utilities elected to dispose of Group 1 account balances. Alectra Utilities proposed the disposition of this debit amount over a one-year period.

OEB staff noted that there was a change in the rate generator model provided on October 25, 2018 that showed there were 76 Enersource RZ transition customers instead of the 74 in the initial application. Alectra Utilities confirmed that it did not make revisions to the initial application. Alectra Utilities identified that 74 customers transitioned from Class B to Class A and two customers transitioned from Class A to Class B in 2017.

<u>PowerStream RZ</u>

The 2017 actual year-end total balance for the PowerStream RZ’s Group 1 accounts including interest projected to December 31, 2018 is a credit of $10,435,500. This amount represents a total credit claim of $0.0013 per kWh, which exceeds the disposition threshold. Alectra Utilities proposed the disposition of this credit amount over a one-year period.

OEB staff submitted that the Group 1 DVA balances for the Horizon, Brampton, Enersource, and PowerStream RZs should be disposed of on an interim basis, in accordance with the OEB letter to the sector dated July 20, 2018. Alectra Utilities submitted that the Group 1 DVA balances should be disposed on a final basis.

Alectra Utilities also noted that the interest rate for Q4 2018 was updated by the OEB on September 14, 2018. Alectra Utilities submitted that it will update the carrying charges in the draft rate order.

## Findings

The OEB approves the disposition of a credit principal balance of $8,247,932 as of December 31, 2017 for Group 1 accounts on an interim basis for the Horizon RZ.

The OEB approves the disposition of a credit principal balance of $2,848,521 as of December 31, 2017 for Group 1 accounts on an interim basis for the Brampton RZ.

The OEB approves the disposition of a debit principal balance of $2,832,756 as of December 31, 2017 for Group 1 accounts on an interim basis for the Enersource RZ.

The OEB approves the disposition of a credit principal balance of $10,410,406 as of December 31, 2017 for Group 1 accounts on an interim basis for the PowerStream RZ.

The OEB accepts Alectra Utilities explanation that the Enersource RZ had 74 customers that transitioned from Class B to Class A in 2017 and two customers that transitioned from Class B to Class A, for a total of 76 transition customers.

Disposition of the balances will be over 11 months from February 1, 2019 to December 31, 2019. Alectra Utilities shall recalculate the interest to January 31, 2019 and file revised rate riders as part of the draft rate order.

Alectra Utilities asked that its Group 1 deferral and variance account balances be disposed on a final basis. Alectra Utilities did not provide reasons why the OEB should deviate from its current policy of disposing of Group 1 accounts on an interim basis for the Brampton, Enersource or PowerStream RZs. For the Horizon RZ, Alectra Utilities submitted that it would be preferable to dispose of Group 1 balances on a final basis to provide rate certainty to ratepayers.

The OEB's policy, per the July 20, 2018 letter, stated that the OEB will not approve Group 1 rate riders on a final basis until the new standardized requirements for regulatory accounting and RPP settlements are finalized. The OEB sees no reason to deviate from its policy.

Tables 4.4, 4.5, 4.6 and 4.7 identify the principal amounts for each of the four RZs which the OEB approves for disposition.

### Table 4.4: Horizon RZ Group 1 Deferral and Variance Account Balances

| Account Name | Account Number | Principal Balance ($) A |
|---|---|---|
| LV Variance Account | 1550 | 586,395 |
| Smart Meter Entity Variance Charge | 1551 | (27,964) |
| RSVA - Wholesale Market Service Charge | 1580 | (4,605,473) |
| Variance WMS - Sub-account CBR Class B | 1580 | (55,326) |
| RSVA - Retail Transmission Network Charge | 1584 | (187,535) |
| RSVA - Retail Transmission Connection Charge | 1586 | 433,459 |
| RSVA – Power | 1588 | (4,040,810) |
| RSVA - Global Adjustment | 1589 | (350,579) |
| **Totals for all Group 1 accounts** | | (8,247,932) |

### Table 4.5: Brampton RZ Group 1 Deferral and Variance Account Balances

| Account Name | Account Number | Principal Balance ($) A |
|---|---|---|
| LV Variance Account | 1550 | 200,280 |
| Smart Meter Entity Variance Charge | 1551 | (65,889) |
| RSVA - Wholesale Market Service Charge | 1580 | (3,926,630) |
| Variance WMS - Sub-account CBR Class B | 1580 | (121,943) |
| RSVA - Retail Transmission Network Charge | 1584 | 19,930 |
| RSVA - Retail Transmission Connection Charge | 1586 | (71,372) |
| RSVA – Power | 1588 | (627,073) |
| RSVA - Global Adjustment | 1589 | 1,744,175 |
| **Totals for all Group 1 accounts** | | (2,848,521) |

### Table 4.6: Enersource RZ Group 1 Deferral and Variance Account Balances

| Account Name | Account Number | Principal Balance ($) A |
|---|---|---|
| LV Variance Account | 1550 | 2,379,788 |
| Smart Meter Entity Variance Charge | 1551 | (26,813) |
| RSVA - Wholesale Market Service Charge | 1580 | (7,283,689) |
| Variance WMS - Sub-account CBR Class B | 1580 | 35,171 |
| RSVA - Retail Transmission Network Charge | 1584 | 1,964,323 |
| RSVA - Retail Transmission Connection Charge | 1586 | 48,373 |
| RSVA – Power | 1588 | 319,684 |
| RSVA - Global Adjustment | 1589 | 5,395,918 |
| **Totals for all Group 1 accounts** | | 2,832,756 |

**Table 4.7: PowerStream RZ Group 1 Deferral and Variance Account Balances**

| Account Name | Account Number | Principal Balance ($) A |
|---|---|---|
| LV Variance Account | 1550 | 1,506,288 |
| Smart Meter Entity Variance Charge | 1551 | (389,459) |
| RSVA - Wholesale Market Service Charge | 1580 | (7,987,408) |
| Variance WMS - Sub-account CBR Class B | 1580 | (84,171) |
| RSVA - Retail Transmission Network Charge | 1584 | (6,668,761) |
| RSVA - Retail Transmission Connection Charge | 1586 | (1,010,067) |
| RSVA – Power | 1588 | (223,398) |
| RSVA - Global Adjustment | 1589 | 4,446,571 |
| **Totals for all Group 1 accounts** | | (10,410,406) |

Once the final balances with interest are approved, the balance of each of the Group 1 accounts approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595. Such transfer shall be pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors.[26] The date of the transfer must be the same as the effective date for the associated rates, which is, generally, the start of the rate year. Alectra Utilities shall ensure these adjustments are included in the reporting period ending March 31, 2019 (Quarter 1).

[26] Accounting Procedures Handbook for Electricity Distributors, effective January 1, 2012.

## 4.6 Lost Revenue Adjustment Mechanism Variance Account

Distributors have an OEB licence requirement to ensure conservation and demand management (CDM) programs are available to their customers. These programs result in reduced total energy consumption. To address the impact of the reduced consumption, OEB Policy established a Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) to capture a distributor's revenue implications resulting from differences between actual load and the last OEB-approved load forecast.[27] These differences are recorded by distributors at the rate class level.

A distributor may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of its IRM application, if the balance is deemed significant by the distributor. A request for the inclusion of lost revenues from demand response programs, as part of the LRAMVA, must be addressed through a cost of service application.[28]

Alectra Utilities requested disposition of the balances in its LRAMVAs resulting from its CDM activities as of December 31, 2016 for each of the Horizon, Brampton, Enersource, and PowerStream RZs.

For each of these four rate zones, Alectra Utilities has stated it determined the LRAMVA balance in accordance with the OEB's 2012 CDM Guidelines and 2015 CDM Guidelines. [29] Alectra Utilities completed the OEB's 2018 LRAMVA work form for each of the four rate zones. In accordance with the OEB's 2016 Updated Policy[30] on the calculation of peak demand savings, Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Horizon, Brampton, Enersource, and PowerStream RZs in its lost revenue calculation.

<u>Horizon RZ</u>

Alectra Utilities' actual savings from CDM activities were above the estimated projections used in the load forecast resulting in an under-collection from customers.

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[27] Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, April 26, 2012; and,Requirement Guidelines for Electricity Distributors Conservation and Demand Management, EB-2014-0278, December 19, 2014.
[28] Report of the Ontario Energy Board – "Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs." EB-2016-0182, May 19, 2016
[29] Conservation and Demand Management Requirement Guidelines for Electricity Distributors, EB-2014-0278, December 19, 2014
[30] Report of the Ontario Energy Board – "Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs." EB-2016-0182, May 19, 2016

Alectra Utilities' LRAMVA claim, after interrogatories, for the Horizon RZ for 2016 was a debit of $764,014, including forecasted carrying charges of $25,812 through to December 31, 2018.

OEB staff submitted that Alectra Utilities has included a larger CDM threshold in its calculation compared to the basis for which 2015 rates were set. Alectra Utilities used an LRAMVA threshold of 38.7 million kWh when the approved threshold was 19.5 million kWh.

Alectra Utilities acknowledged that it incorrectly applied a threshold of 38.7 million kWh for 2016 but submitted the correct threshold was 19.2 million kWh as originally identified in the Custom IR application.[31] Alectra Utilities also noted that it updated the interest rate for Q4 2018 to reflect the latest prescribed interest rate. The revised LRAMVA claim is a debit of $908,115 from customers.

Brampton RZ

Alectra Utilities' actual savings from CDM activities were above the estimated projections used in the load forecast resulting in an under-collection from customers. Alectra Utilities' LRAMVA claim, after interrogatories, for the Brampton RZ for 2016 was a debit of $761,361, including forecasted carrying charges of $25,735 through to December 31, 2018.

OEB staff found the Brampton RZ LRAMVA balance was calculated consistently with the LRAMVA work form and supported the request by Alectra Utilties.

Alectra Utilities also noted that it updated the interest rate for Q4 2018 to reflect the latest prescribed interest rate. The revised LRAMVA claim is a debit of $762,247 from customers.

Enersource RZ

Alectra Utilities' actual savings from CDM activities were above the estimated projections used in the load forecast resulting in an under-collection from customers. Alectra Utilities' LRAMVA claim, after interrogatories, for the Enersource RZ for 2016 was a debit of $2,008,343, including forecasted carrying charges of $67,852 through to December 31, 2018.

OEB staff found the Enersource RZ LRAMVA balance was calculated consistently with the LRAMVA work form and supported the request by Alectra Utilties but noted that

[31] EB-2014-0002

Alectra Utilties needed to update a minor inconsistency in the billed demand data for streetlights.

Alectra Utilities acknowledged the inconsistency and stated that it would update the LRAMVA work form. Alectra Utilities also noted that it updated the interest rate for Q4 2018 to reflect the latest prescribed interest rate. The revised LRAMVA claim is a debit of $2,007,600 from customers.

PowerStream RZ

Alectra Utilities' actual savings from CDM activities were above the estimated projections used in the load forecast resulting in an under-collection from customers. Alectra Utilities' LRAMVA claim, after interrogatories, for the PowerStream RZ for 2016 was a debit of $2,889,807, including forecasted carrying charges of $97,905 through to December 31, 2018.

OEB staff found the PowerStream RZ LRAMVA balance was calculated consistently with the LRAMVA work form and supported the request by Alectra Utilties.

Alectra Utilities also noted that it updated the interest rate for Q4 2018 to reflect the latest prescribed interest rate. The revised LRAMVA claim is a debit of $2,891,761 from customers.

### Findings

The OEB approves the disposition of the LRAMVA accounts for the Brampton, Enersource, and PowerStream RZs of $762,247, $2,007,600, $2,891,761 respectively. Alectra Utilities has stated that these calculations are based on the most recent and appropriate final CDM evaluation reports from the IESO. The OEB accepts Alectra Utilities update for a minor inconsistency in the billed demand data for streetlights for the Enersource RZ..

The OEB accepts Alectra Utilities correction of the threshold amount for 2016 to be used in determining the LRAMVA for the Horizon RZ. The OEB approves the use of a revised threshold amount of 19,205,046 kWh and the revised LRAMVA of $908,115.

The rate riders for the LRAMVA shall recover the approved amounts over 11 months, from February 1, 2019 to December 31, 2019. Alectra Utilities shall file updated LRAMVA work forms for each rate zone to reflect the final approved balances showing the updated interest calculation to January 31, 2019 using the 2018 fourth quarter OEB prescribed interest rate, and the revised rate riders for the 11-month recovery period.

## 4.7 Interim Rates, Effective Date, and Foregone Revenue

At the oral hearing on December 5, 2018, Alectra Utilities advised the OEB that it was in the midst of an upgrade to its customer information system (CIS) resulting from its recent merger. As a result, it was too late to implement rates for January 1, 2019, regardless of the date of this Decision. Alectra Utilities requested that its rates be effective January 1, 2019 but implemented on February 1, 2019. Alectra Utilities clarified that this request was with respect to the IRM matters for which argument has already transpired.[32]

The OEB sought comments from the intervenors at the oral hearing on December 6, 2018. None of the intervenors that were present objected to the request, given the unique situation of the CIS upgrade. CCC, who was not present, provided a comment through SEC that there should be formal submissions on this issue.

### Findings

The OEB finds that given the logistical circumstances of an upgrade to Alectra Utilities' CIS, the base rates resulting from this Decision will be effective January 1, 2019 but implemented on February 1, 2019. The OEB is satisfied that this approach is reasonable for the issues and findings included in this Decision.

Intervenors and OEB staff had the opportunity by December 17, 2018 to make written submissions on the effective date for any approved incremental capital modules rate riders, which will be decided in a subsequent OEB decision.

The OEB previously made a determination that the disposition of Group 1 deferral and variance accounts will be over 11 months, from February 1, 2019 to December 31, 2019. For retail service transmission rates, any differences between actual costs and revenue collected from customers is recorded in a variance account for future disposition. Therefore, the new RTSRs will be effective and implemented February 1, 2019. The amounts approved for Eligible Investments for Connection of Qualifying Generation Facilities for the Brampton, Enersource and PowerStream RZs are approved on an annual basis, and will be the subject of a subsequent OEB decision to determine the monthly amounts paid by the IESO to Alectra Utilities.

The rates for each of Alectra Utilities' RZs are made interim effective January 1, 2019.

The OEB will approve rate riders to recover the foregone revenue given the approved effective date and implementation date as part of the draft rate order process. The OEB

[32] EB-2018-0016, Oral Hearing Transcript, December 6, 2018, p.5

directs Alectra Utilities to file proposed rate riders for the foregone revenue in its draft rate order.

# 5 CONFIDENTIALITY REQUEST

At the oral hearing, the OEB provided an oral Decision[33] on a confidentiality request by Alectra Utilities for redacted information in the interrogatory responses to G-Staff-2 Attachments 1 to 4 and CCC-1 Attachment 1. The OEB determined that the redacted information is not relevant to this proceeding.

The OEB's determination that the information is not relevant is based on the nature of the current proceeding. Alectra Utilities' application includes IRM applications for the Brampton, Enersource and PowerStream RZs, and a Custom IR annual update for the Horizon RZ. The OEB is specifically not making a finding on whether this redacted information would be relevant or granted confidential treatment in a future rebasing rate application.

[33] EB-2018-0016, Oral Hearing Transcript, December 5, 2018, p. 2-3

# 6 IMPLEMENTATION

The OEB directs Alectra Utilities to revise the proposed rates to reflect the findings in this Partial Decision and Order and to file a draft rate order for rates to be implemented February 1, 2019 based on the effective dates determined in this Partial Decision and Order.

The OEB expects Alectra Utilities to file detailed supporting material showing the impact of this Partial Decision and Order on the rates and rate riders, including bill impacts.

# 7 ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. Alectra Utilities shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Partial Decision and Order, no later than **January 7, 2019**. Alectra Utilities shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Alectra Utilities by **January 11, 2019**. The OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.

3. Alectra Utilities shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order by **January 15, 2019**.

**DATED** at Toronto December 20, 2018

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

# EP-3

# ATTACH 8

# The Decision and Interim Rate Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016) Issued January 24, 2019

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

# DECISION AND INTERIM RATE ORDER

## EB-2018-0016

## ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates beginning January 1, 2019**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**Michael Janigan**
Member

**January 24, 2019**

# 1 INTRODUCTION AND SUMMARY

Alectra Utilities Corporation (Alectra Utilities) filed a complete application with the Ontario Energy Board (OEB) on June 7, 2018 under section 78 of the *Ontario Energy Board Act, 1998* (Act), seeking approval for changes to the rates that Alectra Utilities charges for electricity distribution, effective January 1, 2019. Under section 78 of the Act, a distributor must apply to the OEB to change the rates it charges its customers. This application covers each of the former rate zones (RZ) of Enersource Hydro Mississauga Inc. (Enersource RZ), PowerStream Inc. (PowerStream RZ), Hydro One Brampton Networks Inc. (Brampton RZ), and Horizon Utilities Corporation (Horizon RZ).

The OEB issued its Partial Decision and Order[1] (Decision) which addressed the issues related to the application that were not eligible for cost awards. The Decision established a schedule for a draft rate order (DRO) process for the Decision. The Decision also made the rates for each of Alectra Utilities' RZs interim effective January 1, 2019. The OEB established a separate schedule to address the remaining issues related to the application.

Alectra Utilities filed a DRO and OEB staff filed its comments on the DRO. Alectra Utilities filed a reply submission and revisions to models included in the DRO.

The OEB is satisfied that the DRO and its revisions accurately reflect the OEB's Decision and approves the Tariff of Rates and Charges in Schedule A. These 2019 rates are interim pending the OEB's determination of the application's remaining issues.

As a result of this Decision and Interim Rate Order, it is estimated that for a typical residential customer with an average monthly consumption of 750 kWh, the total bill impact by rate zone, before taxes, is as follows:

| Rate Zone | Total Monthly Bill ($) | Total Monthly Bill (%) |
|---|---|---|
| Enersource RZ | (0.16) | (0.15) |
| PowerStream RZ | (1.50) | (1.45) |
| Brampton RZ | (0.98) | (0.96) |
| Horizon RZ | (1.63) | (1.55) |

[1] EB-2018-0016, Partial Decision and Order, December 20, 2018

# 2 DEFERRAL AND VARIANCE ACCOUNTS

In the Decision, the OEB directed Alectra Utilities to dispose of the Global Adjustment (GA) balances over 11 months from February 1, 2019 to December 31, 2019. In Alectra Utilities' DRO, it stated that due to the limitations of its customer information system (CIS) it was unable to differentiate the 2018 GA rate rider and the 2019 GA rate rider for customers that transitioned between Class A and Class B in 2017. These customers will be responsible for paying only one of the two rate riders.

To resolve this issue, Alectra Utilities proposed to implement the 2019 GA rate riders for the affected rate classes after the expiry of the 2018 GA rate riders. To maintain the same rate rider expiry date as the other 2019 rate riders, Alectra Utilities proposed to shorten the disposition period of the 2019 GA rate riders to eight months from May 1, 2019 to December 31, 2019.

OEB staff submitted that Alectra Utilities' request was reasonable.

OEB staff also submitted that the Capacity Based Recovery (CBR) monthly payments for transitioned customers should be set to zero because the Sub-account 1580 – CBR Class B balance is to be disposed through Account 1580 WMS. In its reply, Alectra Utilities updated the incentive rate-setting mechanism (IRM) and rate generator model (RGM) models accordingly.

### Findings

The OEB approves Alectra Utilities' proposed disposition of the GA balances over eight months from May 1, 2019 to December 31, 2019. This disposition affects:

- GS 50-699 kW and GS 700-4999 kW rate classes in the Brampton RZ
- GS 50-4999 kW rate classes in the Horizon Utilities and PowerStream RZs
- GS 500-4999 kW rate class in the Enersource RZ

The OEB expects Alectra Utilities to ensure its new CIS to resolve these types of billing issues prior to the implementation of 2020 rates.

The OEB finds that no changes are required to the 2019 Tariff of Rates and Charges as a result of the IRM and RGM model updates.

# 3 IMPLEMENTATION

The new rates approved in this Decision and Interim Rate Order are to be effective January 1, 2019 and implemented on February 1, 2019, except for rate riders for the disposition of DVAs, LRAMVA, and foregone revenue. The rate riders for the DVAs, except the GA rate riders specified below, LRAMVA, and foregone revenue are effective February 1, 2019. The GA rate riders for the GS 50-699 kW and GS 700-4999 kW rate classes in the Brampton RZ, the GS 50-4999 kW rate classes in the Horizon Utilities and PowerStream RZs, and the GS 500-4999 kW rate class in the Enersource RZ have an effective and implementation date of May 1, 2019. As there will be a subsequent decision related to the application, the 2019 Tariff of Rates and Charges in Schedule A may be updated.

The OEB has made some changes to the wording of the 2019 Tariff of Rates and Charges to ensure consistency with the tariff sheets of other Ontario electricity distributors. The final approved Tariffs of Rates and Charges are attached as Schedule A to this Decision and Interim Rate Order.

# 4 RATE ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. The Tariff of Rates and Charges set out in Schedule A of this Decision and Interim Rate Order is approved. Alectra Utilities shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

**DATED** at Toronto January 24, 2019

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

# SCHEDULE A

# DECISION AND INTERIM RATE ORDER

# ALECTRA UTILITIES CORPORATION

# EB-2018-0016

# JANUARY 24, 2019

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account where the electricity is supplied exclusively to single-family dwelling units for domestic or household purposes, including seasonal occupancy. This includes, but is not limited to, detached houses, one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.30 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.23 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.05 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective February 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0014) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0063 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall normally be classified as general service. Where service is provided to combined residential and business, or residential and agricultural, whether seasonal or all-year premises, and the wiring does not provide for separate metering, the service shall normally be classed as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 25.65 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.24 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.09 |
| Distribution Volumetric Rate | $/kWh | 0.0171 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0009 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 699 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 700 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 127.98 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 1.21 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.65 |
| Distribution Volumetric Rate | $/kW | 2.8986 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective from May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0018 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0147 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4742) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0055 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3626) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0368 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0273 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.4987 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.1236 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 700 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 700 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate ride In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,154.71 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 10.89 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective February 1, 2019 until December 31, 2019 | $ | 6.63 |
| Distribution Volumetric Rate | $/kW | 3.3649 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basi | $/kWh | 0.0018 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0178 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basi | $/kW | (0.5613) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0067 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4225) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0323 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0317 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8022 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2827 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand over 12 consecutive months used for billing purposes is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate ride In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,804.99 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 45.33 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 29.43 |
| Distribution Volumetric Rate | $/kW | 2.5476 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7075) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.5520) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0587 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0240 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1716 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.6383 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1.11 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Distribution Volumetric Rate | $/kWh | 0.0202 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

All service supplied to roadway lighting equipment owned by or operated by the City of Brampton, Regional Municipality of Peel, or the Ministry of Transportation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.35 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.02 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 11.7823 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.4574) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.3219) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.1112 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0806 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7680 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

| | | |
|---|---|---|
| Distribution Volumetric Rate | $/kW | 1.7134 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board, that is provided electricity by means of this distributor's facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,247.63 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 40.07 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 4.58 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8022 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2827 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## DISTRIBUTED GENERATION [DGEN] SERVICE CLASSIFICATION

This classification applies to a distributed generator that is not a microFIT or an Energy from Waste Generator and connected to the distributor's distribution system. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 106.17 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.11 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 1.00 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 -Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## ENERGY FROM WASTE SERVICE CLASSIFICATION

This classification applies to an electricity generation facility that is not covered by a microFIT or Distributed Generation classification which produces energy from combustion of consumer waste with the capability to generate over 4,000 KW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 64.42 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
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**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | | |
| General Service less than 50 kW Classification | $/kWh | (0.0032) |
| General Service 50 to 699 kW Classification | $/kW | (0.6840) |
| General Service 700 to 4,999 kW Classification | $/kW | (0.8515) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
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**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

| | | |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Pulling post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Special billing service (aggregation) | $ | 125.00 |
| Special billing service (sub-metering charge per meter) | $ | 25.00 |
| **Non-Payment of Account** | | |
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Disconnect/reconnection for >300 volts - during regular hours | $ | 60.00 |
| Disconnect/reconnection for >300 volts - after regular hours | $ | 155.00 |
| **Other** | | |
| Owner requested disconnection/reconnection - during regular hours | $ | 120.00 |
| Owner requested disconnection/reconnection - after regular hours | $ | 155.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0341 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0239 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multifamily dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4 wire, having a nominal voltage of 120/240 volts. There shall be only one delivery point to a dwelling. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.25 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.03 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.16 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.60 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 -Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | (0.0002) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0076 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0073 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 44.52 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.10 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.29 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.10 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0130 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0006 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 78.41 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.75 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.51 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.93 |
| Distribution Volumetric Rate | $/kW | 4.7189 |
| Low Voltage Service Rate | $/kW | 0.0802 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.2394 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019<br>Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.3790) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1005 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (0.3538) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01606) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.2290 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.4585 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0308 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.1163 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.7289 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5929 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS Sub-Account CBR Class B is not applicable to wholesale market participant (WMP) customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,785.59 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 3.96 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 11.65 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 44.00 |
| Distribution Volumetric Rate | $/kW | 2.4282 |
| Low Voltage Service Rate | $/kW | 0.0784 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0026 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.3019 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4774) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1272 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (0.4465) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01999) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.1001 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.1410 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0158 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0598 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6402 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5373 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 14,078.67 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 64.34 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 91.89 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 346.90 |
| Distribution Volumetric Rate | $/kW | 3.0139 |
| Low Voltage Service Rate | $/kW | 0.0838 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.2264) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.4054) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0941 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0880 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0197 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0743 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.8174 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 2.7100 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer abd will be agreed to by Alectra Utilities and the customer and may be subject to periodic monitoring of actual consumption. Eligible onmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 9.19 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.06 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.23 |
| Distribution Volumetric Rate | $/kWh | 0.0167 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0004 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per luminaire) | $ | 1.54 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.04 |
| Distribution Volumetric Rate | $/kW | 11.7902 |
| Low Voltage Service Rate | $/kW | 0.0580 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.1460) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.2616) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01655) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (4.2132) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (33.3532) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0770 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.2905 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8899 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8750 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires Alectra Utilities to provide distribution service on a standby basis as a back-up supply to an on-site generator. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

A Standby Service Charge will be applied for a month where standby power is not provided. The applicable rate is the approved Distribution Volumetric Rate of the applicable service class and is applied to gross metered demand or contracted amount, whichever is greater. A monthly administration charge of $200, for simple metering arrangements, or $500, for complex metering arrangements, will also be applied.

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.40) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs – General Service) | $ | 25.00 |
| Income tax letter | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 12.50 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential) | $ | 20.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 10.00 |
| Special meter reads | $ | 30.00 |
| Interval meter request change | $ | 40.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 9.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 20.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary service install and remove – overhead – no transformer | $ | 400.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0360 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0256 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shal be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 26.70 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.16) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.05 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0006) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0021) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0066 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 42.29 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.25) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.17 |
| Distribution Volumetric Rate | $/kWh | 0.0109 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0005 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0059 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS Sub-Account CBR Class B is not applicable to wholesale market participant (WMP) customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 389.40 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (2.27) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 1.90 |
| Distribution Volumetric Rate | $/kW | 2.6150 |
| Low Voltage Service Rate | $/kW | 0.02169 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1080 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019<br>Applicable only for Non-Wholesale Market Participants | $/kW | (0.3086) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7411) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | (0.01730) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0153) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0575 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019)<br>- effective until December 31, 2019 | $/kW | 0.0066 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.5204 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.3873 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS Sub-Account CBR Class B is not applicable to wholesale market participant (WMP) customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24,279.37 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (142.57) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 73.30 |
| Distribution Volumetric Rate | $/kW | 1.4325 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1418 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4569) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0873 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (1.2184) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.02611) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0084) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.2338 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0205 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8791 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.7433 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5,755.85 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (33.55) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 30.84 |
| Distribution Volumetric Rate | $/kW | 0.3396 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1635 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3761) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0957 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.8640) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0020) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0049 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0065 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8791 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.7433 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

| | | |
|---|---|---|
| GS>50 Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 2.6150 |
| Large Use Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 1.4325 |
| Large Use with Dedicated Assets Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 0.3396 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 8.63 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.05) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0134 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kWh | (0.0001) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0060 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumptior is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 5.63 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.03) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 15.4416 |
| Low Voltage Service Rate | $/kW | 0.01745 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.1968) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.9482) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.01737) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0900) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0943 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9209 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled b photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions o Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 1.95 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.01) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | (0.01) |
| Distribution Volumetric Rate | $/kW | 5.1752 |
| Low Voltage Service Rate | $/kW | 0.01702 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.1955) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7288) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | (0.01726) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0343) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.7614 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 1.5975 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.9840 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8729 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand | $/kW | (0.73) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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**Customer Administration**

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Pulling of post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Notification charge | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque charge (plus bank charges) | $ | 15.00 |
| Charge to certify cheque | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Credit card convenience charge | $ | 15.00 |
| Credit check (plus credit agency costs) | $ | 15.00 |

**Non-Payment of Account**

| | | |
|---|---|---|
| Late Payment – per month | % | 1.50 |
| Late Payment – per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Collection of account charge – no disconnection - after regular hours | $ | 165.00 |
| Disconnect/reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – after regular hours | $ | 415.00 |
| Install/remove load control device – during regular hours | $ | 65.00 |
| Install/remove load control device – after regular hours | $ | 185.00 |

**Other**

| | | |
|---|---|---|
| Service call - customer owned equipment | $ | 30.00 |
| Service call - after regular hours | $ | 165.00 |
| Temporary service - install and remove - overhead - no transformer | $ | 500.00 |
| Temporary service - install and remove - underground - no transformer | $ | 300.00 |
| Temporary service - install and remove - overhead - with transformer | $ | 1,000.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Administrative Billing Charge | $ | 150.00 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly Fixed Charge, per retailer | $ | 20.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0379 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0160 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0276 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0060 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.91 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.11 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0045 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0021) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0004 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0073 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 29.35 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.08 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.12 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0187 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0007 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0009 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0065 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0035 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW, both regular and interval metered. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS Sub-Account CBR Class B is not applicable to wholesale market participant (WMP) customers. It is not applicable to WMP customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP customers that transitioned between Clas A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers that transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. The rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 143.95 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.99 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.57 |
| Distribution Volumetric Rate | $/kW | 4.2924 |
| Low Voltage Service Rate | $/kW | 0.1589 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective from May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants non-interval metered - Approved on an Interim Basis | $/kWh | 0.0043 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants Non-interval metered | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis | $/kW | (0.3230) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4296) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0184 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (1.1367) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0905 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.1073 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) -effective April 30, 2019 | $/kW | 0.0796 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0168 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6130 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3338 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.7391 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 1.4431 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 6,201.88 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 15.43 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 24.34 |
| Distribution Volumetric Rate | $/kW | 2.2894 |
| Low Voltage Service Rate | $/kW | 0.1630 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (1.2846) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.3235) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (0.0771) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (0.0723) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0090 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1569 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3931 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available i the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

| | | |
|---|---|---|
| Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). | $/kW | 2.8334 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 8.78 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0199 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0029) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0037 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 4.28 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 10.0777 |
| Low Voltage Service Rate | $/kW | 0.1170 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7463) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.0740) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0895 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (0.2379) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (0.3850) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0396 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0304 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 0.9868 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 1.21 |
| Distribution Volumetric Rate | $/kW | 6.4556 |
| Low Voltage Service Rate | $/kW | 0.1288 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7044) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.0519) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0870 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 1.3491 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.5854 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0253 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6275 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.4291 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**Customer Administration**

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement Letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

**Non-Payment of Account**

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |

**Other**

| | | |
|---|---|---|
| Install/remove load Control device - during regular hours | $ | 65.00 |
| Install/remove load control device - after regular hours | $ | 185.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Temporary Service install and remove - overhead - no transformer | $ | 500.00 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing fc each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0369 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0266 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# EP-3

# ATTACH 9

# The Decision and Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016) Issued January 31, 2019

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

# DECISION AND ORDER

## EB-2018-0016

## ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates beginning January 1, 2019**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**Michael Janigan**
Member

**January 31, 2019**

## TABLE OF CONTENTS

# 1 INTRODUCTION AND SUMMARY

Alectra Utilities Corporation (Alectra Utilities) filed a complete application with the Ontario Energy Board (OEB) on June 7, 2018 under section 78 of the *Ontario Energy Board Act, 1998* (OEB Act), seeking approval for changes to the rates that Alectra Utilities charges for electricity distribution, effective January 1, 2019. Under section 78 of the OEB Act, a distributor must apply to the OEB to change the rates it charges its customers. This application covers each of the former rate zones of Enersource Hydro Mississauga Inc. (Enersource RZ), PowerStream Inc. (PowerStream RZ), Hydro One Brampton Networks Inc. (Brampton RZ), and Horizon Utilities Corporation (Horizon RZ).

Alectra Utilities provides electricity distribution services to approximately one million customers in the cities of Mississauga, Hamilton, St. Catharines, Brampton, Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan, as well as Collingwood, Stayner, Creemore and Thornbury.

Alectra Utilities asked the OEB to approve its rates for 2019 using the price-cap incentive rate-setting (Price Cap IR) mechanism for its Brampton, Enersource and PowerStream RZs. Under the Price Cap IR mechanism, the approved rates of a utility are adjusted mechanistically each year through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of each rate zone's efficiency. Alectra Utilities' application further requested incremental capital funding for the Enersource and PowerStream RZs under the Incremental Capital Module (ICM) funding option. In approving the merger for Alectra Utilities[1], the OEB approved a deferred rebasing period ending in 2026. During the deferred rebasing period, rates continue to be set using the Price Cap IR mechanism when the current Incentive Rate-setting Mechanism (IRM) terms end.

The OEB issued its Partial Decision and Order[2] addressing the issues in the application that were not eligible for cost awards on December 20, 2018. This Decision considers the remaining issues, namely Alectra Utilities' request for ICM funding for five capital projects. The OEB approves ICM funding for the Leaking Transformer project, the York Region Rapid Transit project (YRRT), and the Bathurst Street Road Widening project. The OEB does not approve funding for the Rometown Area Overhead Rebuild project or the Barrie TS Feeder Relocation project. The OEB approves ICM funding of $26.27 million, compared to the $31.57 million proposed.

[1] EB-2016-0025, EB-2016-0360, Decision and Order, December 8, 2016
[2] EB-2018-0016, Partial Decision and Order, December 20, 2018

# 2 THE PROCESS

The OEB's policy for rate setting is set out in the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*[3] (RRFE, now referred to as the RRF), and the *Handbook for Utility Rate Applications*[4] (Rate Handbook). The RRF provides the distributor with performance-based rate application options that support the cost effective planning and efficient operation of a distribution network. The Rate Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications.

Alectra Utilities filed its rate application on June 7, 2018.[5] The OEB issued a Notice of Application on July 18, 2018, inviting parties to apply for intervenor status. The Association of Major Power Consumers in Ontario (AMPCO), the Building Owners and Managers Association of Greater Toronto (BOMA), the Consumers Council of Canada (CCC), Energy Probe Research Foundation (EP), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) applied for intervenor status. AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC were granted intervenor status. OEB staff also participated in this proceeding.

The OEB issued Procedural Order No. 1 on August 10, 2018. This order established the timetable for a written interrogatory discovery process.

The OEB issued Procedural Order No. 2 on September 24, 2018. This order made provision for a settlement conference.

A settlement conference was held on October 16, 2018 and October 17, 2018 between Alectra Utilities and the intervenors. No settlement was reached at that time.

The OEB issued Procedural Order No. 3 on November 8, 2018, which established dates for an oral hearing regarding the YRRT ICM request and Horizon RZ's Earnings Sharing Mechanism (ESM), and written submissions on all issues eligible for cost awards.[6]

During the oral hearing, Alectra Utilities and the intervenors filed a settlement proposal agreeing that the consideration of the ESM for the Horizon RZ be deferred to the 2020 rate application for regulatory efficiency. This would allow this issue to be heard at the

[3] October 18, 2012
[4] October 13, 2016
[5] EB-2014-0002
[6] Issues eligible for cost awards included the ICM requests for the Enersource and PowerStream RZs and the ESM for the Horizon RZ. Procedural Order No. 3 determined that the issue of the change in capitalization policy would be deferred to Alectra Utilities' 2020 rate application.

same time as the OEB considers the change in capitalization policy. The OEB accepted the settlement proposal.

AMPCO, BOMA, CCC, EP, SEC, VECC, and OEB staff filed written submissions on the five ICM requests on December 17, 2018.

The OEB issued a Partial Decision and Order[7] addressing the issues in the application that were not eligible for cost awards on December 20, 2018.

Alectra Utilities filed its reply submission on the ICM requests on January 9, 2019.

[7] EB-2018-0016, Partial Decision and Order, December 20, 2018

# 3 PROPOSED ICM PROJECTS

This Decision considers whether Alectra Utilities should be able to charge customers rate riders to fund specific incremental capital projects during the IRM term or deferred rebasing period.

The OEB's policy for the funding of incremental capital is set out in the *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 (ACM Report)[8] and the subsequent *Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report* (Supplemental Report) (collectively referred to as the ICM policy). The OEB provided further policy direction for the availability of incremental capital modules following a merger in the *Report of the Board Rate-Making Associated with Distributor Consolidation* (MAADs policy)[9] and in the *Handbook to Electricity Distributor and Transmitter Consolidations* (MAADs Handbook).

Alectra Utilities' application included a request for incremental funding for five ICM projects, three within the PowerStream RZ and two within the Enersource RZ.

The OEB first addresses the overall eligibility for ICM funding and the criteria that must be met for incremental capital project funding. The OEB then assesses each of the five projects.

## 3.1 Overall Eligibility for ICM Funding

As set out in the OEB's ICM policy, the ICM is a funding mechanism available to electricity distributors whose rates are established under the Price Cap IR regime, as described in Section 3.3.2 of the Filing Requirements.[10] The OEB's ICM policy does not make ICM funding available for typical annual capital programs.[11] It is also not available for projects that do not have a significant influence on the operations of the distributor.[12] The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the Price Cap IR rate-setting plan which are incremental to a

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[8] EB-2014-0219
[9] EB-2014-0138
[10] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 3 Incentive Rate-Setting Applications*, July 12, 2018 ("IRM Filing Requirements")
[11] Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219, September 18, 2014, page 13
[12] *Ibid*, p. 17

materiality threshold.[13] The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed Distribution Supply Plan. It is not limited to extraordinary or unanticipated investments.

In order to qualify for ICM funding, a request must satisfy the eligibility criteria of materiality, need and prudence, as set out in section 4.1.5 of the ACM Report. Changes to the materiality threshold were made in the Supplemental Report.[14]

## Materiality

There are two materiality tests related to ICM applications. The first test is the ICM materiality threshold formula, which serves to define the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor".[15]

Alectra Utilities calculated the materiality thresholds for the two rate zones as follows:

- Enersource RZ has a maximum eligible incremental capital amount of $36.8 million, which means that its proposal to recover $10.7 million through the ICM for this rate zone is within the OEB's acceptable range.
- PowerStream RZ has a maximum eligible incremental capital amount of $22.1 million, which means that its proposal to recover $20.9 million through the ICM for this rate zone is within the OEB's acceptable range.

No party took issue with Alectra Utilities' calculation of the ICM materiality threshold for each rate zone.

The OEB adopted a second, project-specific materiality test in the ACM Report. The project-specific materiality test is as follows:

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project

[13] *Ibid*, p. 4
[14] Supplemental Report, p. 19
[15] *ACM Report*, p. 17

> expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[16]

Alectra Utilities' application stated that each capital project was eligible for ICM funding, as each project was discrete and material.

OEB staff submitted that all of the projects met the second project-specific materiality test except for the PowerStream RZ – Barrie TS Feeder Relocation project. OEB staff indicated that this project represents 0.8% of the Alectra Utilities' total capital budget and in the OEB's decision on Alectra Utilities' 2018 ICM requests[17], the OEB did not approve projects of similar size, as they were not significant compared to the overall capital budget.

AMPCO, BOMA, CCC, EP, and SEC submitted that the Enersource RZ - Rometown Area Overhead Rebuild project and the PowerStream RZ – Barrie TS Feeder Relocation project were minor expenditures in comparison to the overall capital budget, and Alectra Utilities should be able to fund these projects through its normal capital budget.

EP also submitted that the PowerStream RZ – Bathurst Road Widening Relocation project was a minor expenditure in comparison to the overall capital budget.

SEC noted that the Enersource – Leaking Transformer project had high levels of spending in 2019 and less in the three subsequent years. SEC submitted that if Alectra Utilities balanced the spending over the four years, Alectra Utilities would be able to manage the program within its existing capital budget.

Alectra Utilities noted that the OEB has not defined the project-specific materiality threshold. Alectra Utilities submitted that there is no justification for the definition of project-specific materiality argued by OEB staff and intervenors. Alectra Utilities further submitted that it is unrealistic to expect Alectra Utilities to absorb a disallowance of $12.8 million for non-road allowance projects this year, in addition to the $27.4 million from 2018 ICM projects.

[16] ACM Report, p. 17
[17] EB-2017-0024

### Findings

The OEB accepts Alectra Utilities' calculations for the ICM materiality threshold based on the OEB's ICM formula in the ACM Report. This includes:

- Enersource RZ – maximum eligible incremental capital amount of $36.8 million
- PowerStream RZ – maximum eligible incremental capital amount of $22.1 million

This does not mean that all capital spending up to the maximum eligible incremental capital amount is eligible for incremental funding. The OEB has established other criteria so that the ICM does not become just a capital budget top-up to the ICM materiality threshold.

The OEB's findings on the project-specific materiality threshold can be found in the Eligibility of Individual Projects for ICM Funding section of this Decision.

## Need

The ACM Report indicated that need must be established by meeting the following criteria:

- passing the Means Test
- the amounts must be based on discrete projects, and should be directly related to the claimed driver
- the amounts must be clearly outside of the base upon which the rates were derived.[18]

Under the Means Test, if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, then the funding for any incremental capital project would not be allowed. Alectra Utilities submitted that based on the accounts of its predecessor utilities, it had satisfied the Means Test in each rate zone.

No party took issue with Alectra Utilities passing the Means Test.

[18] ACM Report, p. 17

**Findings**

The OEB finds that Alectra Utilities has passed the Means Test.

The question of need is further addressed in the Eligibility of Individual Projects for ICM Funding section of this Decision.

**Prudence**

The ACM Report specifies that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[19]

**Findings**

The assessment of each proposed ICM project follows in the Eligibility of Individual Projects for ICM Funding section. The OEB has not found any of the planned capital spending imprudent. The question is whether each project is eligible for incremental funding while rates are being set through an IRM mechanism.

## 3.2 Eligibility of Individual Projects for ICM Funding

### Enersource RZ – Rometown Area Overhead Rebuild Project: $3.2 million

Alectra Utilities proposed ICM funding of $3.2 million to rebuild the assets in the Rometown area. Alectra Utilities stated that through enhanced overhead system inspections it had identified a number of overhead system areas that have deteriorated and require renewal. In contrast to the 2019 Pole Replacement Program, Alectra Utilities indicated that this Rometown project targets a defined system area with known substandard assets.

AMPCO, BOMA, CCC, EP, SEC and OEB staff submitted that the project should not receive ICM funding. These parties submitted that the project should be funded through Alectra Utilities' Overhead Distribution Sustainment investments, which include ongoing work programs such as the Pole Replacement Program, Overhead Switch Sustainment Program, and Overhead Rebuild Program. Specifically, OEB staff submitted that the

[19] ACM Report, pp. 18-19

project was not discrete and the reliability data did not justify the urgency of this project. OEB staff suggested the project could be deferred or paced over an extended timeline.

In addition, AMPCO indicated that a partial rebuild of Rometown with a project cost of $1.85 million was included in the Enersource RZ Distribution Supply Plan. The project was subsequently updated to include a full replacement for a cost of $3.2 million as a result of customer consultation. AMPCO submitted that the information provided to customers for the Rometown Overhead Rebuild project was limited, and insufficient for customers to make an informed determination. For example, customers were not informed of the original plan, the $1.85 million cost, the remaining life of the poles, or reliability of the area. AMPCO was not opposed to the spending of $1.85 million and submitted that it should be funded through Alectra Utilities' normal capital budget.

BOMA, CCC, EP and VECC took issue with the extent of customer engagement and submitted it was insufficient to justify the project for ICM funding. VECC also analyzed the outage data provided for the Rometown area and found that the reliability in the Rometown area was better than the surrounding area.

In its reply submission, Alectra Utilities reiterated that the project was needed given the condition of the assets. The Rometown area had experienced several outages because of the deterioration of the overhead system assets. Alectra Utilities also indicated that the Rometown project was not included in an ongoing capital program such as the pole replacement program. Alectra Utilities also disagreed that the customer consultation was not sufficient to justify the project. Alectra Utilities modified the survey design to incorporate the issues raised from the 2017 customer engagement and gave customers the information required and bill impacts to obtain sufficient feedback.

### Findings

ICM funding is not available for typical annual capital programs. The OEB finds that the Rometown Area Overhead Rebuild project should be part of a typical annual capital program and therefore is not approved for ICM funding.

The OEB also notes that in the last rebasing application for Enersource for 2013 rates,[20] the OEB approved both a Subdivision Rebuilds and Overhead Distribution Sustainment program, and this project should reasonably be part of that typical work.

The OEB notes that a partial rebuild at a cost of $1.85 million was included in the Enersource Distribution Supply Plan filed in Alectra Utilities' 2018 rates proceeding. Alectra Utilities indicated that it increased the project from a partial rebuild of 78 poles to

[20] EB-2012-0003

a full rebuild based upon its customer engagement responses. The OEB does not find the customer engagement evidence sufficient to justify the additional capital required for the full rebuild, or to distinguish the Rometown project from other similar projects in order to receive incremental ICM funding from customers.

### Enersource RZ – Leaking Transformer Project: $7.5 million

Alectra Utilities proposed ICM funding of $7.5 million to complete a multi-year project to replace a backlog of transformers that were leaking or containing PCB oil. Alectra Utilities indicated that the 2019 project was similar to the 2018 project of $8.45 million, approved by the OEB. The 2019 project would replace the remaining backlog of 571 leaking transformers.

VECC supported ICM funding for the project. VECC submitted that Alectra Utilities had adjusted the timing for the remaining assets in need of replacement as part of its ordinary capital program.

AMPCO, BOMA, CCC, EP, SEC and OEB staff submitted that ICM funding should not be approved in 2019. Many parties referenced the OEB's 2018 decision with the OEB's expectation that this program would evolve into an ongoing capital program for transformer replacement, submitting that this evolution should begin in 2019.

Further, OEB staff noted that the OEB approved a similar ICM project in 2018 for $8.45 million and submitted that the depreciation expense being recovered could be used to fund the 2019 project.

AMPCO submitted that if the OEB approves ICM funding, the funding level should be based on the historical 5-year average unit costs and be reduced to $5.8 million.

In its reply submission, Alectra Utilities argued that OEB staff's notion that 2018 ICM funding could fund a different ICM project in a subsequent year is flawed. An ICM granted with respect to a discrete project funds only that project. Alectra Utilities also argued that it has responded to the OEB's expectation that this will evolve to be a typical ongoing capital program. Alectra Utilities stated that it plans to complete all remaining transformers in the backlog in 2019 in order to meet the OEB's expectation that the leaking transformer replacement project evolve into a typical ongoing capital program from 2020 onward.

## Findings

The OEB approves ICM funding of $7.5 million to complete the replacement of 571 transformers in 2019.

The OEB finds that approving ICM funding in 2019 is consistent with its decision for 2018 rates,[21] which approved $8.45 million, on the basis that the program is neither “typical” nor “ongoing” from the program approved by the OEB for Enersource’s 2013 rates.

The OEB finds it prudent for Alectra Utilities to complete its program to replace the backlog of leaking transformers identified in the last asset condition assessment. The OEB remains concerned about potential environmental impacts of leaking transformers and finds that ICM funding is warranted to complete the work in 2019. The OEB finds that Alectra Utilities appropriately prioritized its schedule for the program during the 2017-2019 period based on asset condition and potential environmental impacts.

Many intervenors referenced the decision for 2018 rates in which the OEB indicated that it expected this project to evolve into a typical ongoing capital program in subsequent years. The OEB finds that Alectra Utilities addressed this expectation by advancing the completion of this program to 2019 such that the ongoing capital program will commence in 2020.

## PowerStream RZ – York Region Rapid Transit Project (YRRT): $13.27 million

Alectra Utilities proposed ICM funding of $13.27 million to relocate its distribution plant to facilitate transportation infrastructure developments as part of a multi-year project to accommodate the YRRT. Alectra Utilities stated that it is obliged to relocate plant in accordance with the *Public Service Works on Highways Act* (PSWH Act) and that the OEB approved similar ICM funding in 2018.

AMPCO, CCC, SEC and OEB staff submitted that ICM funding for 2019 should be approved.

Further, OEB staff noted that Alectra Utilities’ five-year road authority budget was approximately $38.7 million and compared to the latest actual and forecasted projects has a remaining budget of $6.4 million.

[21] EB-2017-0024, Decision and Order, April 5, 2018

AMPCO, CCC, EP, and SEC noted that this work was mandatory under the PSWH Act and similar funding was approved in 2018 and should be approved in this proceeding.

OEB staff noted that cost increases appear to be caused solely by the York Region Rapid Transit Corporation (YRRTC) and submitted that Alectra Utilities should be encouraged to negotiate a different apportionment of cost responsibilities based on the YRRTC requests.

Many parties expressed concern that the overall percentage of capital contributions has decreased relative to the new project estimate and questioned if Alectra Utilities negotiated the best outcome to protect customers.

BOMA noted that the ability to negotiate was perhaps compromised by the number of municipal officials on Alectra Utilities' Board of Directors, and that Alectra Utilities did not take advantage of appealing to the Ontario Municipal Board for a higher contribution from the YRRTC. BOMA suggested that Alectra Utilities' shareholder should absorb the $6.9 million increase in budget attributable to the changes made by the YRRTC over the course of the project.

EP argued that the YRRTC is not a road authority and that the PSWH Act does not apply. EP submitted that due to the close ownership relationships between Alectra Utilities and the YRRTC, the premise that it is a road authority was not challenged by Alectra Utilities. EP suggested that the close ownership and governance relationship of Alectra Utilities and YRRTC could be viewed as an affiliate relationship. EP noted that if the YRRTC were not a road authority but an affiliate, then the YRRTC would be forced to negotiate for sharing of the costs of relocation, and it would be forced to pay more than 50% of the labour costs. EP submitted that Alectra Utilities should not pay more than 25% of the relocation costs and the OEB should only approve $6.7 million for this ICM project.

SEC submitted that the OEB should review the entire YRRT multi-year spending in Alectra Utilities' next rate application and that the OEB should direct Alectra Utilities to file a detailed forecast of the YRRT projects and a proposal for multi-year funding that balances the needs of the utility and the needs of the customers.

VECC submitted that only when the project is complete will the OEB have the opportunity to determine the prudency of the action taken by Alectra Utilities to protect itself from the cost impacts caused by third parties. VECC suggest that for this particular project the use of a deferral and variance account would be more suitable because the costs are highly variable and outside of the utility's control.

In reply submission, Alectra Utilities agreed that it may be appropriate to consider alternatives to annual ICM funding for transit projects. Alectra Utilities submitted that as permitted under the PSWH Act, it was able to persuade the YRRTC to agree to a different apportionment of the cost responsibility, where YRRTC bore a greater portion of the incremental relocation costs. Alectra Utilities disagreed with EP that Alectra Utilities and YRRTC are behaving like affiliates. Alectra Utilities noted that by EP's own submission it has acknowledged that the YRRTC and Alectra Utilities are not affiliates.

### Findings

The OEB approves the YRRT project for ICM funding of $13.27 million in 2019.

The OEB finds that approving ICM funding in 2019 is consistent with its decision for 2018 rates in which it approved $11.24 million, on the basis that the program is mandatory, material to the operations of Alectra Utilities and outside of the base upon which rates were derived.

Parties questioned whether the YRRTC is the road authority as referenced in the PSWH Act, and therefore whether the PSWH Act is applicable. The OEB finds that the cost sharing arrangement between Alectra Utilities and the YRRTC is reasonable for this project based on the evidence, but makes no specific finding with respect to the applicability of the PSWH Act.

As determined in the decision for 2018 rates, the OEB will not approve a deferral account for this project, as suggested by some intervenors. Any capital forecast is subject to uncertainty given the risks of project delays and scope changes. In any given year, an ICM rate rider may provide revenue that is over or under what the revenue would have been from the actual capital cost. This risk is mitigated as the in-service assets will be reviewed at the time of rebasing to determine if a true-up is warranted between the revenue at the forecast cost and the revenue at the actual cost.

The OEB notes that Alectra Utilities is requesting an ICM of $13.27 million in 2019 based on its initial forecast. Alectra Utilities confirmed during the oral hearing that it provided an updated forecast of $22.7 million for 2019, but did not amend its ICM request.[22] The OEB is specifically not making a finding on the appropriateness of any true-up between the forecast and the actual. However, the OEB notes that the maximum eligible incremental capital amount for the PowerStream RZ is $22.1 million,

[22] EB-2018-0016, Oral Hearing Transcript, December 5, 2018, pp. 66-67

and the OEB is approving ICMs of $18.77 million for this rate zone in 2019[23]. This may be a consideration when the OEB assesses whether a true-up is warranted.

**PowerStream RZ – Bathurst Street Road Widening Project: $5.5 million**

Alectra Utilities proposed ICM funding of $5.5 million to relocate overhead and underground distribution assets to accommodate the road widening on Bathurst Street, given growth in Richmond Hill and Vaughan. Alectra Utilities indicated that it is obligated to relocate its distribution plant to facilitate transportation infrastructure developments by applicable road authorities in accordance with the PSWH Act.

AMPCO, BOMA, CCC, SEC, VECC and OEB staff supported the approval of ICM funding for the project. Most parties submitted that this project is a discrete, mandatory project, unrelated to a recurring annual capital project. AMPCO, CCC, and VECC submitted that the use of a deferral account may be more appropriate given the inherent uncertainties related to timelines and costs for road widening projects.

**Findings**

The OEB approves the Bathurst Road Widening project for ICM funding of $5.5 million in 2019. The OEB finds that the project is mandatory, has a significant influence on the operations of the distributor and is outside of the base on which rates were set.

**PowerStream RZ – Barrie Transmission Station Feeder Relocation Project: $2.1 million**

Alectra Utilities proposed ICM funding of $2.1 million to relocate feeders to the Barrie Transmission Station (TS). The Barrie TS is owned by Hydro One and the TS rebuild was identified as part of the South Georgian Bay/Muskoka regional planning led by the Independent Electricity System Operator. Alectra Utilities noted that the need for the Barrie TS rebuild and feeder relocation was not known and not included in PowerStream's last Distribution Supply Plan.

VECC submitted that the project should be approved for ICM funding because it meets the OEB's criteria.

AMPCO, BOMA and OEB staff did not support ICM funding for this project.

[23] $18.77 million = $13.27 million + $5.5 million

AMPCO noted that Alectra Utilities did not provide the cost of other options for comparison and there is uncertainty that the 2019 in-service date will be met. There is a risk that the in-service date could be pushed to 2020 based on the most current forecast, and customers should not bear the risk if the project does not go in-service on time. AMPCO submitted that this project should be funded through Alectra Utilities normal capital budget.

BOMA submitted that it was not clear from the evidence that Alectra Utilities should be paying the entire cost of the feeder relocations. It was also unclear why the existing meters cannot be moved from the transformer station to Alectra Utilities' own enclosures to reduce cost.

OEB staff submitted the project represented 0.8% of Alectra Utilities' total capital budget and was not a significant capital cost. OEB staff referred to the OEB's 2018 decision in which the OEB did not approve funding for similar projects based on materiality. For example, the Lake/John Area Overhead Rebuild project at a cost of $0.93 million and the Station Switchgear Replacement – 8th line MS323 project at a cost of $1.39 million were both not considered a significant capital cost in comparison to the overall capital budget.

In reply submission, Alectra Utilities clarified that it was responsible for the cost of the project, the suggestion of relocating existing meters to reduce cost was not technically feasible, and the project would be completed in 2019.

### Findings

The OEB finds that this project is not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2019. The 2019 capital budget is forecast to be $257.3 million[24], and this project is 0.8% of that total. Alectra Utilities should be able to fund this project through its normal capital budget during the IRM term. No additional funding is approved.

This project does not meet the OEB's requirement that it have a significant influence on the operations of Alectra Utilities. The OEB notes that the revenue requirement related to this project is only $168,198.

[24] EB-2018-0016, Exhibit 2, Tab 4, Schedule 11, Page 13

## 3.3 Effective Date

In the oral hearing on December 6, 2018, the OEB stated that it would be helpful for the parties to provide submissions on the effective date of the ICMs.

OEB staff supported an effective date of January 1, 2019 for the ICMs as the application was filed on-time and there were minimal delays by Alectra Utilities. OEB staff also noted that if the foregone revenue rate riders calculated were immaterial then Alectra Utilities should forgo the foregone revenue, since the ICM rate rider will be collected longer than the typical IRM period and in theory would over collect on its return.

No other parties made submission on this issue.

Alectra Utilities agreed with OEB staff that the ICM riders should be effective January 1, 2019.

**Findings**

The OEB approves an effective date of March 1, 2019 for the new ICM rate riders.

The OEB acknowledges that its interim rate order decision of December 20, 2018 approved an effective date of January 1, 2019 and foregone revenue rate riders for Alectra Utilities' base rates, given the February 1, 2019 implementation date. The February 1, 2019 implementation date was necessary due to a customer information system upgrade.

The OEB does not approve a January 1, 2019 effective date and foregone revenue rate riders for the ICM based aspects of the application. An effective date of January 1, 2019 would be appropriate if all proposed capital spending was completed on January 1, 2019. That is not the case for the ICM projects approved, as capital costs will be expended throughout the year.

An ICM application is distinct from a rebasing application in which capital projects are proposed for recovery in rates. In a rebasing application, the half-year rule applies to new capital projects to account for the timing of capital expenditures in the test year. Most new capital additions come into service partway through the year and customers only receive the benefit of the capital additions once the assets enter into service.[25]

[25] The OEB confirmed that the half-year rule would continue to apply through an IRM period in the Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report, EB-2014-0219, January 22, 2016, page 10

The OEB previously determined that the half-year rule would not apply to an ICM, given the ICM rate riders would continue until the next rebasing application.

> In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan.[26]

The only exception is when the ICM starts in the year before a rebasing, when the half-year rule applies.[27]

With the ICM rate riders approved in this Decision, Alectra Utilities will collect 10 months of revenue in 2019 and a full year of revenue in 2020, and each year thereafter until rebasing. There will be no “deficiency” in the subsequent years of the plan term to address. Even with the March 1, 2019 effective date, Alectra Utilities will collect more revenue from its ICM rate riders than it would have through a rebasing application in which the half-year rule would have applied.

[26] EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors September 17, 2008, p. 31
[27] ACM Report, p. 23

# 4 IMPLEMENTATION

The OEB directs Alectra Utilities to revise the proposed ICM rate riders to reflect the findings in this Decision and Order and to file a draft rate order for rates to be implemented March 1, 2019 based on the effective dates determined in this Decision and Order. In the draft rate order, Alectra Utilities is to include detailed supporting material showing the impact of this Decision and Order on the rates and ICM rate riders, including bill impacts.

# 5 ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. Alectra Utilities shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision and Order, by **February 7, 2019**. Alectra Utilities shall also include customer rate impacts and detailed information in support of the calculation of ICM rate riders in the draft rate order.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Alectra Utilities by **February 12, 2019**. The OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.

3. Alectra Utilities shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order by **February 15, 2019**.

**DATED** at Toronto January 31, 2019

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

# EP-3

# ATTACH 10

# The Final Rate Order of the OEB in Alectra Utilities' 2019 EDR Application (EB-2018-0016) Issued February 21, 2019

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

# FINAL RATE ORDER

## EB-2018-0016

# ALECTRA UTILITIES CORPORATION

**Application for electricity distribution rates beginning January 1, 2019**

**BEFORE: Lynne Anderson**
Presiding Member

**Allison Duff**
Member

**Michael Janigan**
Member

**Feburary 21, 2019**

# 1 INTRODUCTION AND SUMMARY

Alectra Utilities Corporation (Alectra Utilities) filed a complete application with the Ontario Energy Board (OEB) on June 7, 2018 under section 78 of the *Ontario Energy Board Act, 1998* (Act), seeking approval for changes to the rates that Alectra Utilities charges for electricity distribution, effective January 1, 2019. Under section 78 of the Act, a distributor must apply to the OEB to change the rates it charges its customers. This application covers each of the former rate zones (RZ) of Enersource Hydro Mississauga Inc. (Enersource RZ), PowerStream Inc. (PowerStream RZ), Hydro One Brampton Networks Inc. (Brampton RZ), and Horizon Utilities Corporation (Horizon RZ).

On November 18, 2019, the OEB issued its Decision on Confidentiality and Procedural Order No. 3[1], which established a separate schedule to address issues eligible and not eligible for cost awards.

On December 20, 2018, the OEB issued a Partial Decision and Order, which addressed the issues not eligible for cost awards.[2] On January 18, 2019, the OEB approved an Interim Rate Order[3], pending the OEB's determination of the issues eligible for cost awards.

The OEB addressed the issues eligible for cost awards in a further Decision and Order[4] (Decision) dated January 31, 2019. The Decision established a schedule for a draft rate order (DRO) process based on the Decision.

Alectra Utilities filed a DRO on February 7, 2019, OEB staff filed its comments on February 12, 2019, and Alectra Utilities filed its reply submission on February 19, 2019. No other submissions were received.

The OEB accepts the calculations provided in the DRO. Some minor wording changes were made to the Tariff of Rates and Charges, and the approved version is attached as Schedule A.

As a result of this Final Rate Order, the total bill impact by rate zone for a typical residential customer with an average monthly consumption of 750 kWh, before taxes, is as follows:

[1] EB-2018-0016, Decision on Confidentiality and Procedural Order No. 3, November 18, 2019
[2] EB-2018-0016, Partial Decision and Order, December 20, 2018
[3] EB-2018-0016, Decision and Interim Rate Order, January 18, 2019
[4] EB-2018-0016, Decision and Order, January 31, 2019

| Rate Zone | Total Monthly Bill ($) | Total Monthly Bill (%) |
|---|---|---|
| Enersource RZ | (0.04) | (0.04) |
| PowerStream RZ | (1.32) | (1.27) |
| Brampton RZ | (0.98) | (0.96) |
| Horizon RZ | (1.63) | (1.55) |

# 2 RATE ORDER

The OEB has reviewed the information filed by Alectra Utilities and OEB staff. The OEB finds that the DRO is in accordance with the Decision. The final approved Tariff of Rates and Charges includes the rates approved in the Decision and Interim Rate Order.

The OEB has made some minor changes to the wording of the 2019 Tariff of Rates and Charges to ensure consistency with the tariff sheets of other Ontario electricity distributors. The final approved Tariff of Rates and Charges is attached as Schedule A to this Final Rate Order.

# 3 IMPLEMENTATION

In accordance with the Decision, the new ICM rate riders in the Tariff of Rates and Charges are to be implemented on March 1, 2019.

The OEB has made provisions in this Final Rate Order for eligible intervenors to file their cost claims related to this proceeding. Intervenors should only submit costs on issues eligible for cost awards as outlined in Procedural Order No. 2.[5]

[5] EB-2018-0016, Procedural Order No. 2, September 24, 2018

# 4 RATE ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. The Tariff of Rates and Charges set out in Schedule A of this Final Rate Order is approved. Alectra Utilities Corporation shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

2. Intervenors shall submit their cost claims by **February 28, 2019**.

3. Alectra Utilities Corporation may file with the OEB and forward to intervenors an objection to the claimed costs by one or more intervenors by **March 7, 2019**.

4. An intervenor whose cost claim was objected to may file with the OEB and serve on Alectra Utilities Corporation a reply submission as to why its cost claim should be allowed by **March 14, 2019**.

5. Alectra Utilities Corporation shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

**DATED** at Toronto February 21, 2019

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

# SCHEDULE A

# FINAL RATE ORDER

# ALECTRA UTILITIES CORPORATION

# EB-2018-0016

# FEBRUARY 21, 2019

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account where the electricity is supplied exclusively to single-family dwelling units for domestic or household purposes, including seasonal occupancy. This includes, but is not limited to, detached houses, one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.30 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.23 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.05 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective February 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0014) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0063 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall normally be classified as general service. Where service is provided to combined residential and business, or residential and agricultural, whether seasonal or all-year premises, and the wiring does not provide for separate metering, the service shall normally be classed as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 25.65 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.24 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.09 |
| Distribution Volumetric Rate | $/kWh | 0.0171 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0009 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 699 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 700 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers tha were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 127.98 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 1.21 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.65 |
| Distribution Volumetric Rate | $/kW | 2.8986 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective from May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0018 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0147 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4742) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0055 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3626) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0368 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0273 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.4987 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.1236 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 700 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 700 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers tha were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,154.71 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 10.89 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective February 1, 2019 until December 31, 2019 | $ | 6.63 |
| Distribution Volumetric Rate | $/kW | 3.3649 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0018 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0178 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basi | $/kW | (0.5613) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0067 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4225) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0323 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0317 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8022 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2827 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand over 12 consecutive months used for billing purposes is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers tha were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,804.99 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 45.33 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 29.43 |
| Distribution Volumetric Rate | $/kW | 2.5476 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7075) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.5520) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0587 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0240 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1716 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.6383 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1.11 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Distribution Volumetric Rate | $/kWh | 0.0202 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0010) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**

**Implementation Date February 1, 2019**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

All service supplied to roadway lighting equipment owned by or operated by the City of Brampton, Regional Municipality of Peel, or the Ministry of Transportation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.35 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.02 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 11.7823 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.4574) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.3219) |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.1112 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0806 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7680 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
## Brampton Rate Zone
### TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor’s Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis**

| | | |
|---|---|---|
| Distribution Volumetric Rate | $/kW | 1.7134 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board, that is provided electricity by means of this distributor's facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,247.63 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 40.07 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 4.58 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8022 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2827 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## DISTRIBUTED GENERATION [DGEN] SERVICE CLASSIFICATION

This classification applies to a distributed generator that is not a microFIT or an Energy from Waste Generator and connected to the distributor's distribution system. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 106.17 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.11 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 1.00 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0013 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 -Applicable only for Non-RPP Customers | $/kWh | (0.0009) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0013) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0053 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## ENERGY FROM WASTE SERVICE CLASSIFICATION

This classification applies to an electricity generation facility that is not covered by a microFIT or Distributed Generation classification which produces energy from combustion of consumer waste with the capability to generate over 4,000 KW. Further servicing details are available in the distributor’s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 64.42 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | | |
| General Service less than 50 kW Classification | $/kWh | (0.0032) |
| General Service 50 to 699 kW Classification | $/kW | (0.6840) |
| General Service 700 to 4,999 kW Classification | $/kW | (0.8515) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Pulling post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Special billing service (aggregation) | $ | 125.00 |
| Special billing service (sub-metering charge per meter) | $ | 25.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Disconnect/reconnection for >300 volts - during regular hours | $ | 60.00 |
| Disconnect/reconnection for >300 volts - after regular hours | $ | 155.00 |

### Other

| | | |
|---|---|---|
| Owner requested disconnection/reconnection - during regular hours | $ | 120.00 |
| Owner requested disconnection/reconnection - after regular hours | $ | 155.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Brampton Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0341 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0239 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multifamily dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4 wire, having a nominal voltage of 120/240 volts. There shall be only one delivery point to a dwelling. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.25 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.03 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.12 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.16 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.60 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 -Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | (0.0002) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0076 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0073 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 44.52 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.10 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.21 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.29 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.10 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0130 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0006 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 78.41 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.75 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.38 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.51 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 1.93 |
| Distribution Volumetric Rate | $/kW | 4.7189 |
| Low Voltage Service Rate | $/kW | 0.0802 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.2394 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.3790) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1005 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (0.3538) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01606) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.2290 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.4585 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0226 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0308 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.1163 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.7289 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5929 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,785.59 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 3.96 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 8.54 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 11.65 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 44.00 |
| Distribution Volumetric Rate | $/kW | 2.4282 |
| Low Voltage Service Rate | $/kW | 0.0784 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0026 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.3019 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4774) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective May 1, 2018 until April 30, 2019 | $/kW | 0.1272 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (0.4465) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01999) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.1001 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.1410 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0116 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0158 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0598 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6402 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5373 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 14,078.67 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 64.34 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 67.35 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 91.89 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 346.90 |
| Distribution Volumetric Rate | $/kW | 3.0139 |
| Low Voltage Service Rate | $/kW | 0.0838 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.2264) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.4054) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0941 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0880 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0144 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0197 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0743 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.8174 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 2.7100 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer abd will be agreed to by Alectra Utilities and the customer and may be subject to periodic monitoring of actual consumption. Eligible onmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 9.19 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.04 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.06 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.23 |
| Distribution Volumetric Rate | $/kWh | 0.0167 |
| Low Voltage Service Rate | $/kWh | 0.0002 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0004) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0004 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0071 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per luminaire) | $ | 1.54 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.01 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $ | 0.04 |
| Distribution Volumetric Rate | $/kW | 11.7902 |
| Low Voltage Service Rate | $/kW | 0.0580 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0019 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.1460) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.2616) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Non-Wholesale Market Participants Class B Customers | $/kW | (0.01655) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (4.2132) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (33.3532) |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0564 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0770 |
| Rate Rider for Recovery of Incremental Capital (2017) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.2905 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8899 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8750 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires Alectra Utilities to provide distribution service on a standby basis as a back-up supply to an on-site generator. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

A Standby Service Charge will be applied for a month where standby power is not provided. The applicable rate is the approved Distribution Volumetric Rate of the applicable service class and is applied to gross metered demand or contracted amount, whichever is greater. A monthly administration charge of $200, for simple metering arrangements, or $500, for complex metering arrangements, will also be applied.

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.40) |
| Primary Metering Allowance for transformer losses - applied to measured demand and energy | % | (1.00) |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs – General Service) | $ | 25.00 |
| Income tax letter | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 12.50 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential) | $ | 20.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 10.00 |
| Special meter reads | $ | 30.00 |
| Interval meter request change | $ | 40.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 9.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 20.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary service install and remove – overhead – no transformer | $ | 400.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |

# Alectra Utilities Corporation
# Enersource Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0360 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0256 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shal be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 26.70 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.16) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.05 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0006) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0021) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0066 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 42.29 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.25) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.17 |
| Distribution Volumetric Rate | $/kWh | 0.0109 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0005 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0059 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 389.40 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (2.27) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 1.90 |
| Distribution Volumetric Rate | $/kW | 2.6150 |
| Low Voltage Service Rate | $/kW | 0.02169 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective May 1, 2019 until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1080 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019<br>Applicable only for Non-Wholesale Market Participants | $/kW | (0.3086) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7411) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | (0.01730) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0153) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0575 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019)<br>- effective until December 31, 2019 | $/kW | 0.0066 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.5204 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.3873 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24,279.37 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (142.57) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 73.30 |
| Distribution Volumetric Rate | $/kW | 1.4325 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1418 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.4569) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0873 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (1.2184) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.02611) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0084) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.2338 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0205 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8791 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.7433 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5,755.85 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (33.55) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 30.84 |
| Distribution Volumetric Rate | $/kW | 0.3396 |
| Low Voltage Service Rate | $/kW | 0.02492 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.1635 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants | $/kW | (0.3761) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | 0.0957 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.8640) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0020) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.0049 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.0065 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8791 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.7433 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

| | | |
|---|---|---|
| GS>50 Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 2.6150 |
| Large Use Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 1.4325 |
| Large Use with Dedicated Assets Standby Charge - for a month where standby power is not provided. The charge is applied to the amount of reserved load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility. | $/kW | 0.3396 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 8.63 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.05) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0134 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kWh | (0.00005) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kWh | (0.0001) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0060 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumptior is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 5.63 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.03) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 15.4416 |
| Low Voltage Service Rate | $/kW | 0.01745 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.1968) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.9482) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019<br>Applicable Only for Class B Customers | $/kW | (0.01737) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0900) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0943 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9209 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled b photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions o Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 1.95 |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $ | (0.01) |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | (0.01) |
| Distribution Volumetric Rate | $/kW | 5.1752 |
| Low Voltage Service Rate | $/kW | 0.01702 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | (0.0029) |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | (0.0002) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.1955) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7288) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable Only for Class B Customers | $/kW | (0.01726) |
| Rate Rider for Disposition of 2016 Earnings Sharing - effective until April 30, 2019 | $/kW | (0.0343) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.7614 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 1.5975 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.9840 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8729 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand | $/kW | (0.73) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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**Customer Administration**

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Pulling of post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Notification charge | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque charge (plus bank charges) | $ | 15.00 |
| Charge to certify cheque | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Credit card convenience charge | $ | 15.00 |
| Credit check (plus credit agency costs) | $ | 15.00 |

**Non-Payment of Account**

| | | |
|---|---|---|
| Late Payment – per month | % | 1.50 |
| Late Payment – per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Collection of account charge – no disconnection - after regular hours | $ | 165.00 |
| Disconnect/reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole – after regular hours | $ | 415.00 |
| Install/remove load control device – during regular hours | $ | 65.00 |
| Install/remove load control device – after regular hours | $ | 185.00 |

**Other**

| | | |
|---|---|---|
| Service call - customer owned equipment | $ | 30.00 |
| Service call - after regular hours | $ | 165.00 |
| Temporary service - install and remove - overhead - no transformer | $ | 500.00 |
| Temporary service - install and remove - underground - no transformer | $ | 300.00 |
| Temporary service - install and remove - overhead - with transformer | $ | 1,000.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Administrative Billing Charge | $ | 150.00 |

# Alectra Utilities Corporation
# Horizon Utilities Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly Fixed Charge, per retailer | $ | 20.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0379 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0160 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0276 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0060 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.91 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.18 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.11 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0045 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0021) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0004 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0073 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 29.35 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.08 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.19 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.12 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0187 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0030) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | 0.0007 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | 0.0009 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0065 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0035 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW, both regular and interval metered. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 143.95 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.99 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.95 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.57 |
| Distribution Volumetric Rate | $/kW | 4.2924 |
| Low Voltage Service Rate | $/kW | 0.1589 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective from May 1, 2019 until December 31, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants non-interval metered - Approved on an Interim Basis | $/kWh | 0.0043 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers Non-Wholesale Market Participants Non-interval metered | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis | $/kW | (0.3230) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis | $/kW | (0.4296) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | 0.0184 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 - Applicable only for Non-Wholesale Market Participants | $/kW | (1.1367) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0905 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 0.1073 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) -effective April 30, 2019 | $/kW | 0.0796 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0282 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0168 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6130 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3338 |
| Retail Transmission Rate - Network Service Rate – Interval Metered | $/kW | 2.7391 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate – Interval Metered | $/kW | 1.4431 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 6,201.88 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 15.43 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 40.77 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 24.34 |
| Distribution Volumetric Rate | $/kW | 2.2894 |
| Low Voltage Service Rate | $/kW | 0.1630 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (1.2846) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.3235) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (0.0771) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (0.0723) |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0151 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0090 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1569 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3931 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**

**Implementation Date February 1, 2019**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available i the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS**

| | | |
|---|---|---|
| Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). | $/kW | 2.8334 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 8.78 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.02 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.06 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0199 |
| Low Voltage Service Rate | $/kWh | 0.0005 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kWh | (0.0020) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0029) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kWh | 0.0002 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kWh | (0.0005) |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0037 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 4.28 |
| Rate Rider for Recovery of 2019 Foregone Revenue - effective until December 31, 2019 | $ | 0.01 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.03 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 10.0777 |
| Low Voltage Service Rate | $/kW | 0.1170 |
| Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants - Approved on an Interim Basis | $/kWh | 0.0031 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7463) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.0740) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0895 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | (0.2379) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | (0.3850) |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0663 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0396 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0304 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 0.9868 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per Connection) | $ | 1.21 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 6.4556 |
| Low Voltage Service Rate | $/kW | 0.1288 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019<br>Applicable only for Non-RPP Customers Non-Wholesale Market Participants | $/kWh | 0.0004 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis | $/kW | (0.7044) |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.0519) |
| Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 - Applicable Only for Class B Customers | $/kW | 0.0870 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019 | $/kW | 1.3491 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until April 30, 2019 | $/kW | 0.5854 |
| Rate Rider for Recovery of Incremental Capital (2019) - in effect from March 1, 2019 until the effective date of the next cost of service based rate order | $/kW | 0.0424 |
| Rate Rider for Recovery of Incremental Capital (2018) - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0253 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6275 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.4291 |

### MONTHLY RATES AND CHARGES – Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**MONTHLY RATES AND CHARGES – Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2019
### Implementation Date February 1, 2019
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**Customer Administration**

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement Letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Account history | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

**Non-Payment of Account**

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |

**Other**

| | | |
|---|---|---|
| Install/remove load Control device - during regular hours | $ | 65.00 |
| Install/remove load control device - after regular hours | $ | 185.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - after regular hours | $ | 415.00 |
| Specific Charge for Access to the Power Poles - $/pole/year (with the exception of wireless attachments) - in effect from January 1, 2019 | $ | 43.63 |
| Temporary Service install and remove - overhead - no transformer | $ | 500.00 |

# Alectra Utilities Corporation
# PowerStream Rate Zone
## TARIFF OF RATES AND CHARGES
**Effective Date January 1, 2019**
**Implementation Date February 1, 2019**
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2018-0016**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly fixed charge, per retailer | $ | 20.00 |
| Monthly variable charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing fc each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0369 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0266 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

**EP-4**

**References.: Exhibit 2, Tab 1, Schedule 2, Page 3, Consolidated DSP; Exhibit 04, Tab 01, Schedule 01, 5.2.3 Performance Measurement for Continuous Improvement, pages 108 and 110**

**Preamble: "Alectra Utilities has experienced declining levels of reliability, both in terms of frequency and duration of outages, which are unacceptable to the company and its customers. The leading cause of this trend is defective equipment; specifically, failures of underground direct-buried cable and cable accessories. Mitigating such reliability and customer impacts through the renewal of deteriorated underground systems is a key focus for this DSP and represents approximately 25% of the capital expenditure plan."**

**Question:**

**a) Please provide in chart and table form, the Historic System Reliability Indices for each Sub- Utility/RZ and the Alectra aggregate for 2018.**

**b) For each utility/RZ please provide the historic (including 2018) Cause Codes for SAIFI and SAIDI.**

**c) Please position both the former utilities/RZs and Alectra in the Ontario SAIDI and SAIFI cohorts indicating positioning by quartile for each. Attached are Charts with 2017 data from EB-2018-0165 Toronto Hydro evidence, to assist with the response.**

**d) Please provide the historic and 2018 data for Momentary Interruptions. (MAIFI).**

**e) Please provide the MAIFI Cause Codes for 2018.**

**f) Please confirm the targets related to improved SR (SAIFI, SAIDI, MAIFI) during the term of the DSP, assuming funding is available under the requested M factor.**

**g) Why is Alectra indicating "Maintain" given the worsening reliability Trends? Discuss how this relates to Customer Preferences identified in the customer surveys. ("Innovative Research's overall finding was that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system." Page 142)**

**Response:**

a) Alectra Utilities has provided the historical system reliability indices (SAIDI and SAIFI) for each rate zone and Alectra Utilities aggregate for 2018 in Table 1 and 2, below.

**Table 1 - SAIDI (2018)**

| SAIDI (2018) | | | | |
|---|---|---|---|---|
| Rate Zone | SAIDI | SAIDI (LOS Adjusted) | SAIDI (LOS and MED Adjusted) | SAIDI (MED Adjusted) |
| ERZ | 1.72 | 1.70 | 0.92 | 0.94 |
| BRZ | 0.72 | 0.70 | 0.56 | 0.58 |
| HRZ | 2.96 | 2.56 | 1.68 | 1.01 |
| PRZ | 1.95 | 1.66 | 1.01 | 1.10 |
| GRZ | 0.50 | 0.29 | 0.26 | 0.30 |
| Alectra Utilities | 1.87 | 1.66 | 1.04 | 1.14 |

**Table 2 - SAIFI (2018)**

| SAIFI (2018) | | | | |
|---|---|---|---|---|
| Rate Zone | SAIFI | SAIFI (LOS Adjusted) | SAIFI (LOS and MED Adjusted) | SAIFI (MED Adjusted) |
| ERZ | 1.94 | 1.81 | 1.36 | 1.50 |
| BRZ | 0.94 | 0.77 | 0.71 | 0.87 |
| HRZ | 2.85 | 2.45 | 2.20 | 1.11 |
| PRZ | 1.48 | 1.32 | 1.11 | 1.24 |
| GRZ | 1.20 | 0.86 | 0.68 | 0.97 |
| Alectra Utilities | 1.80 | 1.57 | 1.33 | 1.53 |

b) Alectra Utilities has provided the historic cause codes for SAIDI and SAIFI for 2018 in Tables 3 to 21, below

**Table 3 - ERZ SAIDI by Cause Code (2014-2018)**

| ERZ - SAIDI | | | | | |
|---|---|---|---|---|---|
| Cause Code | 2014 | 2015 | 2016 | 2017 | 2018 |
| 0-Unknown/Other | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| 1-Scheduled Outage | 0.08 | 0.12 | 0.15 | 0.11 | 0.13 |
| 2-Loss of Supply | 0.00 | 0.08 | 0.04 | 0.02 | 0.02 |
| 3-Tree Contacts | 0.04 | 0.01 | 0.01 | 0.01 | 0.27 |
| 4-Lightning | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.31 | 0.37 | 0.48 | 0.34 | 0.57 |
| 6-Adverse Weather | 0.14 | 0.05 | 0.01 | 0.10 | 0.60 |
| 7-Adverse Environment | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 |
| 8-Human Element | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 |
| 9-Foreign Interference | 0.09 | 0.07 | 0.10 | 0.10 | 0.12 |
| **Total** | **0.67** | **0.72** | **0.81** | **0.71** | **1.72** |

**Table 4 - ERZ SAIDI by Cause Code (2014-2018) – MED Adjusted**

| ERZ - SAIDI MED Adjusted |
|---|

| Cause Code | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| 0-Unknown/Other | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| 1-Scheduled Outage | 0.08 | 0.12 | 0.15 | 0.11 | 0.13 |
| 2-Loss of Supply | 0.00 | 0.08 | 0.04 | 0.02 | 0.02 |
| 3-Tree Contacts | 0.03 | 0.01 | 0.01 | 0.01 | 0.04 |
| 4-Lightning | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.31 | 0.37 | 0.48 | 0.34 | 0.56 |
| 6-Adverse Weather | 0.01 | 0.05 | 0.01 | 0.01 | 0.05 |
| 7-Adverse Environment | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 |
| 8-Human Element | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 |
| 9-Foreign Interference | 0.09 | 0.07 | 0.10 | 0.10 | 0.12 |
| **Total** | **0.53** | **0.72** | **0.81** | **0.61** | **0.94** |

**Table 5 - BRZ SAIDI by Cause Code (2014-2018)**

| BRZ - SAIDI | | | | | |
|---|---|---|---|---|---|
| Cause Code | 2014 | 2015 | 2016 | 2017 | 2018 |
| 0-Unknown/Other | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 |
| 1-Scheduled Outage | 0.01 | 0.04 | 0.03 | 0.10 | 0.07 |
| 2-Loss of Supply | 0.01 | 0.04 | 0.04 | 0.01 | 0.02 |
| 3-Tree Contacts | 0.03 | 0.02 | 0.00 | 0.07 | 0.03 |
| 4-Lightning | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.27 | 0.17 | 0.19 | 0.24 | 0.39 |
| 6-Adverse Weather | 0.01 | 0.23 | 0.06 | 0.02 | 0.04 |
| 7-Adverse Environment | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 |
| 8-Human Element | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 9-Foreign Interference | 0.21 | 0.08 | 0.12 | 0.03 | 0.16 |
| **Total** | **0.57** | **0.72** | **0.45** | **0.48** | **0.72** |

**Table 6 - BRZ SAIDI by Cause Code (2014-2018) – MED Adjusted**

| BRZ - SAIDI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| Cause Code | 2014 | 2015 | 2016 | 2017 | 2018 |
| 0-Unknown/Other | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 |
| 1-Scheduled Outage | 0.01 | 0.04 | 0.03 | 0.10 | 0.07 |
| 2-Loss of Supply | 0.01 | 0.03 | 0.04 | 0.01 | 0.02 |
| 3-Tree Contacts | 0.03 | 0.02 | 0.00 | 0.01 | 0.01 |
| 4-Lightning | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.27 | 0.17 | 0.19 | 0.24 | 0.38 |
| 6-Adverse Weather | 0.01 | 0.00 | 0.06 | 0.00 | 0.00 |
| 7-Adverse Environment | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 |
| 8-Human Element | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 9-Foreign Interference | 0.02 | 0.08 | 0.12 | 0.03 | 0.08 |
| **Total** | **0.38** | **0.48** | **0.45** | **0.41** | **0.58** |

**Table 7 - HRZ SAIDI by Cause Code (2014-2018)**

| HRZ - SAIDI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.02 | 0.02 | 0.03 | 0.04 | 0.08 |
| **1-Scheduled Outage** | 0.11 | 0.12 | 0.08 | 0.13 | 0.05 |
| **2-Loss of Supply** | 0.59 | 0.08 | 0.41 | 0.11 | 0.40 |
| **3-Tree Contacts** | 0.06 | 0.23 | 0.23 | 0.20 | 0.13 |
| **4-Lightning** | 0.05 | 0.06 | 0.03 | 0.06 | 0.01 |
| **5-Defective Equipment** | 0.67 | 0.74 | 0.35 | 0.38 | 0.65 |
| **6-Adverse Weather** | 0.46 | 0.28 | 0.11 | 0.32 | 1.37 |
| **7-Adverse Environment** | 0.02 | 0.00 | 0.02 | 0.01 | 0.06 |
| **8-Human Element** | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 |
| **9-Foreign Interference** | 0.21 | 0.22 | 0.34 | 0.21 | 0.20 |
| **Total** | **2.18** | **1.77** | **1.64** | **1.47** | **2.96** |

**Table 8 - HRZ SAIDI by Cause Code (2014-2018) – MED Adjusted**

| HRZ - SAIDI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.01 | 0.02 | 0.03 | 0.04 | 0.08 |
| **1-Scheduled Outage** | 0.11 | 0.12 | 0.08 | 0.13 | 0.05 |
| **2-Loss of Supply** | 0.02 | 0.08 | 0.41 | 0.11 | 0.25 |
| **3-Tree Contacts** | 0.05 | 0.08 | 0.16 | 0.19 | 0.13 |
| **4-Lightning** | 0.05 | 0.06 | 0.03 | 0.06 | 0.01 |
| **5-Defective Equipment** | 0.49 | 0.74 | 0.35 | 0.38 | 0.65 |
| **6-Adverse Weather** | 0.08 | 0.23 | 0.06 | 0.09 | 0.48 |
| **7-Adverse Environment** | 0.02 | 0.00 | 0.02 | 0.01 | 0.06 |
| **8-Human Element** | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 |
| **9-Foreign Interference** | 0.17 | 0.22 | 0.34 | 0.21 | 0.20 |
| **Total** | **1.00** | **1.57** | **1.51** | **1.23** | **1.93** |

**Table 9 - PRZ SAIDI by Cause Code (2014-2018)**

| PRZ - SAIDI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.03 | 0.02 | 0.01 | 0.01 | 0.02 |
| **1-Scheduled Outage** | 0.14 | 0.12 | 0.11 | 0.08 | 0.08 |
| **2-Loss of Supply** | 0.06 | 0.06 | 0.81 | 0.09 | 0.28 |
| **3-Tree Contacts** | 0.10 | 0.09 | 0.12 | 0.06 | 0.12 |
| **4-Lightning** | 0.08 | 0.11 | 0.01 | 0.08 | 0.05 |
| **5-Defective Equipment** | 0.53 | 0.44 | 0.61 | 0.47 | 0.49 |
| **6-Adverse Weather** | 0.17 | 0.00 | 0.86 | 0.39 | 0.73 |
| **7-Adverse Environment** | 0.16 | 0.90 | 0.03 | 0.03 | 0.07 |
| **8-Human Element** | 0.01 | 0.04 | 0.02 | 0.01 | 0.01 |
| **9-Foreign Interference** | 0.17 | 0.21 | 0.15 | 0.22 | 0.10 |

| | | | | | |
|---|---|---|---|---|---|
| **Total** | **1.45** | **1.99** | **2.74** | **1.44** | **1.95** |

**Table 10 - PRZ SAIDI by Cause Code (2014-2018) – MED Adjusted**

| PRZ - SAIDI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.03 | 0.02 | 0.01 | 0.01 | 0.02 |
| **1-Scheduled Outage** | 0.14 | 0.12 | 0.11 | 0.08 | 0.08 |
| **2-Loss of Supply** | 0.06 | 0.01 | 0.03 | 0.09 | 0.08 |
| **3-Tree Contacts** | 0.05 | 0.09 | 0.12 | 0.05 | 0.09 |
| **4-Lightning** | 0.08 | 0.11 | 0.01 | 0.08 | 0.05 |
| **5-Defective Equipment** | 0.49 | 0.42 | 0.41 | 0.45 | 0.48 |
| **6-Adverse Weather** | 0.04 | 0.00 | 0.01 | 0.03 | 0.12 |
| **7-Adverse Environment** | 0.16 | 0.19 | 0.02 | 0.03 | 0.07 |
| **8-Human Element** | 0.01 | 0.02 | 0.02 | 0.01 | 0.01 |
| **9-Foreign Interference** | 0.17 | 0.21 | 0.15 | 0.22 | 0.10 |
| **Total** | **1.23** | **1.19** | **0.90** | **1.05** | **1.10** |

**Table 11 - GRZ SAIDI by Cause Code (2014-2018)**

| GRZ - SAIDI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.18 | 0.02 | 0.01 | 0.04 | 0.03 |
| **1-Scheduled Outage** | 0.06 | 0.07 | 0.04 | 0.07 | 0.05 |
| **2-Loss of Supply** | 0.24 | 0.11 | 0.29 | 0.10 | 0.21 |
| **3-Tree Contacts** | 0.08 | 0.02 | 0.13 | 0.01 | 0.04 |
| **4-Lightning** | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 |
| **5-Defective Equipment** | 0.06 | 0.18 | 0.34 | 0.18 | 0.08 |
| **6-Adverse Weather** | 0.00 | 0.00 | 0.18 | 0.00 | 0.06 |
| **7-Adverse Environment** | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| **8-Human Element** | 0.03 | 0.03 | 0.00 | 0.01 | 0.00 |
| **9-Foreign Interference** | 0.10 | 0.11 | 0.08 | 0.08 | 0.04 |
| **Total** | **0.75** | **0.57** | **1.08** | **0.47** | **0.50** |

**Table 12 - GRZ SAIDI by Cause Code (2014-2018) – MED Adjusted**

| GRZ - SAIDI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.18 | 0.02 | 0.01 | 0.04 | 0.01 |
| **1-Scheduled Outage** | 0.06 | 0.07 | 0.04 | 0.07 | 0.05 |
| **2-Loss of Supply** | 0.24 | 0.11 | 0.12 | 0.10 | 0.03 |
| **3-Tree Contacts** | 0.08 | 0.02 | 0.11 | 0.01 | 0.03 |
| **4-Lightning** | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 |
| **5-Defective Equipment** | 0.06 | 0.18 | 0.34 | 0.18 | 0.08 |
| **6-Adverse Weather** | 0.00 | 0.00 | 0.11 | 0.00 | 0.06 |
| **7-Adverse Environment** | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| **8-Human Element** | 0.03 | 0.03 | 0.00 | 0.01 | 0.00 |
| **9-Foreign Interference** | 0.10 | 0.11 | 0.08 | 0.08 | 0.04 |
| **Total** | **0.75** | **0.57** | **0.82** | **0.47** | **0.30** |

**Table 13 - ERZ SAIFI by Cause Code (2014-2018)**

| ERZ - SAIFI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.13 | 0.10 | 0.14 | 0.14 | 0.17 |
| **1-Scheduled Outage** | 0.03 | 0.04 | 0.04 | 0.07 | 0.04 |
| **2-Loss of Supply** | 0.01 | 0.18 | 0.10 | 0.06 | 0.14 |
| **3-Tree Contacts** | 0.06 | 0.04 | 0.01 | 0.03 | 0.10 |
| **4-Lightning** | 0.01 | 0.03 | 0.02 | 0.00 | 0.01 |
| **5-Defective Equipment** | 0.51 | 0.53 | 0.54 | 0.54 | 0.76 |
| **6-Adverse Weather** | 0.20 | 0.36 | 0.05 | 0.10 | 0.41 |
| **7-Adverse Environment** | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 |
| **8-Human Element** | 0.00 | 0.04 | 0.01 | 0.00 | 0.00 |
| **9-Foreign Interference** | 0.18 | 0.30 | 0.20 | 0.25 | 0.31 |
| **Total** | **1.13** | **1.64** | **1.13** | **1.20** | **1.94** |

**Table 14 - ERZ SAIFI by Cause Code (2014-2018) – MED Adjusted**

| ERZ - SAIFI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| 0-Unknown/Other | 0.13 | 0.10 | 0.14 | 0.14 | 0.16 |
| 1-Scheduled Outage | 0.03 | 0.04 | 0.04 | 0.07 | 0.04 |
| 2-Loss of Supply | 0.01 | 0.18 | 0.10 | 0.06 | 0.14 |
| 3-Tree Contacts | 0.05 | 0.04 | 0.01 | 0.03 | 0.02 |
| 4-Lightning | 0.01 | 0.03 | 0.02 | 0.00 | 0.01 |
| 5-Defective Equipment | 0.51 | 0.53 | 0.54 | 0.54 | 0.75 |
| 6-Adverse Weather | 0.05 | 0.36 | 0.05 | 0.04 | 0.06 |
| 7-Adverse Environment | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 |
| 8-Human Element | 0.00 | 0.04 | 0.01 | 0.00 | 0.00 |
| 9-Foreign Interference | 0.18 | 0.30 | 0.20 | 0.25 | 0.31 |
| **Total** | **0.97** | **1.64** | **1.13** | **1.14** | **1.50** |

**Table 15 - BRZ SAIFI by Cause Code (2014-2018)**

| BRZ - SAIFI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| 0-Unknown/Other | 0.08 | 0.02 | 0.09 | 0.06 | 0.10 |
| 1-Scheduled Outage | 0.00 | 0.02 | 0.01 | 0.04 | 0.02 |
| 2-Loss of Supply | 0.05 | 0.33 | 0.03 | 0.08 | 0.17 |
| 3-Tree Contacts | 0.02 | 0.07 | 0.00 | 0.03 | 0.02 |
| 4-Lightning | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.47 | 0.21 | 0.20 | 0.35 | 0.43 |
| 6-Adverse Weather | 0.04 | 0.14 | 0.21 | 0.05 | 0.02 |
| 7-Adverse Environment | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 |
| 8-Human Element | 0.10 | 0.02 | 0.00 | 0.03 | 0.01 |
| 9-Foreign Interference | 0.19 | 0.14 | 0.17 | 0.07 | 0.16 |
| **Total** | **0.95** | **1.22** | **0.72** | **0.70** | **0.94** |

**Table 16 - BRZ SAIFI by Cause Code (2014-2018) – MED Adjusted**

| BRZ - SAIDI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| 0-Unknown/Other | 0.08 | 0.02 | 0.09 | 0.06 | 0.10 |
| 1-Scheduled Outage | 0.00 | 0.02 | 0.01 | 0.04 | 0.02 |
| 2-Loss of Supply | 0.05 | 0.22 | 0.03 | 0.08 | 0.17 |
| 3-Tree Contacts | 0.02 | 0.07 | 0.00 | 0.01 | 0.02 |
| 4-Lightning | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 |
| 5-Defective Equipment | 0.47 | 0.21 | 0.20 | 0.35 | 0.42 |
| 6-Adverse Weather | 0.04 | 0.00 | 0.21 | 0.05 | 0.00 |
| 7-Adverse Environment | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 |
| 8-Human Element | 0.10 | 0.02 | 0.00 | 0.03 | 0.01 |
| 9-Foreign Interference | 0.05 | 0.14 | 0.17 | 0.07 | 0.12 |
| **Total** | **0.81** | **0.98** | **0.72** | **0.68** | **0.87** |

**Table 17 - HRZ SAIFI by Cause Code (2014-2018)**

| HRZ - SAIFI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.15 | 0.21 | 0.24 | 0.17 | 0.80 |
| **1-Scheduled Outage** | 0.05 | 0.04 | 0.03 | 0.04 | 0.02 |
| **2-Loss of Supply** | 0.27 | 0.33 | 0.36 | 0.22 | 0.40 |
| **3-Tree Contacts** | 0.10 | 0.08 | 0.16 | 0.15 | 0.09 |
| **4-Lightning** | 0.15 | 0.08 | 0.05 | 0.07 | 0.02 |
| **5-Defective Equipment** | 0.47 | 0.46 | 0.35 | 0.35 | 0.45 |
| **6-Adverse Weather** | 0.25 | 0.29 | 0.09 | 0.32 | 0.53 |
| **7-Adverse Environment** | 0.00 | 0.00 | 0.01 | 0.01 | 0.05 |
| **8-Human Element** | 0.03 | 0.02 | 0.04 | 0.04 | 0.04 |
| **9-Foreign Interference** | 0.44 | 0.41 | 0.65 | 0.49 | 0.45 |
| **Total** | **1.91** | **1.92** | **1.98** | **1.86** | **2.85** |

**Table 18 - HRZ SAIFI by Cause Code (2014-2018) – MED Adjusted**

| HRZ - SAIFI Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.15 | 0.21 | 0.24 | 0.17 | 0.80 |
| **1-Scheduled Outage** | 0.05 | 0.04 | 0.03 | 0.04 | 0.02 |
| **2-Loss of Supply** | 0.06 | 0.33 | 0.35 | 0.22 | 0.34 |
| **3-Tree Contacts** | 0.09 | 0.05 | 0.14 | 0.15 | 0.09 |
| **4-Lightning** | 0.15 | 0.08 | 0.05 | 0.07 | 0.02 |
| **5-Defective Equipment** | 0.44 | 0.46 | 0.35 | 0.35 | 0.45 |
| **6-Adverse Weather** | 0.10 | 0.27 | 0.06 | 0.20 | 0.29 |
| **7-Adverse Environment** | 0.00 | 0.00 | 0.01 | 0.01 | 0.05 |
| **8-Human Element** | 0.03 | 0.02 | 0.04 | 0.04 | 0.04 |
| **9-Foreign Interference** | 0.39 | 0.41 | 0.65 | 0.49 | 0.45 |
| **Total** | **1.48** | **1.86** | **1.93** | **1.74** | **2.54** |

**Table 19 - PRZ SAIFI by Cause Code (2014-2018)**

| PRZ - SAIFI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.12 | 0.15 | 0.06 | 0.18 | 0.15 |
| **1-Scheduled Outage** | 0.05 | 0.04 | 0.05 | 0.03 | 0.03 |
| **2-Loss of Supply** | 0.07 | 0.10 | 0.08 | 0.08 | 0.17 |
| **3-Tree Contacts** | 0.11 | 0.10 | 0.10 | 0.02 | 0.07 |
| **4-Lightning** | 0.15 | 0.10 | 0.03 | 0.08 | 0.10 |
| **5-Defective Equipment** | 0.56 | 0.31 | 0.51 | 0.41 | 0.46 |
| **6-Adverse Weather** | 0.22 | 0.01 | 0.33 | 0.22 | 0.33 |
| **7-Adverse Environment** | 0.12 | 0.48 | 0.04 | 0.03 | 0.05 |
| **8-Human Element** | 0.06 | 0.05 | 0.02 | 0.02 | 0.04 |
| **9-Foreign Interference** | 0.25 | 0.17 | 0.19 | 0.27 | 0.08 |
| **Total** | **1.71** | **1.52** | **1.41** | **1.35** | **1.48** |

**Table 20 - PRZ SAIFI by Cause Code (2014-2018) – MED Adjusted**

| PRZ - SAIFI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.12 | 0.15 | 0.06 | 0.18 | 0.15 |
| **1-Scheduled Outage** | 0.05 | 0.04 | 0.05 | 0.03 | 0.03 |
| **2-Loss of Supply** | 0.05 | 0.03 | 0.03 | 0.07 | 0.13 |
| **3-Tree Contacts** | 0.08 | 0.10 | 0.10 | 0.02 | 0.07 |
| **4-Lightning** | 0.15 | 0.10 | 0.03 | 0.08 | 0.10 |
| **5-Defective Equipment** | 0.51 | 0.31 | 0.41 | 0.40 | 0.45 |
| **6-Adverse Weather** | 0.09 | 0.01 | 0.04 | 0.06 | 0.14 |
| **7-Adverse Environment** | 0.12 | 0.17 | 0.04 | 0.03 | 0.05 |
| **8-Human Element** | 0.06 | 0.04 | 0.02 | 0.02 | 0.04 |
| **9-Foreign Interference** | 0.25 | 0.17 | 0.19 | 0.27 | 0.08 |
| **Total** | **1.48** | **1.14** | **0.96** | **1.16** | **1.24** |

**Table 21 - GRZ SAIFI by Cause Code (2014-2018)**

| GRZ - SAIFI | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.31 | 0.12 | 0.02 | 0.24 | 0.14 |
| **1-Scheduled Outage** | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 |
| **2-Loss of Supply** | 0.27 | 0.29 | 0.78 | 0.26 | 0.34 |
| **3-Tree Contacts** | 0.16 | 0.05 | 0.14 | 0.00 | 0.13 |
| **4-Lightning** | 0.13 | 0.07 | 0.00 | 0.00 | 0.00 |
| **5-Defective Equipment** | 0.10 | 0.49 | 0.39 | 0.38 | 0.17 |
| **6-Adverse Weather** | 0.00 | 0.00 | 0.23 | 0.02 | 0.19 |
| **7-Adverse Environment** | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 |
| **8-Human Element** | 0.05 | 0.11 | 0.00 | 0.05 | 0.00 |
| **9-Foreign Interference** | 0.26 | 0.35 | 0.61 | 0.32 | 0.20 |
| **Total** | **1.30** | **1.53** | **2.19** | **1.30** | **1.20** |

**Table 22 - GRZ SAIFI by Cause Code (2014-2018) – MED Adjusted**

| GRZ - SAIFI MED Adjusted | | | | | |
|---|---|---|---|---|---|
| **Cause Code** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **0-Unknown/Other** | 0.31 | 0.12 | 0.02 | 0.24 | 0.03 |
| **1-Scheduled Outage** | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 |
| **2-Loss of Supply** | 0.27 | 0.29 | 0.61 | 0.26 | 0.29 |
| **3-Tree Contacts** | 0.16 | 0.05 | 0.14 | 0.00 | 0.13 |
| **4-Lightning** | 0.13 | 0.07 | 0.00 | 0.00 | 0.00 |
| **5-Defective Equipment** | 0.10 | 0.49 | 0.39 | 0.38 | 0.13 |
| **6-Adverse Weather** | 0.00 | 0.00 | 0.16 | 0.02 | 0.16 |
| **7-Adverse Environment** | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 |
| **8-Human Element** | 0.05 | 0.11 | 0.00 | 0.05 | 0.00 |
| **9-Foreign Interference** | 0.26 | 0.35 | 0.61 | 0.32 | 0.20 |
| **Total** | **1.30** | **1.53** | **1.95** | **1.30** | **0.97** |

c) Alectra Utilities has updated the chart provided in EB-2018-0165 as Figure 1 and Figure 2, below. A breakdown of SAIDI and SAIFI by quartile is provided in Tables 23 to 24, below.

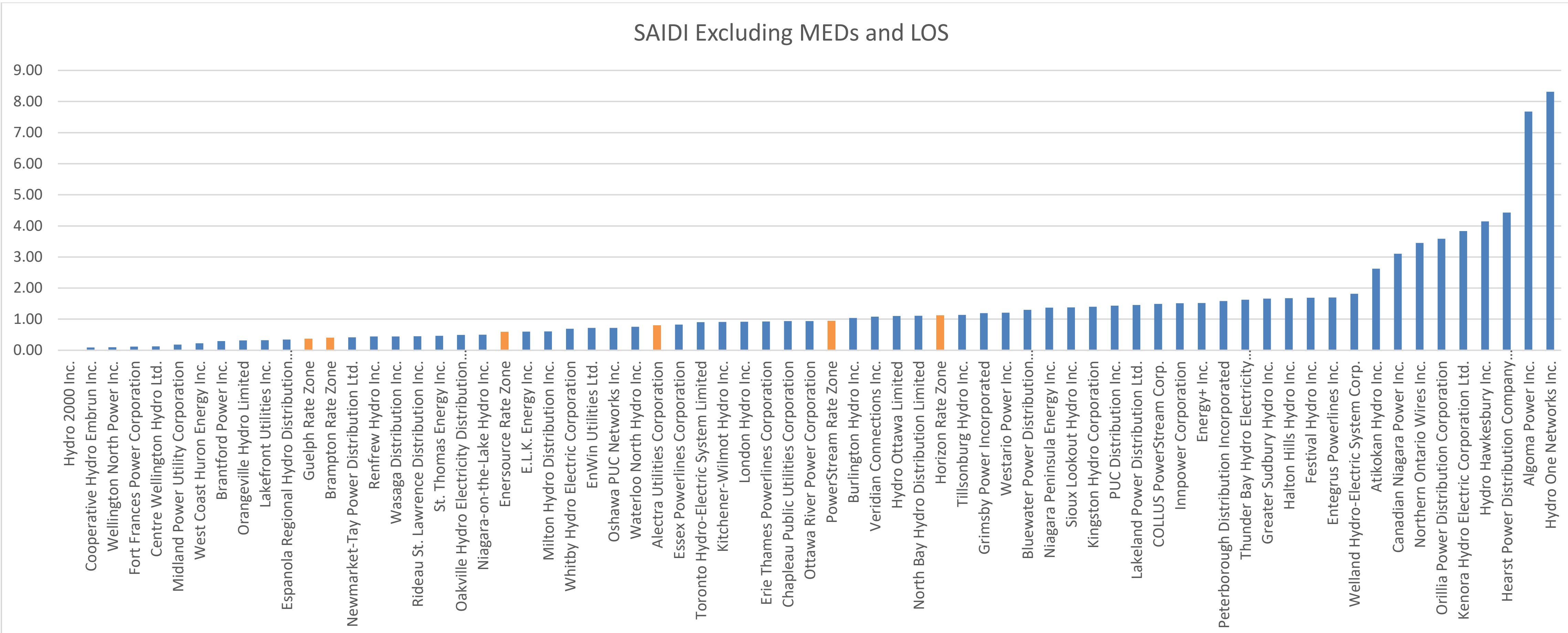


**Figure 1: SAIDI Excluding MEDS and LOS**

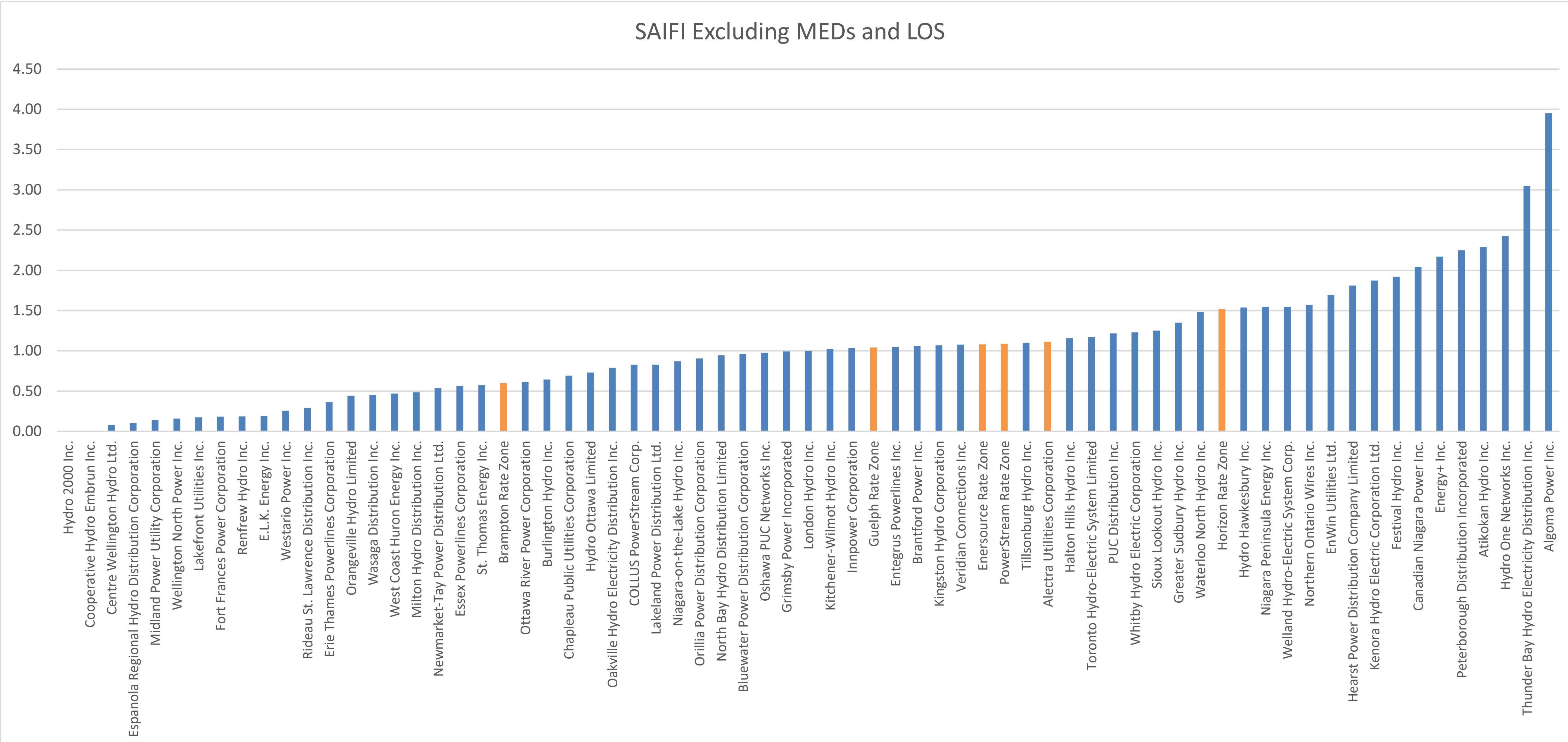


**Figure 2: SAIFI Excluding MEDS and LOS**

**Table 23 - SAIFI Quartile Grouping**

| Quartile | SAIFI |
|---|---|
| Q1 | None |
| Q2 | BRZ |
| Q3 | GRZ, ERZ, PRZ, Alectra |
| Q4 | HRZ |

**Table 24 - SAIDI Quartile Grouping**

| Quartile | SAIDI |
|---|---|
| Q1 | BRZ, GRZ |
| Q2 | ERZ, Alectra |
| Q3 | PRZ and HRZ |
| Q4 | None |

d) Alectra Utilities' historical and 2018 MAIFI is provide in Table EP-4d.

**Table 25 - Alectra Utilities MAIFI (2014-2018)**

| | Alectra | | | | |
|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 |
| MAIFI | 3.49 | 3.92 | 3.31 | 3.18 | 3.53 |

e) Alectra Utilities' MAIFI by cause code for 2018 is provided in Table EP-4e.

**Table 26 - Alectra Utilities 2018 MAIFI by Cause Code**

| 2018 Alectra MAIFI by Cause Code | | | |
|---|---|---|---|
| Cause Code | # of Event | # of Customer Interruptions | MAIFI |
| 0-Unknown/Other | 763 | 1,393,766 | 1.33 |
| 1-Scheduled Outage | 14 | 357 | 0.00 |
| 2-Loss of Supply | 21 | 23,946 | 0.02 |
| 3-Tree Contacts | 31 | 29,623 | 0.03 |
| 4-Lightning | 102 | 229,865 | 0.22 |
| 5-Defective Equipment | 412 | 811,366 | 0.78 |
| 6-Adverse Weather | 285 | 491,142 | 0.47 |
| 7-Adverse Environment | 10 | 10,340 | 0.01 |
| 8-Human Element | 8 | 7,085 | 0.01 |
| 9-Foreign Interference | 446 | 692,740 | 0.66 |
| **Total** | **2,092** | **3,690,230** | **3.53** |

f) Please refer to Exhibit 4, Tab 1, Schedule 1, page 109 Table 5.2.3-6 for the SAIDI target during the DSP term. Please refer to Exhibit 4, Tab 1, Schedule 1, page 111 Table 5.2.3-8 for the SAIFI target during the DSP term. Alectra Utilities does not have a MAIFI target during the DSP term.

g) Alectra Utilities' decision to maintain reliability to the overall system level is based on the findings from its Customer Engagement that despite price concerns, customers are generally willing to consider paying more to maintain a reliable system. Refer to Exhibit 4, Tab 1, Schedule 1, Page 35 for a detailed explanation of the methodology and outcomes from the placemat consultation. Alectra Utilities, based on customer preferences, is proposing to maintain reliability at a system level.

**EP-5**

**Reference.: Exhibit 2, Tab 1, Schedule 2, Page 11**

**Preamble: "Details on the customer engagement process are set out in Sections 5.2.1, 5.3.1 and 5.4.1 of the DSP, and the impact that customer input had on specific investment categories is described in the respective capital narratives provided as appendices to Section 5.4.3 of the DSP."**

**Question:**
**What information was provided in the customer survey regarding system reliability relative to the other Ontario utilities? Please provide a copy of the specific data/information for each class surveyed.**

**Response:**

Based on customer feedback from previous years and the first round of customer engagement completed to understand customer needs and priorities, Alectra Utilities determined that the most effective manner to present investment options to attain customer preferences was to present reliability information using historical trends so that the customer could relate to their own experience and not those of other utilities' customers.

As Alectra Utilities explained in detail in Section 5.2.1.5 Customer Engagement, a two phase process was used to develop an in-depth understanding of Alectra Utilities' customers' needs, priorities and preferences and integrate them into the company's 2020-2024 Distribution System Plan. Since 2017, Alectra Utilities has engaged with its customers on capital planning-related issues at least once per year. The utility's customers have consistently said that they want the utility to maintain a reliable distribution system, even if that means some increase in their distribution rates. Alectra Utilities was also constrained in the length of the customer engagement questions as feedback from focus groups in testing indicated concerns for the length and amount of detail provided to customers. In the second round of engagement, customers were asked to provide feedback on the engagements, and 80% of residential customers responded by stating that the engagement had just the right information. The response from 76% of small business customers, 126 of 158 (80%) of General Service customers and 16 of 18 (89%) of large users also informed Alectra Utilities that the amount of information provided to customers in the customer engagement was just the right amount.

Alectra Utilities provided all customers with information on system reliability trends as well as information on outages due to defective equipment and rear lot services. The information presented to customers is provided in Appendix C of the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix C, Pages 33, 40, 49, 98, 105, 114, 148, 155, 163, 196, 203, 221)

**EP-7**

**Reference: EB-2014-0219 Decision, Page 13, Section 4.1.1, The Adoption of the "Discrete" Project Criterion**

**Preamble: "The Board is of the view that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs. This would apply to both ACMs and ICMs going forward."**

**Question:**

**a) Assuming that Alectra could implement the DSP under the ACM policy, please discuss which elements of the 2020-2024 DSP meet the noted criterion from the ACM/ICM Report as opposed to "not part of typical annual programs."**

**b) Please list the specific projects that qualify under the "discrete projects" criterion.**

**Response:**

a) The ACM is available for investments identified as part of a cost of service application. As Alectra Utilities has not filed a cost of service rebasing application, the investments identified in its DSP are not eligible for ACM.

Regarding ICM, Alectra Utilities identifies that the statement of the OEB's views with respect to eligibility for incremental capital funding, as quoted in the preamble, was superseded by statements of the OEB's views with respect to eligibility for incremental capital funding specifically in the context of distributor consolidations. In particular, the referenced quote suggesting the ineligibility of "typical annual capital programs" is from the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued in EB-2014-0219 on September 18, 2014 (the "ACM Report"). However, in the *Report of the Board – Rate Making Associated with Distributor Consolidation*, issued in EB-2104-0138 on March 26, 2015 (the "MAADs Report"), the OEB states its view 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.[1]" Moreover, in the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations*, issued on January 21, 2016 (the "MAADs Handbook"), the OEB reiterates that, in the context of consolidating distributors, "[t]he 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." In this context, all of the projects that Alectra Utilities has identified in the DSP that are M-factor eligible would also qualify for ICM treatment.

b) Please see Alectra Utilities' response to SEC-25.

[1] The MAADs Report, p.9

**EP-8**

**Reference: Exhibit 2, Tab 1, Schedule 3, Page 4, and Exhibit 4, Tab 1, Schedule 1, page 6**

**Question:**

**a) Please confirm that XLPE cable is not unique to Alectra and that a number of other utilities also have it.**

**b) Please file a repair vs replace discounted cash flow analysis of XLPE cable, listing all assumptions. If such an analysis does not exist, please explain why not.**

**c) Why is there a large reduction in "good condition" cable length in year 25?**

**d) Why does the cable suddenly become "poor" in year 32 and "very poor" in year 36?**

**e) How many kilometers of XLPE cable has Alectra and each of its predecessor utilities replaced each year for the past 5 years? Please provide the length for each utility, the cost per year and the cost per kilometer.**

**f) Please provide the cost for each of the next 5 years that Alectra proposes to spend on XLPE cable replacement and the length in km per year that Alectra proposes to replace.**

**Response:**

a) Alectra Utilities has identified that deterioration of underground cable, specifically XLPE cable, is not a unique challenge limited to Alectra Utilities. As reported by Vanry & Associates ("Vanry") in the DSP Assurance Review Report (Appendix G of the DSP), Vanry states: *"Alectra like many utilities in North America, is battling a chronic failure of Underground Residential Distribution ("URD") cable, referred to by Alectra in its DSP documentation as XLPE."*

b) As explained in Section 5.3.3.2 of the DSP (Exhibit 4, Tab 1, Schedule 1, pages 262 to page 265), Alectra Utilities' replacement strategy for underground conductors and accessories for Cross-linked polyethylene (XLPE) cable has two implementation paths; cable rehabilitation and cable replacement. It is important for Alectra Utilities to clarify that in normal course of operation, Alectra Utilities will repair failed cable by splicing out the faulted segment. So in this manner, Alectra Utilities already applies the repair approach up to a point where a cable is a candidate for rehabilitation based on eligibility. Should Alectra Utilities identify that cable with a history of failure (i.e., faulty and already repaired) and condition deteriorated beyond a point where rehabilitation is possible, the only course of renewal available is cable replacement. It is based on this approach that Alectra Utilities has developed the planned cable replacement strategy. Alectra Utilities has experienced underground cable failures and tried to repair them until a planned replacement project can be implemented only to have the cable continue to fail and no longer be reliable for service. Alectra Utilities has not completed a replace versus repair analysis for cable replacement as the company does not run cable to failure. Alternatively, Alectra Utilities did analyze a reduced cable replacement option, as presented on page 21 of Appendix A10 of the DSP.

c) In reference to Exhibit 2, Tab 1, Schedule 3, Page 4, Figure 5, the graph illustrates the quantities of cable installed by age. The amount of cable installed in any given year is driven by a multitude of factors including, but not limited to, system expansion and customer connections. The reference to the year 25 decline in cable in “good” condition is related to the installations made in 1993. Due to the economic recession of early 1990s, Alectra Utilities’ predecessors experienced a slower rate of system expansion, as the need to connect customers during that period declined.

d) Alectra Utilities wishes to clarify that most of the cables with ages 32 and 33 are in the “Fair” category, ages 34 to 36 in the “Poor” category, and ages greater than 36 in the “Very Poor” category. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 17 for a detailed explanation of the methodology used by Alectra Utilities to derive the Health Index of underground cables.

e) Alectra Utilities has provided the amount of cable replaced (not injected), total cable replacement cost, and the cost per kilometer per year in Table 1. However, Alectra Utilities cautions that due to variation in the historical capital tracking and reporting practices of legacy utilities, these costs were not accounted for on the same basis. For example, the cost in Alectra Utilities’’ predecessor, Horizon Utilities, is just the cable costs and does not include the duct work; it may also include PILC cable costs. In Alectra Utilities’ predecessor

Enersource, values were taken from subdivision rebuilds which include transformer costs and switchgear costs.

**Table 1: Cost ($MM) and Quantity (kms) of Cable Replacement by Area per Year Between 2015-2018**

| Area | | Year 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| BRZ | Cost ($MM) | $2.657 | $0.634 | $4.251 | $4.001 |
| | Quantity (km) | 1.97 | 0.5 | 5.09 | 7 |
| | Unit Cost ($MM/km) | $1.349 | $1.268 | $0.835 | $0.572 |
| PRZ | Cost ($MM) | $12.105 | $9.790 | $8.341 | $9.865 |
| | Quantity (km) | 33.3 | 29.6 | 20.5 | 22.3 |
| | Unit Cost ($MM/km) | $0.364 | $0.331 | $0.407 | $0.442 |
| ERZ | Cost ($MM) | $14.977 | $13.434 | $18.670 | $16.125 |
| | Quantity (km) | 21.69 | 16.75 | 19.12 | 33.64 |
| | Unit Cost ($MM/km) | $0.691 | $0.802 | $0.976 | $0.479 |
| HRZ | Cost ($MM) | $0.000 | $2.886 | $6.610 | $2.486 |
| | Quantity (km) | 0 | 17.28 | 14.5 | 10.57 |
| | Unit Cost ($MM/km) | $0.000 | $0.167 | $0.456 | $0.235 |
| GRZ | Cost ($MM) | $0.502 | $2.030 | $1.548 | $0.256 |
| | Quantity (km) | 1.49 | 5.27 | 6.6 | 0.43 |
| | Unit Cost ($MM/km) | $0.337 | $0.385 | $0.235 | $0.595 |
| Alectra Utilities | Cost ($MM) | $30.241 | $28.773 | $39.419 | $32.733 |
| | Quantity (km) | 58.45 | 69.40 | 65.81 | 73.94 |
| | Unit Cost ($MM/km) | $0.517 | $0.415 | $0.599 | $0.443 |

f) Alectra Utilities proposes to replace 675.38km at a total cost of $236.33MM over 2020-2024 time period. Alectra Utilities provides the details by year in Table 2.

**Table 2: Cost ($MM) and Quantity (kms)**

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Cable Length (kms) | 93.00 | 130.00 | 139.75 | 150.23 | 162.40 |
| Cost | $ 32.67 | $ 44.20 | $ 49.21 | $ 52.71 | $ 57.54 |

**EP-9**

**References: EB-2014-0219 Decision, Page 18, Section 4.2; Exhibit 2, Tab 1, Schedule 4, Page 4, Table 17; Exhibit 04, Tab 01, Schedule 01, Appendix A03 - Road Authority and Transit Projects; Exhibit 4, Appendix B, Material Investment Business Cases, page 10, Road Authority Projects**

**Preamble: "Distributors must also include a discussion on any offsets associated with each incremental project for which ACM or ICM treatment is proposed due to revenue to be generated through other means (e.g. customer contributions in aid of construction), at the time of the cost of service application, along with an estimate of the revenue requirement impact associated with those offsets."**

**Question:**

a) **Please provide a list of qualified projects from the DSP and show for each rate zone, date in service, gross capital and net capital with estimated offset contributions, such as CIAC.**

b) **List by rate zone, the Transit Projects and other Municipal Projects that require deferral or changes to the DSP. Please discuss management of the impacts of these projects.**

c) **Please explain in detail how the revenue requirement impacts associated with the externally driven projects flow through the "EDCVA" to the rate riders?**

d) **Please list each YRRT relocation project with the amount spent to date and the forecast amount.**

e) **In the EB-2018-0016 proceeding Alectra stated that it considers York Region Rapid Transit a Road Authority under the Public Service Works in Highways act and that as a result YRRT is only paying approximately 50% of Alectra's relocation costs for YRRT projects. During the EB-2018-0165 Proceeding Toronto Hydro stated that Toronto Hydro does not consider Metrolinx to be a Road Authority under the act and that as a result, Metrolinx is paying 100% of Toronto Hydro's relocation costs for the Eglinton Crosstown project. Has Alectra requested YRRT to pay 100% of relocation costs? If not, why not?**

**Response**

a) Table 1, below provides a list of Road Authority projects, with the Net Capital Expenditure, Contributions, Gross Capital Expenditure and In-service year.

**Table 1 – List of Qualified Road Authority Projects in the DSP ($MMs)**

| ($MM) Project Description | Rate Zone | 2020 Net / Contribution / Gross | | | 2021 Net / Contribution / Gross | | | 2022 Net / Contribution / Gross | | | 2023 Net / Contribution / Gross | | | 2024 Net / Contribution / Gross | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dixie Rd. - Countryside to Bovaird | BRZ | 1.2 | 0.6 | 1.8 | | | | | | | | | | | | |
| Williams Pkwy. - Kennedy to North Park | BRZ | 1.7 | 0.8 | 2.5 | | | | | | | | | | | | |
| Goreway Dr. - Countryside to Castlemore | BRZ | 1.2 | 0.6 | 1.8 | | | | | | | | | | | | |
| Square One Dr. Extension Confederation to Rathburn | ERZ | 1.4 | 0.6 | 2.0 | | | | | | | | | | | | |
| QEW Evans/Cawthra – Phase 1 | ERZ | 2.0 | 1.0 | 3.0 | | | | | | | | | | | | |
| Anne St Bridge | PRZ | 1.1 | 0.5 | 1.6 | | | | | | | | | | | | |
| Rutherford Rd - Jane to Westburne | PRZ | 2.0 | 1.0 | 3.0 | | | | | | | | | | | | |
| Keele Street – Steels to Snidercroft Phase 2 | PRZ | 1.4 | 0.6 | 2.0 | | | | | | | | | | | | |
| Mississauga Rd. - Queen to Financial | BRZ | | | | 1.1 | 0.5 | 1.6 | | | | | | | | | |
| Goreway Dr. - Castlemore to Humberwest | BRZ | | | | 4.0 | 2.0 | 6.0 | | | | | | | | | |
| Torbram Rd. - Queen to City Limit – Phase 1 | BRZ | | | | 1.7 | 0.8 | 2.5 | | | | | | | | | |
| QEW Evans/Cawthra – Phase 1 | ERZ | | | | 2.0 | 1.0 | 3.0 | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Duckworth Street (Bell Farm to St.Vincent) | PRZ | | | | 1.4 | 0.6 | 2.0 | | | | | | | | | |
| Rutherford Rd - Bathurst to Peter Rupert | PRZ | | | | 1.6 | 0.7 | 2.3 | | | | | | | | | |
| Teston Rd - PVD to Teston | PRZ | | | | 1.4 | 0.6 | 2.0 | | | | | | | | | |
| Highway 5/6 Interchange (Hamilton) | HRZ | | | | 2.0 | 1.0 | 3.0 | | | | | | | | | |
| Mayfield Rd. - Hurontario to Heart Lake Rd. | BRZ | | | | | | | 1.1 | 0.5 | 1.6 | | | | | | |
| Sandalwood Pkwy. - Torbram to Airport | BRZ | | | | | | | 1.6 | 0.8 | 2.4 | | | | | | |
| Torbram Rd. - Queen to City Limit – Phase 2 | BRZ | | | | | | | 1.7 | 0.8 | 2.5 | | | | | | |
| Mapleview Drive Grade Separation at Yonge | PRZ | | | | | | | 1.7 | 0.8 | 2.5 | | | | | | |
| Garden City Skyway - Bridge Replacement | HRZ | | | | | | | 3.0 | 1.5 | 4.5 | | | | | | |
| Mississauga Rd. - Bovaird to Queen | BRZ | | | | | | | | | | 1.5 | 0.8 | 2.3 | | | |
| Sandalwood Pkwy. - Bramalea to Torbram | BRZ | | | | | | | | | | 1.5 | 0.7 | 2.2 | | | |
| Torbram Rd. - Bovaird to Queen | BRZ | | | | | | | | | | 1.7 | 0.8 | 2.5 | | | |
| Sandalwood Pkwy. - Dixie to Bramalea | BRZ | | | | | | | | | | | | | 1.3 | 0.6 | 1.9 |
| Williams Pkwy. - North Park to Torbram | BRZ | | | | | | | | | | | | | 3.5 | 1.7 | 5.2 |

b) As of August 2018, there are no known transit or municipal projects that would result in deferral or changes to the DSP. For managing changes and deferral of projects, Alectra Utilities has proposed, as referenced in Appendix A-03, Road Authority and Transit Projects, the creation of an Externally Driven Capital Variance Account ("EDCVA") which would capture the difference between the revenue requirement in rates associated with externally-driven capital expenditures related to Road Authority projects and Transit projects. The EDCVA would mitigate the inherent uncertainty of third-party requirements.

c) Alectra Utilities has forecast capital expenditures of approximately $20MM per year (net of contributions) for externally driven capital related work. The expenditures were excluded from the list of M-factor capital projects. Therefore, if Alectra Utilities incurs capital in excess of $20MM, Alectra Utilities will calculate the revenue requirement associated with the additional investment.

d) Table 2 provides the inception to date costs of each YRRTC relocation project and the forecasted costs as of Q2 2019.

**Table 2 - June 2019 Inception To Date (ITD) spend for YRRTC and Q2 Forecasted ITD spend**

| Sections | June 2019 ITD Gross CAPEX | June 2019 ITD Contributed Capital | June 2019 ITD NET CAPEX | Forecasted ITD Gross CAPEX | Forecasted ITD Contributed Capital | Forecasted ITD NET CAPEX |
|---|---|---|---|---|---|---|
| H2 EAST | 11,450 | (5,900) | 5,550 | 11,450 | (5,900) | 5,550 |
| H2 WEST | 18,828 | (10,158) | 8,670 | 18,828 | (10,158) | 8,670 |
| Y2.1 | 39,851 | (19,736) | 20,115 | 40,071 | (20,952) | 19,119 |
| Y2.2 | 13,326 | (7,123) | 6,203 | 13,326 | (7,123) | 6,203 |
| | | | | | | |
| **Total** | **83,455** | **(42,917)** | **40,538** | **83,675** | **(44,133)** | **39,542** |

e) Alectra Utilities has no knowledge of the Toronto Hydro work related to the Eglington Crosstown project and cannot comment as to the treatment of the Public Service Works on Highways Act ("PSWHA") related to that work.

Reviewing publically available documentation by Metrolinx on the Eglinton Crosstown project available on the Metrolinx website[1], Alectra Utilities has determined that the project is a Light Rail Transit initiative which requires constructing of train rails that facilitate light train transit. Alectra Utilities does not apply the treatment of the Public Service Works on Highways Act (PSWHA) to train rail initiatives and would not consider agencies that construct, operate and maintain train rails as road authorities under the PSWHA.

The York Regional Rapid Transit project, as described by Alectra Utilities in both EB-2018-0016 (2019 EDR Application, Exhibit 1, Tab 1, Schedule 1, Page 8, Line 9) and EB-2017-0024 (2018 EDR Application, Exhibit 2, Tab 3, Schedule 10, Page 6, Lines 10 to 15), is a Bus Rapid Transit ("BRT") project to facilitate expedited bus travel on existing roads. Since buses operate on roads and York Regional Municipality is recognized as the governing entity with jurisdiction of the boulevards of the roads on which the BRT will operate, Alectra Utilities recognizes York Regional Municipality and its wholly-owned subsidiary, York Region Rapid Transit Corporation, as a road authority under the PSWHA.

[1] http://www.thecrosstown.ca/

**EP-11**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 3**

**Question:**

a) **Please provide numerical evidence to support the claim that Alectra has experienced declining levels of reliability.**

b) **Please provide a table of causes of reliability decline with numerical impact of each cause.**

**Response:**

a) Please see Tables 5.2.3-6 and 5.2.3.-7 in the Section 5.2.3 of the DSP (Exhibit 4, Tab 1, Schedule 1) for numerical evidence indicating that reliability is declining. Further, in Exhibit 4, Tab 1, Schedule 1, Section 5.2.3 Performance Measurement and Continuous Improvement, page 108 line 11 and line 13, provides additional numerical evidence that over a five year period SAIDI has increased (worsening reliability). Similarly, in Exhibit 4, Tab 1, Schedule 1, Section 5.2.3 Performance Measurement and Continuous Improvement page 110 line 8 and line 10, Alectra Utilities provides additional numerical evidence that over a five-year period, SAIFI has increased (worsening reliability).

b) Alectra Utilities has provided, in Table 1 below, the reliability cause codes with declining reliability and the numerical impact on SAIDI each year (2014-2018). As provided in Exhibit 2, Tab 1, Schedule 2, Page 3, Alectra Utilities' investment priorities for underground cable and the overhead system are planned to address the negative trend of worsening reliability due to Defective Equipment and Adverse Weather, which have the greatest impact on SAIDI.

**Table 1 - Declining Reliability Cause Codes by SAIDI (min) from 2014-2018**

| Outage Cause Code (min) | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| Tree Contacts | 4.19 | 5.85 | 6.49 | 4.91 | 7.82 |
| Defective Equipment | 27.42 | 26.60 | 26.74 | 22.46 | 30.46 |
| Adverse Weather | 11.91 | 6.87 | 21.20 | 14.21 | 42.56 |

**EP-12**

**References: EB-2014-0219 Decision, Page 24, Section 7.1.5 Rate Riders; Exhibit 2, Tab 1, Schedule 3, Page 17; Exhibit 5, Attachment 3**

**Preamble:**
**"Distributors must file the calculation supporting the proposed rate riders to recover the incremental revenue from each applicable customer class, and the rationale for the proposed approach."**

**Question:**

**a) Please provide expanded explanations for the Rate Zone Allocation Methodology.**

**b) Please confirm that for each Rate Zone, the Capex under the Tab "Summary by RZ" is based on the DSP.**

**c) Based on the Tab showing the RZ Capex please provide the ISAs for each rate zone.**

**d) Please explain in detail what assets are included in "Multiple" e.g. Is this Back Office Capital, IT etc.?**

**e) What is the basis of the allocation factors for "Multiple" to each Rate Zone? List the allocation factors such as revenue, rate base etc. and the weightings for each.**

**f) Please show how "Multiple" is allocated to the rate classes in each RZ.**

**Response:**

a) The proposed M-factor capital projects were based on the projects identified in each rate zone. For projects that span all rate zones (e.g. IT projects), Alectra Utilities allocated the costs of these projects to each rate zone based on each rate zone's proportion of Alectra Utilities' consolidated rate base. The detailed calculation is provided in Tab 'Weighted Averages' of the M-factor Revenue Requirement Model filed in response to G-Staff-8.

b) Alectra Utilities confirms that the M-factor capital expenditures identified in Tab 'Summary by RZ' is based on the DSP.

c) The data provided in Tab “Summary by RZ” is provided by year, which represents the expected in-service year for the proposed M-factor projects.

d) Please see response to part a).

e) Please see response to part a).

f) The allocation of multiple by RZ is provided in Tab ‘Summary by RZ’.

**EP-13**

**References: Exhibit 2, Tab 1, Schedule 4, Page 7; EB-2014-0219 Decision, Page 25, Section 7.3**

**Preamble: "The EDCVA would operate symmetrically, such that the revenue requirement associated with any prudent expenditures in excess of the level reflected in rates would be recoverable by the Applicant, and any excess funding in rates would be refundable to customers in a future proceeding. Carrying charges would apply to the opening balances in the account at the OEB-approved rate."**

**Question:**

**a) Does Alectra expect to add/delete projects or change project timing/pacing from the approved DSP during the Rebasing Period? If so what mechanism is there to review such changes?**

**b) How frequently will the EDCVA balances be reviewed and disposed of?**

**Response:**

a) As provided in Exhibit 2, Tab 1, Schedule 4, the DSP includes forecasts for the capital costs associated with confirmed road authority and transit projects. The proposed EDCVA is intended to capture differences between those forecasts and Alectra Utilities' actual capital costs for such relocation and reconstruction work, including for changes to the scope or timing of anticipated road authority and transit projects and for additional road authority and transit projects not currently contemplated. Please also see Alectra Utilities' response to EP-9.

b) The proposed effective date for the variance account is January 1, 2020, the start of the five year Distribution System Plan ("DSP") period. As identified in Exhibit 2, Tab 1, Schedule 4, p.6, Alectra Utilities anticipates reviewing and disposing of EDCVA balances every five years.

**EP-14**

**References: Exhibit 2, Tab 1, Schedule 4, Page 7; EB-2014-0219 Decision, Page 25, Section 7.3**

**Preamble: "The EDCVA would operate symmetrically, such that the revenue requirement associated with any prudent expenditures in excess of the level reflected in rates would be recoverable by the Applicant, and any excess funding in rates would be refundable to customers in a future proceeding. Carrying charges would apply to the opening balances in the account at the OEB-approved rate."**

**Question:**

a) **Does Alectra expect to add/delete projects or change project timing/pacing from the approved DSP during the Rebasing Period? If so what mechanism is there to review such changes?**

b) **How frequently will the EDCVA balances be reviewed and disposed of?**

**Response:**

This is a duplicate question of EP-13.

**EP-19**

**Reference: Exhibit 04, Tab 01, Schedule 01, 5.2.3 Performance Measurement for Continuous Improvement, page 100**

**Preamble: Table 5.2.3 - 2(A): Finance: Cost Control Custom Performance Measure indicates that Historical (2018) performance was 84% and the 2020 – 2024 Target is 100%.**

**Question:**

**a) Please provide the calculation that supports the 84% performance measure.**

**b) Please explain the 100% target. Would a target be achieved if 100% of the budget was spent for a particular project but the project did not deliver the expected benefits in reliability improvement?**

**Response:**

a) Refer to Table 1 and the supporting equation, which provides the calculation of the 84% performance measure for 2018.

**Table 1 - Cost Control Performance Measure Calculation**

| ($MM) | 2018 Actual | 2018 Budget | Variance |
|---|---|---|---|
| System Renewal | 120.2 | 129.3 | (9.1) |
| System Service | 24.1 | 32.3 | (8.2) |
| Less: Reactive | (20.1) | (14.1) | 6.0 |
| **Total Planned Capital** | **124.2** | **147.5** | **(23.3)** |

**Equation - Cost Control Performance Measure Calculation for 2018**

$$\boldsymbol{Cost\ Control\ Performance\ Measure} = \frac{\mathbf{2018}\ \boldsymbol{Actual}}{\mathbf{2018}\ \boldsymbol{Budget}}$$

$$\boldsymbol{Cost\ Control\ Performance\ Measure} = \frac{\$\mathbf{124.2}\boldsymbol{MM}}{\$\mathbf{147.5}\boldsymbol{MM}}$$

$$\boldsymbol{Cost\ Control\ Performance\ Measure} = \mathbf{84}\%$$

b) The Cost Control Performance Measure (A) provides the % of Planned Capital Projects Actual Costs compared to Budget, the measure has a second component (B) which provides the % of Planned Capital Projects Completed projects which provides the number of Planned Capital Projects completed relative to the total number of Planned Capital Projects approved for that year. A 100% achievement in part A reflects that the total expenditures of Planned Capital projects for that year matches the budget for Planned Capital Budgets. Combined with a 100% score in part B, the measure would reflect that all Planned Capital projects were completed on budget and in the year planned.

**EP-20**

**Reference: Exhibit 04, Tab 01, Schedule 01, 5.2.3 Performance Measurement for Continuous Improvement, page 101**

**Preamble: "Since Alectra Utilities' Planned Capital Project Completed measure was developed in 2019, there are no historical measures available. Alectra Utilities will measure and track its Planned Capital Projects Completed levels using the performance measure over the duration of the DSP implementation period to establish a baseline from which it may in future propose a target." The quoted statement seems to indicate that Alectra expects that it will not complete many capital projects.**

**Question:**
**Why should the OEB be satisfied with poor project completion performance by Alectra?**

**Response:**

Planned Capital projects includes System Renewal (with the exception with Reactive Capital) and System Service investments. Alectra Utilities developed the Cost Control Measure (Part A and Part B) that together, measure the performance of all planned capital project completion and to budget. There are numerous situations where Alectra Utilities may be required to adjust and modify planned capital work, especially for unforeseen investments such as system access or reactive capital to stay prudently within the approved capital funding envelope. As such, Alectra Utilities monitors the implementation of the DSP projects based on approved funding in order to develop a baseline to establish a meaningful and prudent target.

**EP-21**

**Reference: Exhibit 04, Tab 01, Schedule 01, 5.2.3 Performance Measurement for Continuous Improvement, pages 122 and 123**

**Preamble: "The CPI and SPI are new measures introduced after the formation of Alectra Utilities. Therefore, the requisite five years of historical data are not available. Alectra Utilities will measure and track its work execution DSP-specific performance measure over the duration of the DSP implementation period to establish a baseline from which it may in future propose a target."**

**Question:**

a) **Please provide numerical examples of how the Cost Performance Index (CPI) and the Schedule Performance Index (SPI) are calculated.**

b) **Did Alectra or its legacy distributors track cost and schedule performance of its capital projects? If the answer is yes, for each legacy distributor please provide data on cost and schedule performance of capital projects. If the answer is no, please explain why.**

c) **Should the OEB impose a target for Alectra that all projects be completed on budget and on schedule? Please explain your answer.**

**Response:**

a) The Cost Performance Index ("CPI") is measured for each project and provides the ratio of actual cost to budget costs. Whereas, the Cost Control – Planned Capital (Parts A and B) DSP Performance Measure tracks the overall Planned Capital portfolio, the CPI measures each project's completion so that Alectra Utilities can measure and analyze reasons for individual project variances. As an example, if Project A with a budget of $500k is completed with an actual cost of $475k, the CPI is measured as the ratio of actual expenditure to budget for Project A would be 0.95 or 95%.

The Schedule Performance Index ("SPI") is measured for each project and provides a comparator of actual completion date to the planned completion date. Whereas, the Cost Control – Planned Capital (Parts A and B) DSP Performance Measure tracks the overall Planned Capital portfolio, the SPI measures each project's completion so that Alectra Utilities can measure and analyze reasons for individual project schedule variances. As an example, if Project B has a scheduled completion date of May 1, and an actual completion date of April 15, the SPI for this project is 1 as the completion date was met. Further, if Project C has a scheduled completion date of June 30, and an actual completion date of July 15, the SPI for this project is 0 as the completion date was not met.

Alectra Utilities plans to track each project's costs and scheduled completion against budget and plan in order to better understand the project planning and execution.

b) Predecessor utilities at Alectra Utilities tracked and reported capital project completion and costs in different measures befitting historical work practices and procedures. CPI and SPI were only calculated in this manner by Legacy Horizon. The other predecessor utilities tracked project costs at a either business unit or other project grouping levels as required by legacy work practices. With the implementation of Alectra Utilities ERP system in July 2019, Alectra Utilities proposes to gather costs and completion dates in a uniform and consistent manner so that CPI and SPI will be calculated and reported across all capital work projects.

c) Alectra Utilities cannot speculate on whether the OEB should impose a target relating to the funding and performance measurement criteria of the DSP, including performance targets.

**EP-22**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 3, York Hill/ Hilda cable replacement project**

**Question:**

a) **What is the budget of the York Hill/ Hilda cable replacement project and how much has been spent to date?**

b) **When did the project start?**

c) **What is the cost per metre of the replacement project?**

d) **Please provide discounted cash flow repair vs replace analysis of the York Hill/ Hilda cable replacement project.**

**Response:**

a) Alectra Utilities did not budget the cable replacement for the York Hill / Hilda area, as the renewal was completed on an emergency basis which required Alectra Utilities to reallocate urgently needed capital to address the failed cable in the area. Since October 2017, Alectra Utilities has tried to repair cable failure using splices as is standard practice. The increasing number of failures peaked during July 2018, at which point Alectra Utilities determined that the cable was no longer a candidate for repair and required emergency replacement. From October 2017 to July 2018, Alectra Utilities incurred $208K in operating and maintenance costs required to investigate, excavate and repair cable failures using splices. The high number of outages frustrated and angered the residents in the area. Alectra Utilities received significant negative and angry responses from customers that were impacted by the frequent and repeated outages. Customers also indicated concern about the amount of excavation required in order to access the underground cables. Please see Figure A10 in Appendix A10 for an illustrative representation of the excavation required to access the failed cable. Once Alectra Utilities realized that the cable was no longer a candidate for repair, Alectra Utilities incurred $3.8MM in emergency capital costs to replace the deteriorated cable. The customers in the area experienced a total of 40 sustained outages from 2017 to 2018, peaking with eight outages over a three week period in the summer of 2018.

b) Once Alectra Utilities determined that the cable needed to be replaced under an emergency project, the capital work started in July 2018. Cable repairs, which were tracked as operating and maintenance costs, started in October 2017.

c) Once Alectra Utilities determined that the only feasible solution was to replace the cable under an emergency capital project, cost per meter for the York Hill/Hilda cable replacement project was $267. Alectra Utilities managed to contain the cost of the emergency replacement since several segments of the underground system was already excavated for earlier repairs.

d) Alectra Utilities did not complete a discounted cash flow repair versus replace analysis of the York Hill / Hilda cable replacement project. As described in response to a), prior to initiating the emergency cable replacement project, Alectra Utilities had attempted repair the cable on numerous occasions. Unfortunately, repair proved unsuccessful as faults continued to increase in 2018 until such a point where the cable was no longer dependable, failing shortly after repair.

**EP-23**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 5**

**Question:**

**a) Please explain what Alectra means when it refers to "secure funding" and how it differs from a series of blank cheques.**

**b) Is Alectra claiming that the OEB's 4GIRM does not allow for "secure funding" of capital projects.**

**Response:**

a) Alectra Utilities' request to secure funding is in reference to its request for approval of incremental capital funding over a 5-year term based on a rate-adjustment mechanism, referred to as the "M-factor", that reconciles the capital needs set out in its 2020-2024 Distribution System Plan ("DSP") with the capital-related revenue in rates, and associated 2020 to 2024 capital riders for each rate zone ("RZ").
Alectra Utilities is not otherwise prepared to respond to the rhetorical component of this interrogatory.

b) Capital funding within the 4th Generation IRM ("4GIRM") is available through the Incremental Capital Module ("ICM"). ICM provides a single year's worth of capital funding based on capital funding needs. It does not provide the flexibility that Alectra Utilities requires over the five-year DSP term, nor does it provide multi-year or longer-term availability of funding needed to execute a DSP. Please see Alectra Utilities' response to G-Staff-16.

**EP-24**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 8**

**Question:**

**a) When did Downtown Mississauga start intensifying?**

**b) Is Alectra claiming that it needs "secure funding" to connect 6 buildings?**

**c) If the answer to (b) is yes, please provide a numerical analysis to support the claim that demonstrates that rates paid by the owners or occupants of the 6 buildings are inadequate to fund the connection.**

**Response:**

a) Major intensification started to occur in 2006 with the Provincial approved of the Places to Grow Act: the Growth Plan for the Greater Golden Horseshoe, which established the boundaries for urban growth and established Mississauga and City Centre as Urban Growth Centre with a target of 200 residents and/or jobs per hectare by 2031. The City center started to see major high-density residential development starting in 2010 and now has the second highest number of high density development in GTA.

b) Alectra Utilities has not claimed that it needs to secure funding to connect 6 buildings, rather, the six buildings referred to are an example of the rapid development and intensification occurring which requires Alectra Utilities to invest in its distribution system which includes feeders and stations necessary to support the downtown development needs as well as existing customers in that area. These investments enable Alectra Utilities to fulfill its obligations as a licensed distributor and provide normal and contingency supply in the growing areas and ensure reliability to existing customer in these areas of intensification.

c) Please see response to part b).

**EP-25**

**References: Exhibit 04, Tab 01, Schedule 01, Pages 11 and 12**

**Question:**

**a) Are Alectra's annual capital needs far greater than the combined capital needs of the legacy utilities prior to the 2017 amalgamation? If the answer is yes, please**

**b) Please provide a numerical analysis that demonstrates that Alectra's revenues together with productivity savings from amalgamation are insufficient to fund capital needs.**

**c) Considering that amalgamation was approved less than two years ago, why has Alectra given up so soon on finding productivity and efficiency savings that could be used as a source of funds for capital projects?**

**Response:**

a) No, Alectra Utilities' annual capital needs are consistent with the combined needs of the legacy utilities. Please see Alectra Utilities' response to Staff-11 b) and c). Alectra Utilities identifies that the ability to plan and prioritize capital needs on a consolidated basis across all of its service area allows for the more efficient deployment of capital. It has provided opportunities to avoid investments that would otherwise have been needed if investment planning was performed on an individual utility basis. For example, please see Exhibit 4, Tab 1, Schedule 1, Section 5.4.3, Section C.2.5, pp. 388.

b) and c) Please see Alectra Utilities' response to G-Staff-15(b).

**EP-26**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 13**

**Preamble: "Should Alectra Utilities not receive sufficient funds to implement the renewal as proposed in this DSP, Alectra Utilities will have to defer essential system renewal investments which are projected to have a significant negative impact on reliability." Alectra's message to the OEB appears to be a classic shakedown threat: give us the money or reliability gets it.**

**Question:**

**a) Why does Alectra believe that the OEB would respond favourably to a shakedown threat?**

**b) Please provide a numerical analysis that supports the claim that reliability would decrease by 50% over the next 5 years and by a further 112% over the next 10 years.**

**c) Please provide a 10 year projection of SAIDI, SAIFI and MAIFI under each scenario.**

**Response:**

a) Alectra Utilities has planned system renewal investments with the benefit of improving reliability in the worst performing areas and reversing the negative trend in reliability experienced over the last five years. The scenario presented in Exhibit 4, Tab 1, Schedule 1, Page 13 Lines 3-5, conveys Alectra Utilities' projections of the outcomes in each scenario.

b) The reliability analysis is based on the system renewal investments outlined in Exhibit 4, Tab 1, Schedule 1, page 12, Figure 5.0 - 8. This long-term system renewal forecast provides the quantity of assets expected to fail per year as represented in Table 1. Alectra Utilities utilizes the defective equipment sub-cause data which provides a 5-year average failure impact for a variety of assets. A sample of the sub-cause data can be found in Exhibit 4, Tab 1, Schedule 1, Page 121, Figure 5.2.3-11 - a copy of this data is provided in Table 2. The impact of each failure is combined with the failure rate to derive an impact on SAIDI and SAIFI using 2018-year end reliability as a reference point. Assuming reliability and equipment failures follow the forecast in Figure 5.0-8, SAIDI would increase as provided in Table 3. The 50% and 112% is the difference between Alectra Utilities' 5-year average

SAIDI and the forecasted value from the analysis provided in Table 4. Alectra Utilities provides the calculation below:

**Equation 1 – Five Year Impact Calculation on Reliability Impact**

$$Five\ Year\ Impact = \left(\left(\frac{1.47}{0.98}\right) - 1\right) \times 100\%$$

$$Five\ Year\ Impact = 50\%$$

**Equation 2 – Ten Year Impact Calculation on Reliability Impact**

$$Ten\ Year\ Impact = \left(\left(\frac{2.08}{0.98}\right) - 1\right) \times 100\%$$

$$Ten\ Year\ Impact = 112\%$$

**Table 1 - Asset Failure Quantities – Long Term Planned Renewal Analysis**

| Year | UG Cable (XLPE) km | Switchgear (All types) | OH Switch (LIS only) | Distribution Transformer (All Types) |
|---|---|---|---|---|
| **2019** | 0 | 0 | 0 | 0 |
| **2020** | 87 | 4 | 12 | 115 |
| **2021** | 156 | 4 | 10 | 160 |
| **2022** | 183 | 4 | 8 | 195 |
| **2023** | 213 | 4 | 5 | 210 |
| **2024** | 230 | 4 | 4 | 220 |
| **2025** | 279 | 7 | 12 | 0 |
| **2026** | 322 | 5 | 17 | 0 |
| **2027** | 335 | 3 | 9 | 0 |
| **2028** | 314 | -3 | 0 | 0 |
| **2029** | 102 | -8 | -11 | 0 |
| **2030** | -29 | -8 | -21 | -8 |
| **2031** | -211 | -8 | -22 | -8 |
| **2032** | -293 | -4 | -22 | -8 |
| **2033** | -307 | 0 | -1 | 42 |
| **2034** | -311 | 0 | 0 | -358 |
| **2035** | -297 | 0 | 0 | -258 |
| **2036** | -288 | 0 | 0 | -258 |
| **2037** | -254 | 0 | 0 | -25 |

| | | | | |
|---|---|---|---|---|
| **2038** | -233 | 0 | 0 | -18 |

**Table 2 - 5 Year Average Reliability Asset Impact**

| 5 Year Reliability Average Impact | | | | | |
|---|---|---|---|---|---|
| Asset Type | # of Event | # of Customer Interruptions | Customer Hour Interruptions | Per Event Customer Impact | Per Event Duration Impact (hrs) |
| Cable & Accessories PILC | 14 | 14,633 | 23,966 | 1,031 | 1.64 |
| Cable & Accessories XLPE | 504 | 168,999 | 202,003 | 335 | 1.20 |
| Switches | 87 | 38,916 | 29,262 | 446 | 0.75 |
| Switchgear | 57 | 51,104 | 41,099 | 897 | 0.80 |
| OH Line Hardware | 157 | 87,219 | 85,845 | 557 | 0.98 |
| Transformer | 317 | 20,365 | 32,666 | 64 | 1.60 |

**Table 3: Alectra Utilities SAIDI copied from Table 5.2.3-5**

| Metric | 2014 | 2015 | 2016 | 2017 | 2018 | Average |
|---|---|---|---|---|---|---|
| SAIDI - Excluding MEDs | 0.88 | 1.05 | 0.96 | 0.87 | 1.14 | 0.98 |

**Table 4: Projected Reliability Impact**

| Year | SAIDI | |
|---|---|---|
| **2019** | **1.14** | |
| **2020** | **1.19** | |
| **2021** | **1.27** | |
| **2022** | **1.36** | |
| **2023** | **1.47** | 5 year |
| **2024** | **1.58** | |
| **2025** | **1.70** | |
| **2026** | **1.83** | |
| **2027** | **1.96** | |
| **2028** | **2.08** | 10 year |

c) Ten-year projections for SAIDI and SAIFI under the full funding and partial funding scenario are provided in Table 5. Alectra Utilities does not project MAIFI. The figures below provide the projections for SAIDI and SAIFI.

**Table 5: 10 Year Reliability Projection for SAIDI and SAIFI**

| Year | Requested Funding | | Partial Funding | |
|---|---|---|---|---|
| | SAIFI | SAIDI | SAIFI | SAIDI |
| 2019 | 1.53 | 1.14 | 1.53 | 1.14 |
| 2020 | 1.57 | 1.19 | 1.57 | 1.19 |
| 2021 | 1.64 | 1.27 | 1.64 | 1.28 |
| 2022 | 1.71 | 1.36 | 1.73 | 1.39 |
| 2023 | 1.80 | 1.47 | 1.84 | 1.52 |
| 2024 | 1.89 | 1.58 | 1.96 | 1.66 |
| 2025 | 1.99 | 1.70 | 2.12 | 1.85 |
| 2026 | 2.11 | 1.83 | 2.25 | 2.01 |
| 2027 | 2.22 | 1.96 | 2.38 | 2.16 |
| 2028 | 2.32 | 2.08 | 2.50 | 2.30 |

**EP-27**

**Reference: Exhibit 04, Tab 01, Schedule 01, Page 67, Figure 5.2.2-6**

**Question:**
**Please explain the reason for the sharp reduction in 2019 summer peak demand and the sharp increase in 2020 summer peak demand.**

**Response:**

Exhibit 4, Tab 1, Schedule 1, Page 67, Figure 5.2.2-6 represents the IESO's load forecast for Barrie TS which was included in the Barrie Innisfil Integrated Regional Resource Plan ("IRRP"). Alectra Utilities' 2019 capital plan includes completion of two new feeders from Midhurst TS which can be used to offload the load on Barrie TS. The IESO's load forecast reduction in the 2020 summer peak demand is based on Alectra Utilities' ability to transfer of up to 27 MW of load from Barrie TS to the two new feeders at Midhurst TS. Please refer to Appendix H02 – Page 42.

The increase in load from 2020 to 2033 is based on the load forecast provided by Alectra Utilities and Innisfil Hydro to the IESO during the IRRP.  Please refer to Appendix H02- Page 20 and 21.

**EP-28**

**Reference: Exhibit 04, Tab 01, Schedule 01, Appendix A07, Rear Lot Conversion, Page 15**

**Preamble: "Historical expenditures between 2015 and 2019 total $17.1 MM. There were no expenditures in 2018 as rear lot projects were dropped to due to mandatory work related to requests from road authorities. There are four projects which will be completed in 2019 at a cost of $5.1 MM."**

**Question:**

a) **Are rear lot conversion projects considered low priority projects that can be deferred due to lack of resources?**

b) **Please explain the reasons for the sharp reduction in planned capital expenditures on rear lot conversion in 2021 and 2022 and the large increase in 2024.**

c) **Please file a discounted cash flow repair vs replace analysis of the $19.9 million 2020-2024 capital expenditure on rear lot conversion projects.**

**Response:**

a) Alectra Utilities considers rear lot projects as necessary and required renewal investments that address functional obsolescence, reliability and safety needs. The outcomes of rear lot renewal projects include customer value, reliability, safety, environmental, and operating efficiency. A lack of available funding for capital investments in 2018 has required Alectra Utilities to defer rear lot renewal projects at the consequence of reliability and increased risk of failure. Alectra Utilities elected to defer the rear lot projects in order to seek input from those customers as per the OEB's findings in EB-2017-0024. As part of the DSP development, Alectra Utilities engaged in two rounds of customer engagement, in the second round Alectra Utilities received feedback from customers that reflected that customers supported the recommended pace as provided by Alectra Utilities.

b) Alectra Utilities' capital investment needs and solutions are not static. System renewal needs reflect the backlog of deteriorated and emerging increases in volume of assets reaching end of life over the planning period. Alectra Utilities considers each rear lot renewal project as discrete and evaluates the merit of each project relative to all the other proposed investments in the capital investment portfolio. Alectra Utilities' capital investment optimization process considered the project value, risk and available funding to determine the timing of projects approved for each year from 2020 to 2024. Please refer to Capital Investment Optimization process described in Exhibit 4 Tab 1 Schedule 1 Page 342 for a detailed explanation of the process.

c) Alectra Utilities applies CopperLeaf C55 to evaluate the present value of the projects considering the investment, risk and benefits of the projects as per the Value Framework. Table 1, below provides the present value of the scenario to renew the rear lot projects at the planned scheduled compared to a scenario of deferring the projects beyond the DSP planning period (i.e. five-year deferral). For comparison, Alectra Utilities has determined that the deferral scenario best represents the repair alternative. The present value for each value measure is calculated consistent with the Company's Value Framework. Each value measure is calibrated to a common economic scale (1 value point is equivalent to $1,000). Please refer to Exhibit 4, Tab1, Schedule1, Appendix L, page 7. Analysis indicates that deferral of the rear lot renewal beyond the DSP planning period reduces the risk mitigation value of reputation, safety, environment and also reduces the value to reliability improvement and OM&A benefit.

**Table 1 – Present Value Replace vs. Repair Rear Lot Projects as Proposed in the 2020-2024 DSP**

| Value Measure | Present Value Replace | Present Value Repair |
|---|---|---|
| Reputational Risk | 17,351.77 | 10,851.54 |
| Safety Risk | 5,331.17 | 3,349.93 |
| OM&A Benefit | 3,085.12 | 2,111.41 |
| Reliability Benefit | 9,569.65 | 6,020.84 |
| Compliance Risk | 822.95 | 527.62 |
| Environment Risk | 4,104.42 | 2,527.19 |
| Investment | (27,012.58) | (22,294.84) |
| Present Value | 13,252.49 | 3,094.90 |

**EP-29**

**Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B, pages 26 to 28**

**Question:**

a) **Which legacy utility authored a Distribution Automation report?**

b) **Please file a copy of the referenced Distribution Automation report.**

c) **Why is there a sharp drop in spending on distribution automation in 2019?**

**Response:**

a) Alectra Utilities' predecessor, PowerStream, authored the Distribution Automation report.

b) Alectra Utilities provides the referenced Distribution Automation report as attachment EP-29_Attach 1_ Distribution Automation Report.

c) The reduction in spending on Distribution Automation in 2019 is result of the optimization process. Alectra Utilities' capital investment optimization process considers value, risk, timing and available funding to determine projects planning for execution. Please refer to the Capital Investment Optimization process described in Exhibit 4 Tab 1 Schedule 1 Page 342 for additional detail on the process Alectra Utilities applied to the DSP capital investment plan.

# EP-29

# ATTACH 1- Distribution Automation Report

# Distribution Automation Report

## 2015 Update

Prepared by: System Planning
Date: Apr 2015

# Table of Contents

# 1. Executive Summary

PowerStream is striving to lower the overall system wide SAIDI below 60 minutes by 2019. This is a significant undertaking that requires alignment between the coordinated efforts of many departments and the 5 year capital budget plan. One of the major programs identified in achieving this reliability targets is 'Distribution Automation'.

A complete Distribution Automation System (DAS) remotely monitors the distribution system, facilitates supervisory control of devices and provides decision support tools to improve the system performance. A Distribution Automation System will allow PowerStream to implement flexible control of the distribution system, which will enhance efficiency, reliability, and quality of electric service. Flexible control also results in more effective utilization and life-extension of the existing distribution system infrastructure.

In an effort to improve distribution system reliability, PowerStream has an annual 'Distribution Automation Program' and has installed a significant number of switching devices on the primary distribution system to sectionalize and build ties between feeders.

In past years (2009-2014) PowerStream has been installing an average of 23 switches per year to meet the Level 1 requirement of a DAS system. It is determined that PowerStream needs to install 46 N.C Switches or Reclosers to sectionalize feeders as per the feeder segmentation criteria established in the report, and 60 N.O switches to build ties between feeders.

In addition to the Level 1Automation, PowerStream has experimented and gained experience with Level 2 Distribution Automation projects such as Automatic Feeder Restoration (AFR), distributed feeder automation (Intelli-Team), and Fault Detection, Isolation and Restoration (FDIR) projects. Level 2 Automation will continue to expand via an annual AFR program to install additional schemes between 2015 and 2020.

A DA Steering committee and DA Technical Committee were started in 2013/2014 to oversee and manage the development and installation of Distribution Automation at PowerStream. This cross-department group will evaluate and select the devices and technology platform most favorable for wide scale DAS implementation moving forward.

It is recommended that the Distribution Automation Committees continue to oversee all DA Strategy and Technical activities moving forward. The Technical Committee should monitor Level 2 DA pilot projects in 2015 and decide which scheme offers the most value to PowerStream, in order to determine which technology should be focused on for large scale expansion.

There may be a need to invest more in DAS projects to achieve projected reliability targets if other projects in the 'Five Year Reliability Work Plan' fail to deliver SAIDI savings as expected.

# 2. Purpose

Distribution Automation has proven to have a significant benefit to overall system reliability and thus directly supports PowerStream's mission to deliver reliable power to its customers, safely and efficiently.

This report provides a summary of PowerStream's position in regards to Distribution Automation progress, by providing an update in the following key strategic areas:

- Economic justification and criteria for selection of the type, quantity and location of automated devices.
- Existing Distribution Automation adopted within PowerStream service territory.
- Long term strategy for Distribution Automation.

# 3. Background

PowerStream is working to lower the overall system wide SAIDI below 60 minutes by 2019. This is a difficult operation that requires the successful coordination of several key departments and the 5 year capital budget plan.

To manage this effort, a 5 Year Reliability Work Plan has been developed to identify reliability based projects, quantify their effectiveness, and project their expected savings moving forward. Distribution Automation is an important component of the 5 Year Reliability Work Plan that is expected to provide significant CMI savings, and directly contribute to PowerStream's success in reaching its reliability targets.

In September 2005, System Planning issued the Distribution Automation (South) report which discussed the general information about distribution automation philosophy and methodology, economic justification for installation of automated switches and an overview of the automation within PowerStream. This report was subsequently updated in March 2007 outlining the switch requirement from 2007 to 2010.

Following the guidelines of the Distribution Automation South report, a report on Distribution Automation for the North was published in December 2009.

In 2012, a system wide report was published which reviewed the existing distribution automation within PowerStream and proposed a long term strategy and establish a road map for distribution automation within PowerStream.

Since the last issuance of the report in 2012, there have been changes to the overall material and installation costs of Automated Switches and PowerStream's customers per feeder have been increasing. Additionally, the DA Steering Committee has released a 10 year Strategy for DA that the report needs to be aligned with. For this reason, the Distribution Automation report will be updated to reflect current installation costs and feeder customers, and measure PowerStream's DA development with the DA strategy framework.

# 3.0 Categories of Distribution Automation

The Fig-1 shows below the typical Electrical Distribution System in Ontario.

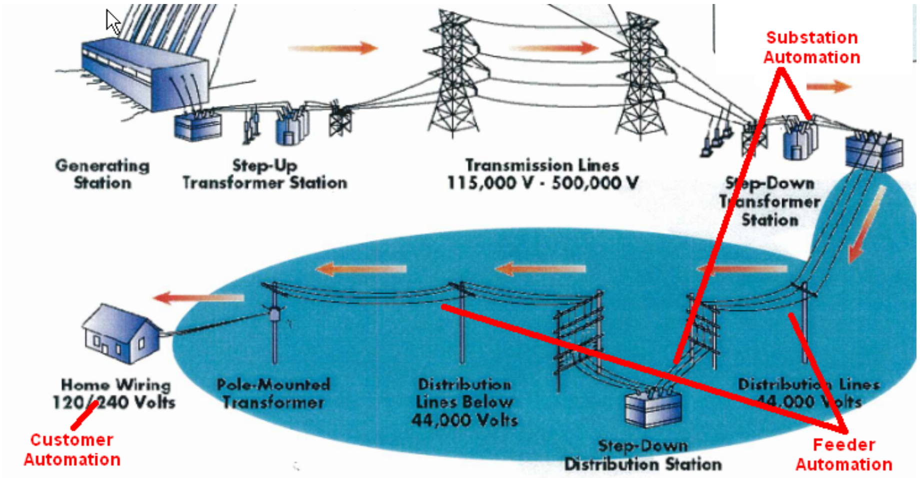


**Fig-1: Typical Distribution System in Ontario**

Since 1970 automation has been maturing, and utilities have begun to embrace DA Technology with wide scale adoption in three categories:

- Substation Automation
- Feeder Automation
- Customer Automation

The functions of each level of automation are shown Table 1 below:

| Substation Automation Functions | Feeder Automation Functions | Customer Interface Automation Functions |
|---|---|---|
| ▪ **Data Acquisition From:**<br>- Circuit Breakers<br>- Load Tap Changers<br>- Capacitor Banks<br>- Transformers<br>▪ **Supervisory Control of:**<br>- Circuit Breakers<br>- Load Tap Changers<br>- Capacitor banks<br>▪ **Fault Location**<br>▪ **Fault Isolation**<br>▪ **Service Restoration**<br>▪ **Substation Reactive Power Control** | ▪ **Data Acquisition From:**<br>- Line Reclosers<br>- Voltage Regulators<br>- Capacitor Banks<br>- Sectionalizers<br>- Line Switches<br>- Fault Indicators<br>▪ **Supervisory Control of:**<br>- Line Reclosers<br>- Voltage Regulators<br>- Capacitor Banks<br>- Sectionalizers<br>- Line Switches<br>▪ **Fault Location**<br>▪ **Fault Isolation**<br>▪ **Service Restoration**<br>▪ **Feeder Reconfiguration**<br>▪ **Feeder Reactive Power Control** | ▪ **Automatic Meter Reading**<br>▪ **Remote Reprogramming of Time-of-Use (TOU) Meters**<br>▪ **Remote Service Connect/Disconnect**<br>▪ **Automated Customer Claims Analysis** |

**Table -1: Functions of Distribution Automation [3]**

# 4.0 Feeder Automation

The primary topic of discussion in this report is distribution feeder automation. Feeder automation is the monitoring and control of devices located on distribution feeders. The following is a summary of the different levels of automation.

## 4.1 Level 0 Automation [1]

This level of automation consists of automatic transfer scheme with two switches that sense loss of voltage from a preferred source and transfers the load to an alternate source. Such a scheme is shown in Fig-2. This level of automation requires a fixed level of redundant capacity, equal to the critical load(s), to be in place at all times to accommodate the transfer scheme.

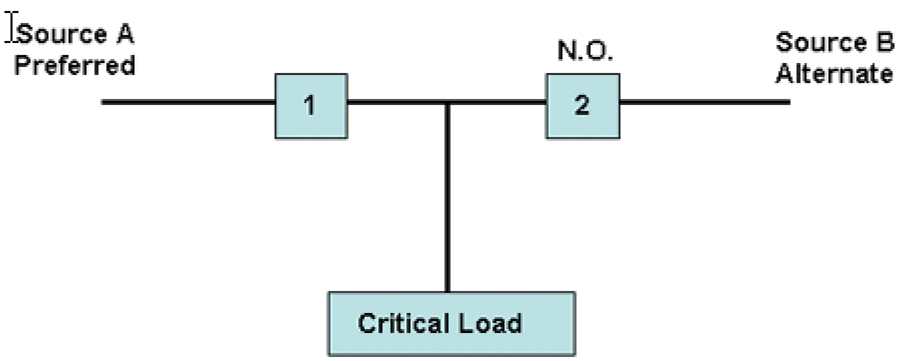


**Fig-2: Level 0 Automatic Transfer Scheme**

## 4.2 Level 1 Automation [1]

This level of automation consists of switches installed with remote operating capability from a dispatch center through a supervisory control and data acquisition (SCADA) system. Such a scheme is shown in Fig-3. The equipment can report loading and status but has no local intelligence or automatic transfer capability. It is an extension of SCADA beyond the substation fence. Hence, it requires a high degree of human intervention and offers little in the way of true automation. Human intervention determines alternate sources of capacity and restoration timelines.

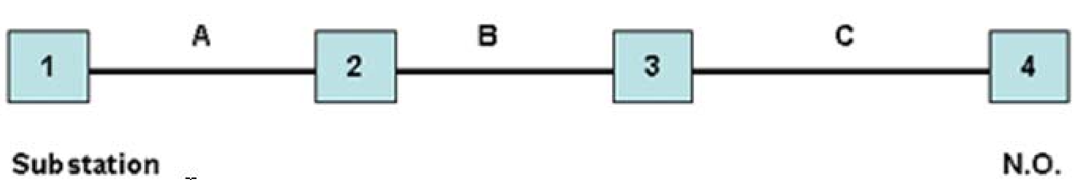


**Fig-3: Level 1 Automation via SCADA**

## *4.3 Level 2 Automation* [1]

This level of automation requires fully automatic fault isolation and restoration activities and represents current state of the art technology in distribution automation. This does not require dispatcher intervention and it is possible to restore power in less than one minute. The two major schemes encompassing Level 2 Automation are:

1. Distributed Feeder Automation System
2. Centralized Feeder Automation Scheme

### 4.3.1 Distributed Feeder Automation Systems

With a distributed approach, feeder automation is accomplished through the coordinated actions of groups of automated switches installed on a relatively small portion of the power system (such as a single distribution feeder or a group of interconnected feeders). This scheme relies on "peer-to-peer" communications between field devices, which enables the field devices to exchange information about observed faults, extended loss of voltage, and pre-fault loading.

It is possible (though not required) to monitor the operation of the distributed feeder automation scheme from a central location.

Major advantages and disadvantages of the distributed approach to feeder automation scheme are identified below:

Advantages:

- The system is designed to complete all necessary switching actions in one minute or less, which is required for maximum SAIDI and SAIFI improvement.
- The system is able to block multiple reclosing shots into known permanent faults.

Disadvantages:

- This scheme is designed to operate in fully automated fashion (i.e., no manual intervention is required). Therefore, the system requires extreme care, considerable amount of training and implementation resources.

Examples of distributed feeder automation schemes include S&C Electric's "IntelliTeam" system and Advanced Control System's "OpEnConnect" substation gateway.

This level of automation has the features of Level 1 but also includes intelligence to provide automatic transfer and reconfiguration of a feeder circuit by transferring portions of the circuit to alternate ties. Such a scheme is shown in Fig.

4 below. Notice that portions of each feeder can be transferred to different tie sources. The system recognizes real time capacity availability/constraints and restores the affected load in the most timely and efficient manner possible.

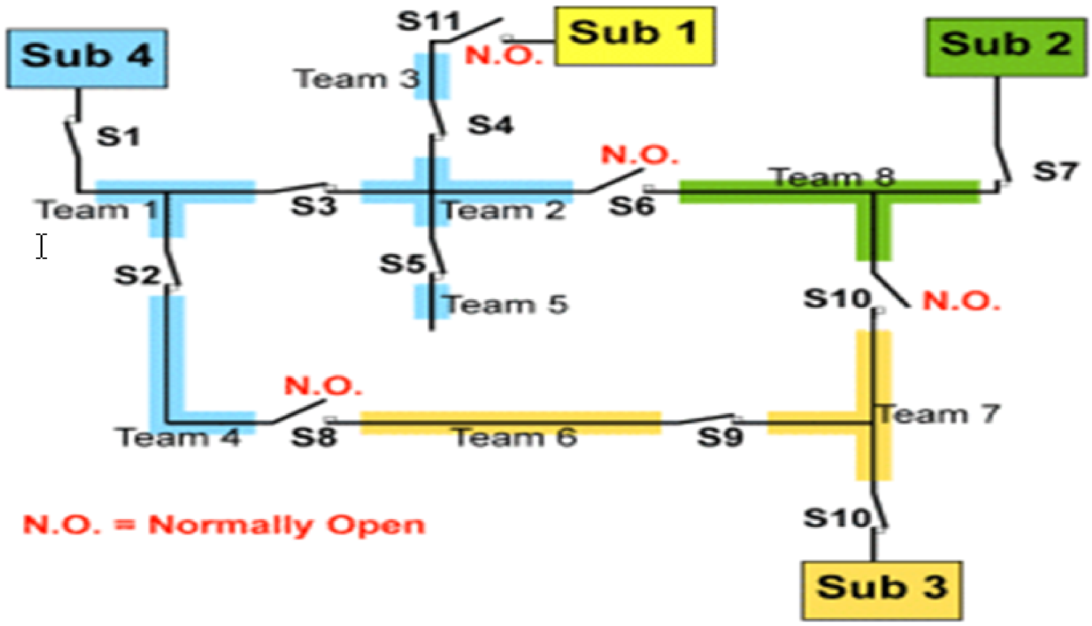


**Fig-4: Level 2 Intelligent Automation (AFR scheme)[1]**

In 2014, PowerStream initiated an IntelliTeam pilot project on feeders 24M8, 26M3, 24M1, 24M5, and 12M3. An evaluation on the success of the project is intended to be completed in 2015 following the successful management of outages on these feeders.

### 4.3.2 Centralized Feeder Automation Schemes

With central feeder automation architecture, electrically operable feeder switches equipped with a RTU and communication facilities are monitored and controlled by a central SCADA system. This system is able to detect feeder faults of all types (Phase-to Ground, Phase-to-Phase, etc), identify the segment of the feeder that contains the fault, and execute control commands to open remote controlled switches as needed to isolate the faulted segment of the feeder. It is also possible for a centralized feeder automation scheme to transfer the load served by un-faulted sections of the feeder to another feeder, with full considerations of loading limitations on the feeder to which load is being transferred.

Centralized feeder automation schemes can be configured as fully-automated schemes (no manual intervention required) or semi-automated schemes (person initiates the switching actions based on the recommendations of the feeder automation system).

Major advantages and disadvantages of the centralized feeder automation scheme are identified below:

Advantages:

- The Dispatcher is always kept informed about the operation of this scheme, even if a fully automated approach is used.
- The system is able to block multiple reclosing into known permanent faults to prevent damage to equipment.
- It is possible to accomplish other feeder automation functions, such as feeder re-configuration and load shedding, without disabling the fault location isolation and service restoration activities.

Disadvantages:

- Centralized Feeder Automation schemes require a central SCADA system with adequate capacity to support the necessary software. This also requires a reliable communication infrastructure that can handle communication with devices located on distribution feeders throughout the service territory.
- Not all centralized schemes are able to restore power to customers in one minute or less. Some schemes require operator decision-making time and can take up to five minutes to perform an operation.

In 2013 and 2014, PowerStream initiated Automatic Feeder Restoration (AFR) projects on the following feeders:

- 2013 - 20M21 and 5122M11 (Vaughan, VTS#1 –VTS#1)
- 2013 - 20M22 and 36M3 (Vaughan-Richmond Hill, VTS#1 - RHTS#1 )
- 2014 - 26M16 and 26M4 (Markham, MTS#3E – MTS#3)

Due to system re-configurations to accommodate municipal construction projects, the original AFR project on the 20M21 and 5122M11 has not yet been fully initialized. All AFR projects are expected to be activated by the latter half of 2015.

PowerStream has applied automatic transfer scheme automation (Level 0) for some of its critical customer such as hospitals and some industrial customers.

PowerStream has elements of Level 1 feeder automation functionality throughout the distribution system. The equipment can report current status but has no local intelligence or automatic transfer capability. It requires a high degree of engagement from Control Room and offers little in the way of true automation. The Control Room determines alternate sources of capacity and restoration timelines.

PowerStream has initiated the following Level 2 Automation projects:

- S&C Electric's "IntelliTeam" system
    - Restoration in less than 1 minute
- Automatic Feeder Restoration (AFR)
    - Restoration in milliseconds
- Fault Detection, Isolation and Restoration (FDIR).
    - Restoration in less than 1 minute.

# 5.0 Benefits of Automated Devices [1]

As important components of distribution and feeder automation, RTU controlled devices on the distribution system provide the following benefits:

- Allows for rapid transfer of loads between feeders or stations during emergency situations without deployment of lines crew.

- Increases assets utilization and defers capital investment by increasing feeder and station loading capability through flexible load transfer response versus a fixed load transfer response scheme.

By using RTU controlled devices, a feeder can be sectionalized into multiple segments. During an outage or fault, loads on a feeder can be transferred to different feeders in segments. Therefore, all feeders can be loaded higher without risk of overloading, since they only need to reserve capacity to pick up a segment of other feeders, not the whole feeder as is the case with no automation.

Automated devices provide other benefits such as:

- Reduction of restoration time and improvement of supply reliability to customers, and increased revenue. Automated switches show their value the most when large outages occur. The outages often occur after hours when there are no line crews on shift. With the use of the RTU controlled switches, power can be restored within minutes as opposed to one hour plus when a crew has to respond from home to operate manual switches.

- Provide the ability and flexibility to optimize the distribution system through:

    - Reconfiguration to avoid station and feeder over loading during summer peak periods and outages.
    - Reduction of station peak demand.
    - Reduction of feeder and station power losses which will reduce capital investment and operation costs.

- Provide the ability to monitor and improve power quality such as voltage and power factor through control of the distributed capacitor banks. Power quality information also can be used for engineering and planning.

- Cold load pick up coordination and load transfer predictability through current measurement telemetry.

- Perform routine switching remotely for maintenance purposes and improve the productivity of field crews by reducing the time required to complete switching operations (planned and unplanned work).

- Reduction of risk of personnel injury during switching, as the crew does not have to be in physical contact with the switch.

- Provide a platform for Level 2 distribution automation systems. Since the number of feeders and stations is increasing as the distribution system grows, the need for an intelligent distribution automation system increases.

## 5.1 Justification of Automated Devices [4]

Segmenting feeders into smaller sections with Automated Switches/Reclosers will result in reliability improvements.

Criteria are needed to balance automation cost with the value of improved reliability to PowerStream and customers. The quantity of RTU controlled devices and locations of switches on feeders need to be optimized to obtain the best value for the investment.

The following sections review the justification for Normally Closed (N.C.) and Normally Open (N.O.) switches/reclosers on the distribution feeder.

### 5.1.1 Normally Closed Switches/Reclosers [4]

The reliability improvement in terms of SAIDI and customers interrupted must be quantified and criteria must be established to determine the optimum number of switches in relation to unsupplied energy costs and customer cost.

Reliability Improvement using Automatic Switches/Reclosers

The % SAIDI improvement with distribution automation can be quantified by the following formula assuming all the devices have a suitable downstream source.

With no devices initially available on the feeder the improvement can be calculated as:

% Improvement = NSW/ (NSW+1) *100
Where NSW is # No of normally closed switches/reclosers
For e.g. if the NSW = 3, % improvement = 3/ (3+1)* 100 = 75%

As shown in the Fig -5, usually 2-3 DA switches per feeder represents the best value for investment and the reliability improvement return diminishes as more switches are added. However it might be advisable to install more switches due to load transfer constraints, critical customers and unusual feeder configuration.

The placements of the switches play a vital role in the predicted reliability improvement. It is important to note that splitting customers equally works best only when the customers and fault exposure are evenly distributed on the feeder.

It is required that the customer distribution and feeder outages be studied before deciding on the switch placement on a given feeder.

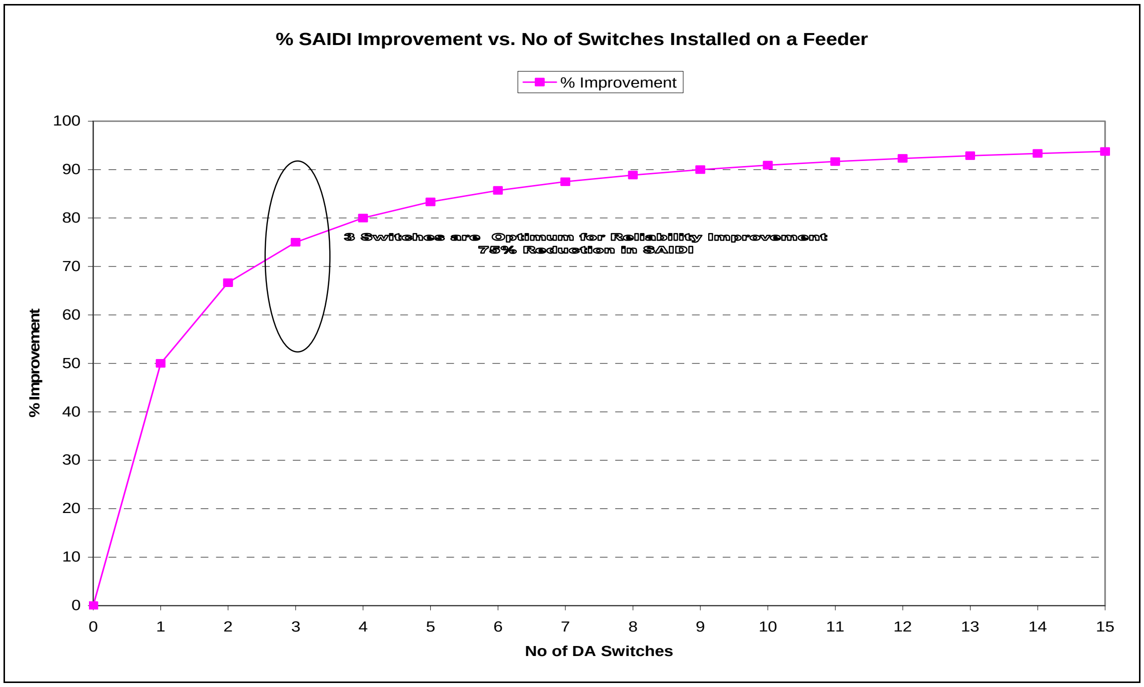


**Fig-5: % SAIDI Improvement vs. No of Switches Installed (Diminishing Return)**

If there are already automated switches/reclosers installed on the feeder the % improvement can be calculated as follows:

% Improvement = 0.5 * NSW/ (NSW+1) * 100

Economic Consideration

Cost of Automated Devices: (Switch/Recloser in addition to RTU unit)
There are several different switches that can be used as part of the DAS. The following are the typical cost of devices that are currently used in PowerStream territory including installation.

- S&C ScadeMate Switch (27.6 kV) = $ 78,496
- 600A LIS with SEECO motor operation (44 kV) = $154,263
- G&W Viper Recloser (27.6 kV) = $70,242

Criteria to establish the number of required switches to deliver the improved reliability has been documented in various sources (see below). Industry standards apply customer kilometers to establish segmentation requirements.

Included in Reference No.2 is a report titled "Distribution Automation – How Much?" Applying this philosophy and using PowerStream's outage information and unsupplied energy costs customer-km are calculated to justify what level of automation would need to be applied.

The reliability calculations for the PowerStream Electrical System are as follows:

- System maximum peak P max= 1,985 MW
- System Customer Numbers N= 356,643
- Customer value of unsupplied energy V= $20/kWh (from System Planning Philosophy)
- Assume average annual fault rate for main line or feeder level outages = 0.19/km (typical fault rate: 0.1 to 0.5 /mile, or 0.06/km to 0.3/km)
- Average duration of main line or feeder level outage = 65.82 minutes (PowerStream 3 year average)
- Average cost of adding a segmentation point (RTU controlled switch):
  - $74,369 (27.6 kV)
  - $154,263 (44 kV)

i. 1 minute SAIDI = Number of customers*1 minute
= 356,643 CMI (Customer Minutes Interrupted)

ii. The cost of one hour system outage
=P max in kW * 1 Hour * V
=1,985, 000 kW*1 hour* $20/kWh
= $39,700,000 (for one hour)

iii. The cost of 1 CMI

$$= \frac{\text{P max in kW * 1 Hour * V}}{\text{N*60}}$$

$$= \frac{1{,}985{,}000\text{* 1hr * 20}}{356{,}643\text{*60}}$$

= $1.86 (cost per CMI)

iv. The average annual CMI for a kilometer of line with one customer:
= 0.19 * 65.82
= 12.51

v. The value of a customer-kilometer of line to justify the increased segmentation is then:
= 12.51 * $1.86
= $23.20

vi. Therefore, the customer kilometers to justify added segmentation equals to:

a. Based on Average switch cost for 44kV (Used in north area):
= $154,263 / $23.20
= 6,649

b. Based on Average switch cost for 27.6kV(Used in south area):
= $74,369 / $23.20
= 3,205

The criteria established above require 6,649 customer kilometers in the north area and 3,205 customer kilometers in the south area as a minimum to equal the reliability improvement value to PowerStream.

If the cost of devices and installation changes in future it is crucial that a new analysis be completed to compute the cust-km to justify added segmentation.

Feeder Segmentation Calculation [4]

A hypothetical feeder of 10 kilometers in length with a customer count of 3,000 as shown in Fig-6 is studied

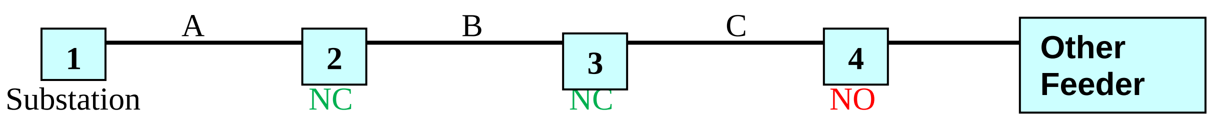


**Fig. 6: Segmentation of a typical feeder**

It is assumed that there are customers, length and fault rate are equal for each segment. The number of outages of each segment is dependent on the fault rate and the length of line being segmented or protected by the segmentation device.

The primary rule when applying segmentation strategies such as automation is that it is the customers NOT interrupted by the outages which receive the CMI benefit.

For example, if a fault occurs in section B, then section B will be automatically isolated by opening switch 2 and 3, section C will be fed from an adjacent feeder by closing switch 4. Therefore, 2 of the total 3 segments will receive the CMI benefit (avoided CMI).

The CMI benefits on a feeder were calculated for the different number of switches possibilities. The results are shown in Table 2:

| # of Switches (A) | # of Segments (B) | km per Segment (C) | Customers per Segment (D) | Customers **NOT** experiencing outage (E) | CMI Benefit in Customers-kilometers (F) |
|---|---|---|---|---|---|
| | B=A+1 | C=L/B | D=N/B | E=N-D | F=E*C |
| 1 | 2 | 5.0 | 1,500 | 1,500 | 7,500 |
| 2 | 3 | 3.3 | 1,000 | 2,000 | 6,667 |
| 3 | 4 | 2.5 | 750 | 2,250 | 5,625 |
| 4 | 5 | 2.0 | 600 | 2,400 | 4,800 |
| 5 | 6 | 1.7 | 500 | 2,500 | 4,167 |
| 6 | 7 | 1.4 | 429 | 2,571 | 3,673 |
| L=10 Length of the feeder in km<br>N=3000 Number of customers on the feeder | | | | | |

**Table 2: Segmentation of a typical feeder [2]**

Table 2 shows that, when the feeder is broken into 5 segments (4 Switches), the CMI benefit would be 4,800 customer-kilometers, which is greater than the threshold of 4,353. When the feeder is broken into 6 segments, the CMI benefit would be 4,167 customer-kilometers which is less than the threshold of 4,353. Therefore, it can be justified to install up to 4 RTU switches along the feeder in this example.

### 5.1.2. Normally Open Switches [4]

Normally open RTU Switches establish tie points between feeders and allow rapid load transferring between feeders when needed.

Figure 7 illustrates how a typical outage restoration scenario might progress both with and without advanced feeder automation. The times shown will be extended even further during storm conditions when dispatchers are juggling multiple outage events.

Fig. 7 shows that without distribution automation, it takes 50-80 minutes to restore power to customers on un-faulted segments of a faulty feeder. However, restoration time can be reduced to less than 5 minute with distribution automation, and in some cases even prior to customers' reporting the loss of power if there are adequate tie points and segmentation are available within the feeder.

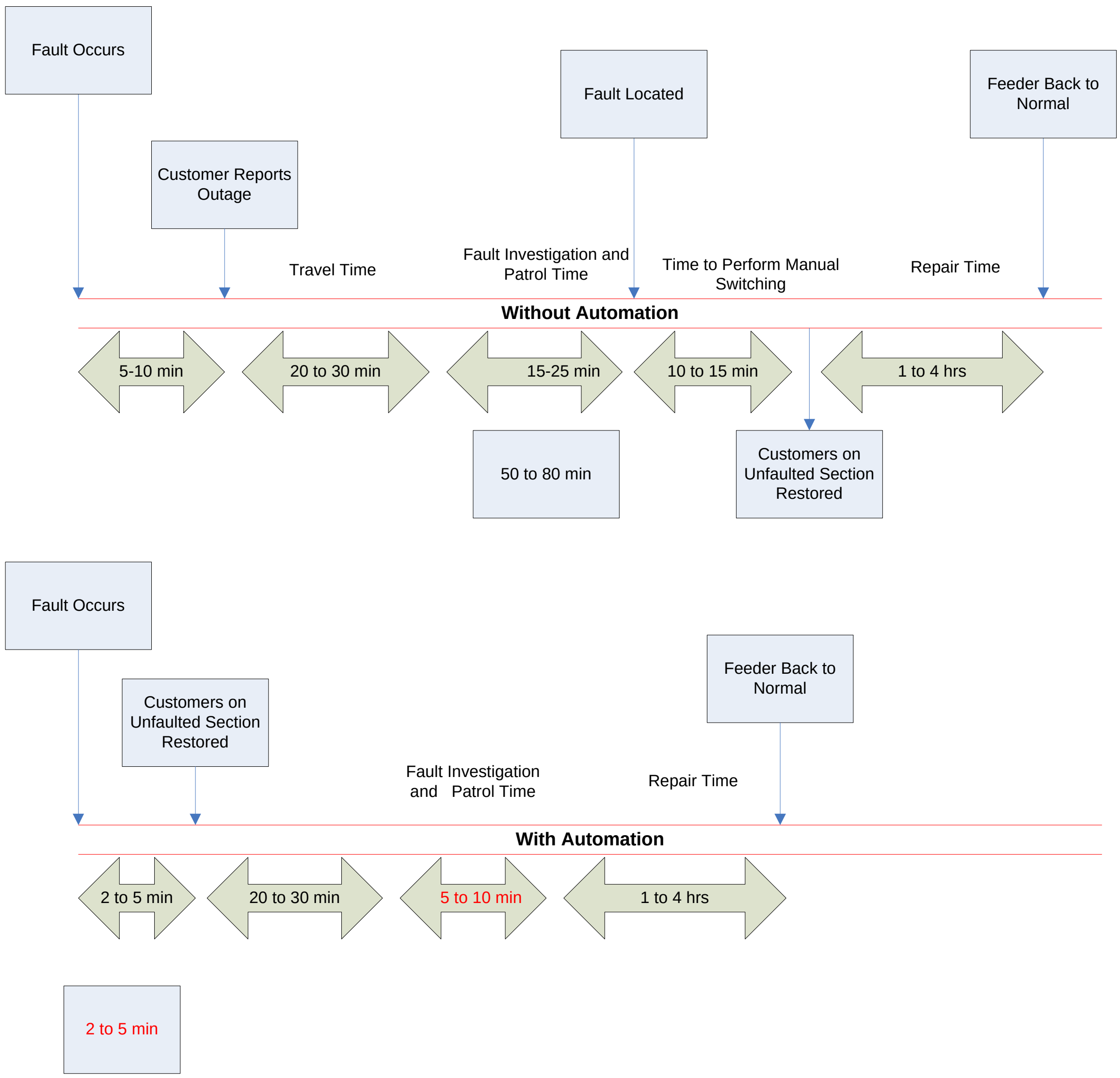


**Fig-7: Outage Restoration With and Without Distribution Automation**

# 6.0 Existing System Configuration and Distribution Automation

PowerStream has employed SCADA to monitor and control its distribution system since the late 1980's.

Automation at the transformer station level in PowerStream is very comprehensive. It includes data acquisition from circuit breakers, load tap changers, capacitor banks and transformers as well as supervisory control of circuit breakers, load tap changers, and capacitor banks.

As for automation at the feeder level, PowerStream has applied automatic transfer (Level 0) automation for some critical customers such as: hospitals, large industrial customers, and public entertainment facilities such as Paramount Canada's Wonderland.

In order to improve system reliability there was an effort in former utilities to install switches to sectionalize feeders and build feeder ties. This has resulted in good penetration of automated and manual switches, however has resulted in inconsistent distribution, device specification and somewhat inefficient placement within the system. PowerStream has installed a total of 364 RTU switches on distribution feeders (Level 1 automation).

In addition to the level 1 Automation PowerStream has initiated Level 2 Automation projects such as Automatic Feeder Restoration schemes on selected Greenwood and Jackson feeders in 2013, and select Cockburn feeders in 2014. In addition an FDIR scheme based on Survalent technologies has been installed on Richmond Hill MTS# 1 and MTS#2 feeders.

The existing switches are categorized in two broad categories based on their operation within the system:

- Manual Switches
- RTU Controlled Switches

## *6.1 Manual Switches*

The switching devices currently installed on the overhead PowerStream distribution system are as follows:

2032 and 1516 manual switches are installed in South and North respectively as per Tables 3 and 4.

| Municipality | 44.0kV | 27.6kV | 13.8kV | 8.3kV |
|---|---|---|---|---|
| Aurora | 169 | 13 | 204 | |
| King | 3 | 2 | 1 | 1 |
| Markham | | 549 | 28 | 59 |
| Richmond Hill | | 210 | 1 | |
| Vaughn | 8 | 748 | 3 | 33 |
| Total | 180 | 1522 | 237 | 93 |

**Table 3: Manual Overhead Switches South**

| Municipality | 44.0kV | 27.6kV | 13.8kV | 8.3kV | 4.16kV |
|---|---|---|---|---|---|
| Alliston | 71 | | 73 | 7 | 34 |
| Barrie | 390 | | 239 | | 304 |
| Beeton | 11 | | 19 | | |
| Bradford | 70 | | 77 | | |
| Newmarket | 20 | | | | |
| Penetanguishene | 42 | | | 4 | 78 |
| Thornton | | | | 5 | |
| Tottenham | 24 | 2 | 1 | 43 | 2 |
| Total | 628 | 2 | 409 | 59 | 418 |

**Table 4: Manual Overhead Switches North**

## 6.2 RTU Controlled Switches

The automated switching devices currently installed on PowerStream distribution system can be categorized in two broad categories:

- Overhead Devices
- Underground RTU Devices

Overhead devices consist of: S&C ScadaMate Switches, S&C Alduti switches and G&W Reclosers.

312 and 52 RTU Controlled witches are installed in South and North respectively as per Tables 5 and 6.

| Municipality | 27.6kV | 13.8kV | 8.3kV |
|---|---|---|---|
| Aurora | 7 | | |
| Markham | 138 | 5 | 1 |
| Richmond Hill | 47 | | |
| Vaughn | 114 | | |
| Total | 306 | 5 | 1 |

**Table 5: RTU Overhead Switches South**

| Municipality | 44.0kV | 13.8kV |
|---|---|---|
| Alliston | 2 | |
| Barrie | 41 | 2 |
| Bradford | 4 | |
| Penetanguishene | 3 | |
| Total | 50 | 2 |

**Table 6: RTU Overhead Switches North**

The S&C Alduti switches are close to end of life and are expected to be replaced within the next 5 years.

There are 29 Underground RTU Devices consisting of S&C PMH, Vista, G&W PVI, and PPI switchgear, as per Table 7.

| Item/Area | PMH | PVI | PPI | Vista |
|---|---|---|---|---|
| Richmond Hill | 18 | 1 | 2 | 0 |
| Markham | 1 | 4 | 0 | 3 |
| Total | 19 | 5 | 2 | 3 |

**Table 7: RTU Pad Mount Switchgears South**

## *6.3 RTU Switch per Feeder*

44kV Feeders:

There are 17 x 44 kV feeders supplied from the 7 Hydro One owned transformer stations in North. The number of RTU controlled switches per feeder is shown in Table 8.

| Item | Quantity |
|---|---|
| Number of Feeders | 17 |
| Total No of RTU switches | 52 |
| N.C. RTU switches | 29 |
| N.O. RTU switches | 23 |
| Avg RTU switches/ Feeder | 3.06 |
| Avg N.C. RTU switches/ Feeder | 1.71 |
| Avg N.O. RTU switches/ Feeder | 1.35 |

**Table 8: Switch Per feeder (North)**

27.6kV Feeders:

There are 142 x 27.6 feeders supplied from the 15 PowerStream owned transformer stations.

The number of RTU controlled switches per feeder in the South is shown in Table 9.

| Item | Area | | |
|---|---|---|---|
| | Markham | Richmond Hill | Vaughan |
| Number of Feeders | 57 | 26 | 59 |
| Total No of RTU switches | 144 | 47 | 114 |
| N.C. RTU switches | 74 | 27 | 56 |
| N.O. RTU switches | 70 | 20 | 58 |
| RTU switches per Feeder | 2.53 | 1.81 | 1.93 |
| N.C. RTU switches per Feeder | 1.30 | 1.04 | 0.95 |
| N.O. RTU switches per Feeder | 1.23 | 0.77 | 0.98 |

**Table 9: Switch Per Feeder (South)**

## 6.4 Need for Additional RTU Controlled Switches

Need for Normally Closed Switches/Reclosers

Most 27.6 kV feeder components are rated 600 A. However, the ratings of feeder's egress cables vary significantly depending on cable material and construction, and installation configuration. Station egress feeders have ampacity ratings that vary from 333 A (some feeders in Markham) to 600 A (some feeders in Vaughan).

As per the PowerStream loading criteria all 44 kV feeders in North should have a maximum of 400 amps (approx. 30 MVA) under normal operating condition and 600 A (approx. 46 MVA) under contingency condition.

| Area/Voltage | Average Feeder Load | # of NC Switches per Feeder | Loading per Feeder Segment | Loading with one Segment from Other feeder |
|---|---|---|---|---|
| Barrie (44kV) | 287 | 1.71 | 106.07 | 393.07 |
| Markham (27.6kV) | 186 | 1.30 | 80.86 | 266.86 |
| Richmond Hill (27.6kV) | 242 | 1.04 | 118.63 | 360.63 |
| Vaughan (27.6kV) | 286 | 0.95 | 146.67 | 432.67 |

**Table-10: Average Feeder Loading vs. RTU Switch**

Table-10 indicates that on average, the feeders are capable of handling the overload if it feeds one segment from another feeder in the event of emergency and no additional sectionalizing is required by placing additional RTU controlled N.C. switches. However, additional sectionalizing is required to increase the reliability.

Optimal feeder segmentation was performed on all the 27.6 kV and 44 kV feeders by applying the following criteria:

- The quantities should be economically justified as per the criteria outlined in section 3.2.

- The number of the switches obtained by cust-km criteria (A) is compared with the number of switches required to achieve optimum reliability improvement (C). If the number of switches proposed by cust-km (A) is greater than the reliability improvement(C) then it is proposed to limit the number of switches to the reliability improvement value, as installing more switches will not lead to significant increase in reliability. If the number of switches obtained by cust-km is less than the optimum reliability improvement, then it is proposed to install switches as justified economically by cust-km criteria.

The analysis considers that customers are evenly distributed along the length of the feeder. The requirement on the number of switches is likely to differ if the load and customer distribution is taken into account. When proposing the location of switches on these feeders it is required that an in depth review of load and customer distribution be completed. The feeder segmentation was performed on all the 27.6 kV and 44 kV feeders and optimal switch quantities determined. Table 11 shows the results of the segmentation analysis and the estimated SAIDI improvement by addition of RTU devices.

| # | Feeder | Feeder Voltage | Feeder Customers | Feeder Length (km) | Optimum # of N.C. Switch as per Cust-km Criteria | Existing # of N.C. RTU switches | Switch Required based on Reliability Improvement | Optimum # of N.C. Switch Required based on Reliability Improvement | # of N.C. Switches Required as per Cust-km Criteria | Optimum # of New Switches | Reliability Improvement (%) | SAIDI Contribution (2011-2013) | SAIDI Improvement (min) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (A) | (B) | ( C ) | (2-B) | (A-B) | (C-B) | | | |
| 1 | **36M3** | 27.6 | 2831 | 22.9 | 18 | 0 | 2 | 2 | 18 | **2** | 66.67 | 0.20 | 0.13 |
| 2 | **20M4** | 27.6 | 4468 | 14.1 | 17 | 0 | 2 | 2 | 17 | **2** | 66.67 | 0.60 | 0.40 |
| 3 | **5122M12** | 27.6 | 5147 | 12.1 | 17 | 0 | 2 | 2 | 17 | **2** | 66.67 | 0.32 | 0.21 |
| 4 | **138M6** | 44.00 | 4528 | 20.6 | 11 | 0 | 2 | 2 | 11 | **2** | 66.67 | 1.48 | 0.98 |
| 5 | **41M41** | 44.00 | 6065 | 14.2 | 10 | 0 | 2 | 2 | 10 | **2** | 66.67 | 0.00 | 0.00 |
| 6 | **41M44** | 44.00 | 4211 | 15.5 | 7 | 0 | 2 | 2 | 7 | **2** | 66.67 | 0.10 | 0.07 |
| 7 | **23M8** | 44.00 | 3742 | 15.7 | 6 | 0 | 2 | 2 | 6 | **2** | 66.67 | 1.78 | 1.19 |
| 8 | **41M14** | 44.00 | 6065 | 9.1 | 6 | 0 | 2 | 2 | 6 | **2** | 66.67 | 0.03 | 0.02 |
| 9 | **27M12** | 27.6 | 1926 | 11.8 | 4 | 0 | 2 | 2 | 4 | **2** | 66.67 | 0.46 | 0.31 |
| 10 | **41M43** | 44.00 | 3526 | 13.2 | 4 | 0 | 2 | 2 | 4 | **2** | 66.67 | 0.00 | 0.00 |
| 11 | **80M25** | 27.6 | 2339 | 8.7 | 4 | 0 | 2 | 2 | 4 | **2** | 66.67 | 0.19 | 0.12 |
| 12 | **153M4** | 44.00 | 4813 | 7.5 | 3 | 0 | 2 | 2 | 3 | **2** | 66.67 | 0.08 | 0.06 |
| 13 | **80M12** | 27.6 | 2181 | 8.1 | 3 | 0 | 2 | 2 | 3 | **2** | 66.67 | 0.96 | 0.64 |
| 14 | **27M8** | 27.60 | 5987 | 28.4 | 51 | 1 | 2 | 1 | 50 | **1** | 25.00 | 0.53 | 0.13 |
| 15 | **20M21** | 27.60 | 6842 | 23.3 | 47 | 1 | 2 | 1 | 46 | **1** | 25.00 | 0.58 | 0.14 |
| 16 | **5122M10** | 27.60 | 5919 | 15.6 | 26 | 1 | 2 | 1 | 25 | **1** | 25.00 | 0.13 | 0.03 |
| 17 | **5122M11** | 27.60 | 4379 | 20.6 | 26 | 1 | 2 | 1 | 25 | **1** | 25.00 | 0.16 | 0.04 |
| 18 | **23M25** | 44.00 | 8224 | 19.0 | 21 | 1 | 2 | 1 | 20 | **1** | 25.00 | 0.05 | 0.01 |
| 19 | **20M12** | 27.60 | 4164 | 16.2 | 19 | 1 | 2 | 1 | 18 | **1** | 25.00 | 0.23 | 0.06 |
| 20 | **23M24** | 44.00 | 9115 | 14.2 | 17 | 1 | 2 | 1 | 16 | **1** | 25.00 | 1.07 | 0.27 |
| 21 | **20M10** | 27.60 | 3339 | 16.7 | 15 | 1 | 2 | 1 | 14 | **1** | 25.00 | 0.16 | 0.04 |
| 22 | **12M3** | 27.60 | 1306 | 34.4 | 11 | 1 | 2 | 1 | 10 | **1** | 25.00 | 0.30 | 0.08 |
| 23 | **26M12** | 27.60 | 3402 | 12.2 | 10 | 1 | 2 | 1 | 9 | **1** | 25.00 | 0.30 | 0.08 |
| 24 | **27M9** | 27.6 | 2316 | 16.6 | 9 | 1 | 2 | 1 | 8 | **1** | 25.00 | 0.37 | 0.09 |
| 25 | **98M3** | 44.00 | 2522 | 31.2 | 9 | 1 | 2 | 1 | 8 | **1** | 25.00 | 0.42 | 0.10 |
| 26 | **20M9** | 27.60 | 1912 | 15.5 | 7 | 1 | 2 | 1 | 6 | **1** | 25.00 | 0.14 | 0.04 |
| 27 | **36M2** | 27.60 | 2289 | 13.1 | 7 | 1 | 2 | 1 | 6 | **1** | 25.00 | 0.28 | 0.07 |
| 28 | **27M2** | 27.6 | 2501 | 10.7 | 6 | 1 | 2 | 1 | 5 | **1** | 25.00 | 0.46 | 0.11 |
| 29 | **27M6** | 27.60 | 2855 | 7.0 | 4 | 1 | 2 | 1 | 3 | **1** | 25.00 | 0.53 | 0.13 |
| 30 | **26M13** | 27.60 | 2108 | 8.4 | 3 | 1 | 2 | 1 | 2 | **1** | 25.00 | 0.63 | 0.16 |
| 31 | **98M7** | 44.00 | 1207 | 31.6 | 3 | 1 | 2 | 1 | 2 | **1** | 25.00 | 0.00 | 0.00 |
| 32 | **153M3** | 44.00 | 2306 | 12.7 | 1 | 0 | 2 | 2 | 1 | **1** | 50.00 | 0.00 | 0.00 |
| 33 | **36M6** | 27.60 | 1341 | 12.1 | 2 | 1 | 2 | 1 | 1 | **1** | 25.00 | 0.35 | 0.09 |
| | | | | | | | | | Total New N.C. Switches Required | **46** | 42.17 | | 5.80 |

| | |
|---|---|
| CMI Improvement | 2,032,123 |
| Estimated Project Cost | $4,646,000 |
| $/CMI | $2.29 |

**Table-11: Additional N.C. Switch/Recloser Requirement and Projected Reliability Improvement**

Needs for Normally Open RTU Controlled Switches

Table 8 and 9 shows that in 2014, on average, there are 1.23 normally open RTU switches per feeder in Markham, 0.77 per feeder in Richmond Hill, 0.98 per feeder in Vaughan and 1.35 per feeder in the North service territory. Each feeder should have 2 to 3 normally open RTU switches connecting to other feeders in order to rapidly transfer load groups of less than 150 A to other feeders without causing overloading on other feeders.

By applying the criteria of 150 A per segment, the requirement for Normally Open switches per feeder is calculated as shown in Table 12.

| # | Feeder | Feeder Voltage | Load (A) | Feeder Customers | Feeder Length (km) | # of N.O. RTU Points *Required* | # of *Existing* N.O. RTU Points NEW | # of New RTU Points Required |
|---|---|---|---|---|---|---|---|---|
| 1 | 10M10 | 27.60 | 221 | 75 | 6.6 | 1 | 0 | 1 |
| 2 | 10M8 | 27.60 | 167 | 15 | 5.1 | 1 | 0 | 1 |
| 3 | 138M6 | 44.00 | 483 | 4528 | 20.6 | 3 | 0 | 3 |
| 4 | 138M7 | 44.00 | 214 | 2901 | 19 | 1 | 0 | 1 |
| 5 | 21M10 | 27.60 | 315 | 875 | 7.8 | 2 | 0 | 2 |
| 6 | 21M2 | 27.60 | 208 | 153 | 3.1 | 1 | 0 | 1 |
| 7 | 21M5 | 27.60 | 235 | 1092 | 0.5 | 2 | 0 | 2 |
| 8 | 21M6 | 27.60 | 304 | 1674 | 0.5 | 2 | 0 | 2 |
| 9 | 21M9 | 27.60 | 375 | 492 | 1.3 | 2 | 0 | 2 |
| 10 | 27M11 | 27.60 | 276 | 1378 | 6 | 2 | 0 | 2 |
| 11 | 27M2 | 27.60 | 210 | 2501 | 10.7 | 1 | 0 | 1 |
| 12 | 27M9 | 27.60 | 339 | 2316 | 16.6 | 2 | 0 | 2 |
| 13 | 41M11 | 44.00 | 75 | 118 | 8.5 | 1 | 0 | 1 |
| 14 | 41M14 | 44.00 | 320 | 6065 | 9.1 | 2 | 0 | 2 |
| 15 | 41M41 | 44.00 | 273 | 6065 | 14.2 | 2 | 0 | 2 |
| 16 | 41M43 | 44.00 | 229 | 3526 | 5.8 | 2 | 0 | 2 |
| 17 | 41M44 | 44.00 | 240 | 4211 | 15.5 | 2 | 0 | 2 |
| 18 | 45M4 | 27.60 | 420 | 2053 | 37.4 | 3 | 0 | 3 |
| 19 | 55M11 | 27.60 | 178 | 163 | 6.2 | 1 | 0 | 1 |
| 20 | A-8F1 | 27.60 | 95 | 53 | na | 1 | 0 | 1 |
| 21 | 12M4 | 27.60 | 376 | 1988 | 5.7 | 3 | 1 | 2 |
| 22 | 12M5 | 27.60 | 289 | 584 | 11.1 | 2 | 1 | 1 |
| 23 | 13M4 | 44.00 | 379 | 324 | 0.8 | 3 | 1 | 2 |
| 24 | 153M4 | 44.00 | 294 | 4813 | 7.5 | 2 | 1 | 1 |
| 25 | 20M1 | 27.60 | 251 | 201 | 5.3 | 2 | 1 | 1 |
| 26 | 20M10 | 27.60 | 364 | 3339 | 16.7 | 2 | 1 | 1 |
| 27 | 20M11 | 27.60 | 353 | 423 | 5.1 | 2 | 1 | 1 |
| 28 | 20M9 | 27.60 | 319 | 1912 | 17.2 | 2 | 1 | 1 |
| 29 | 21M11 | 27.60 | 293 | 236 | 1.5 | 2 | 1 | 1 |
| 30 | 21M3 | 27.60 | 486 | 825 | 9.5 | 3 | 1 | 2 |
| 31 | 23M26 | 44.00 | 516 | 1160 | 5 | 3 | 1 | 2 |
| 32 | 23M8 | 44.00 | 397 | 3742 | 4.4 | 3 | 1 | 2 |
| 33 | 26M1 | 27.60 | 257 | 1514 | 7.9 | 2 | 1 | 1 |
| 34 | 26M11 | 27.60 | 327 | 4729 | 8.7 | 2 | 1 | 1 |
| 35 | 5122M6 | 27.60 | 231 | 164 | 11.4 | 2 | 1 | 1 |
| 36 | 21M8 | 27.60 | 416 | 2547 | 13.8 | 3 | 2 | 1 |
| 37 | 23M24 | 44.00 | 395 | 9115 | 14.2 | 3 | 2 | 1 |
| 38 | 5122M11 | 27.60 | 437 | 4379 | 13.9 | 3 | 2 | 1 |
| 39 | 5122M9 | 27.60 | 386 | 9091 | 19.0 | 3 | 2 | 1 |
| 40 | 80M12 | 27.60 | 405 | 2181 | 8.1 | 3 | 2 | 1 |
| 41 | 20M3 | 27.60 | 536 | 3874 | 22.3 | 4 | 3 | 1 |

| | |
|---|---|
| Total New N.O. Switches Required | **60** |
| Estimated Project Cost | $6,060,000 |

**Table-12: Additional N.O. Switch Requirement**

# 7.0 Automated Devices for Future

Table 13 lists all the Distribution Automation device vendors and product offerings that PowerStream can investigate to use for its Distribution Automation needs:

| Vendor | Product | Rating | Fault Interrupting | Load Break | Pole Mount | Pad Mount |
|---|---|---|---|---|---|---|
| S&C | ScadaMate Switch | 25kV | | x | x | |
| | Intellirupters | 15kV | x | x | x | |
| | Tripsaver II Recloser | 15kV | x | x | | |
| | PMH Switchgear | 15kV, 25kV | x | x | | x |
| | Vista | 15.5kV, 29kV, 38kV | x | | | |
| | Alduti-Rupter Swich | 46kV | x | x | x | |
| G&W | Viper Recloser | 35kV | x | x | x | |
| | PVI Switchgear | 15.5kV, 27kV, 38kV | x | x | | x |
| | Solid Dielectric Switchgear | 29kV | x | x | | x |
| T&B | Elastimold Recloser | 29kV | x | x | x | |
| | Elastimold Molded Vacuum Switch | 15.5kV, 27kV, 38kV | x | x | | x |
| | Solid Dielectric Switchgear | 29kV | x | x | | x |

**Table-13: Distribution Automation Device Vendors**

The RTU devices that are currently in use at PowerStream's south territory are as follows:

S&C SCADA-Mate Switch:

These devices exist in South service territories. The advantages of these are:

- Remote control-close, remote sensing of voltage, current and power factor.
- Integrated control and communication.
- No time current coordination with upstream protective devices.
- Visible break available to meet Operation requirements.

The following are the disadvantages:

- SF6 gas insulation. There is a concern of environmental regulations being imposed on the SF6 devices.
- Does not reduce MAIFI.
- No reduction in through fault current for transformer.

Reclosers

PowerStream has been installing reclosers since 2012. They offer the following advantages:

- Vacuum insulated.
- Sense and interrupt fault currents and automatically restore service after momentary outage.
- Single Phase Re-closing.
- Remote sensing-voltage, current and power factor.
- Capability to be programmed into a Remote Fault indicator, Fault isolation and Service restoration schemes.
- Reduced MAIFI.
- Increased ability to sense fault current.
- Ability to be used as a switch with protection function deactivated.

The following are the disadvantages:

- No visible isolation. PowerStream installs additional switches to meet lines operational requirements.
- Time current coordination required with upstream protection.

Average Switch costs incurred in 2014, including installation, are seen below:

- S&C ScadaMate = $78,496
- G&W Recloser = $70,242

Actual Engineering costs have shown that the Recloser can be installed for approximately $8000 less than the Scadamate. Additionally, the Recloser has added advantages with fault interruption and its ability to be used in fault Restoration and Isolation schemes.

Based on financial savings and the additional functional advantages that the Recloser offers it is recommended that PowerStream look at installing Reclosers instead of N.C Scada-mate switches in the future. If the fault interrupting function is not required in an installation, the trip function of the recloser can be deactivated so that it functions as a switch.

Automatic Pad Mounted Switchgear

These devices exist in Markham, Richmond Hill and Vaughan service territories. They can be divided into types: S&C PMH and S&C Vista and G&W PVI. The advantages of these are:

- Remote control underground distribution system.
- Automatically interrupt and isolate fault in underground distribution system.

Of the 29 Underground RTU Devices located in Markham, Richmond Hill and Vaughan, 8 are level 2 DA ready as per the following list:

| Location ID | L2 Automation Device |
|---|---|
| R1SC54 | PVI-9/SEL451 |
| R1SP1006 | PPI-10/SELRTAC |
| R1SP1007 | PPI-10/SELRTAC |
| R8SC77 | PMH-10/SEL487 |
| R8SC146 | PMH-11/SEL487 |
| R15SC59 | PMH-9/SELAXION |
| R16SC36 | PMH-9/SELAXION |
| R16SC43 | PMH-9/SEL487 |

**Table 14: L2 DA Ready Switchgear**

PowerStream is currently in the process of creating a standard for the use of Solid Dielectric Switchgear made by G&W and T&B. Vendor drawings have been approved and installation of the first unit is expected to be completed by the end of 2015.

# 8.0 DAS Implementation at PowerStream

Two separate management committees have been formed to manage the evolution and implementation of Distribution Automation at PowerStream.

1. DA Steering Committee:

    - Responsible for providing overall direction and guidance with Distribution Automation development.
    - Members:
        - SVP Operations & Construction (Chair)
        - EVP Asset Management
        - SVP Engineering Services
        - VP Operations
        - Director of Asset Planning

2. DA Technical Committee:

    - Responsible for:
        - Assessing and approving new technologies and schemes
        - Assessing the progress and success of the plan
        - Report to DA Steering Committee
    - Members:
        - Director Lines (Chair)
        - Manager Station Design & Construction
        - Manager System Control
        - Manager System Planning
        - Manager P&C
        - Manager Engineering Design
        - Engineer Reliability
        - P&C Technologist

Although the DA Strategy and Technical committees are relatively new, there is general consensus from the team members that this structure will be an effective method moving forward to guide the focus, progress and reporting of the many cross-department activities and ideas related to distribution automation.

Distribution Automation Strategy [5]

In December 2013, the DA Steering Committee authored a report titled 'PowerStream Distribution Automation Strategy' which outlined a 10 year vision for DA between 2013 and 2023. The main components and milestones of the strategy are listed below:

1. PowerStream Distribution Automation - **2013**
   - Interconnected feeders at 27.6 or 44 kV
   - 2.5 remote controlled switching points per feeder (70% penetration)
   - Level 1 DA – all points controlled via SCADA
   - No DA on MS distribution circuits or within commercial/residential subdivisions
   - SCADA Controlled MicroFit Generator (200 kW or higher)

2. PowerStream Distribution Automation - **2018**
   - Interconnected feeders at 27.6 or 44 kV - 2.5 remote controlled switching points per feeder (100% penetration)
   - Level 1 DA - 75% of the system
   - Level 2 DA – combination of FDIR and AFR (peer to peer) on 25% of system
   - Line Sensing communicating to SCADA deployed in commercial subdivisions (50%)
   - Limited/Targeted Level 1 DA on MS distribution circuits

3. PowerStream Distribution Automation - **2023**
   - SCADA Migrated to Advanced Distribution Management System (ADMS)
   - Interconnected feeders at 27.6 or 44 kV - 2.5 remote controlled switching points per feeder (100% penetration)
   - Level 2 DA – combination of FDIR/AFR (peer to peer) on 100% of system, including MS distribution
   - Line Sensing communicating to SCADA deployed in commercial and residential subdivisions (100%)

RTU Device installation 2015-2018

Table 11 and Table 12 in Section 6.4 illustrate quantities of RTU switches required for each feeder, based on current system configuration and the assumption that the load is evenly distributed along the entire length of the feeder. Although the system configuration is changing dynamically and the load is not always evenly distributed, the principles implied in Table 11 and Table 12 still apply.

Tables 11 and 12 indicate that 106 RTU switches are required for level 1 Automation as distributed below:

- 46 N.C. RTU switches
- 60 N.O. RTU switches

The required 106 RTU switches are recommended to be installed in the following N.C. and N.O. distribution:

46 N.C RTU switches/Reclosers are proposed to be installed on selected feeders for years 2015 to 2018 according following criteria:

- Requirement of customers per segment and expected reliability improvement as shown in Table 11
- Requirements from Operations - Control Room

60 N.O RTU switches or tie-reclosers are proposed to be installed on selected feeders for years 2015 to 2018 according to the following criteria:

- Feeder loading per segment shall be less than 150A
- Requirements from Operations - Control Room
- Possibility to connect to other feeders

By installing approximately 26.5 DA switches per year starting in 2015, PowerStream will be able to achieve its interim DA Strategy targets of 2.5 remote controlled switches on interconnected feeders at 27.6 or 44kV by 2018.

Distribution Automation Capital Plan 2015-2020

PowerStream has been installing, on average, 23 switches per year under the Distribution Automation Capital plan to sectionalize and build ties between feeders to meet the level 1 requirement of DAS system as outlined in the report.

The six year plan for level 1 Distribution Automation Switch/Recloser installation is listed below:

| Technology | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| DA Switch | $ | $1,850,276 | $1,530,249 | $2,080,457 | $2,283,805 | $2,354,895 | $2,354,895 | $12,454,577 |
| | Units | 20 | 20 | 23 | 23 | 23 | 23 | 132 |

**Table 15: DA Switch 6 year investment**

In addition to level 1 Automation, PowerStream has initiated level 2 DA projects such as Automatic Feeder Restoration schemes in Vaughan and Markham, an FDIR scheme in Richmond Hill, and an Intelliteam scheme in Markham. On average, about 5 new reclosers are installed per year for these programs.

The six year plan for level 2 Automation focuses primarily on Automatic Feeder Restoration, as listed below:

| **Technology** | | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
|---|---|---|---|---|---|---|---|---|
| AFR | $ | $400,000 | $400,000 | $400,000 | $400,000 | $400,000 | $400,000 | $2,400,000 |
| | Reclosers | 5 | 5 | 5 | 5 | 5 | 5 | 30 |

**Table 16: AFR 6 year investment**

From the above capital budget plans, it can be seen that the years 2015- 2018 will include the installation of 86 RTU switches under Distribution Automation and approximately 20 RTU switches under Automatic Feeder Restoration. Therefore, the installation of the required 106 DA switches, as outlined by the report, will be achieved by 2018. In addition, this plan will also allow PowerStream to achieve its interim DA Strategy targets of 2.5 remote controlled switches on 27.6/44kV feeders by 2018.

Moving beyond 2018, the capital plan for Distribution Automation and Automatic Feeder Restoration will focus on MS distribution feeders in order to meet the DA Strategy targets envisioned for the end state of DA in 2023.

In 2015, it is recommended that the DA Technical Committee begin to monitor the existing Level 2 DA pilot projects in an effort to evaluate their performance. It is expected that following the evaluation, a good understanding of each schemes value to PowerStream can be captured and future expansion efforts can be focused using the most favorable technology.

# 9.0 Conclusions & Recommendations

A complete Distribution Automation System (DAS) remotely monitors the distribution system, facilitates supervisory control of devices and provides decision support tools to improve the system performance. Distribution Automation System allows utilities to implement flexible control of distribution systems, which enhances the efficiency, reliability, and quality of electric service. Distribution automation can play a key role in improving PowerStream reliability, establishing itself as a leader in smart grid technology, and supporting the goal of lowering overall SAIDI below 60 minutes. An effective Distribution Automation strategy and implementation plan is required to achieve these objectives.

It is recommended that the Distribution Automation Committees continue to oversee all DA Strategy and Technical activities moving forward.

It is recommended that PowerStream continue to install Automated Devices to meet the DA Strategy requirements by 2023.

In order to prepare for future Level 2 automation it is recommended that PowerStream install Reclosers instead of Scada-Mate switches.

It is proposed that the DA Technical Committee monitor Level 2 DA pilot projects in 2015 to decide which scheme offers the most value to PowerStream, in order to determine which technology should be focused on for large scale expansion.

It is recommended that the emerging DA products continue to be evaluated and compared to select the next generation of reclosers and automated switchgear.

**References:**

[1] "PowerStream Distribution Automation Report" 2007

[2] "Distribution Automation-How much?" Charlie Williams of S&C, T&D Automation

[3] "Electrical Power Distribution, Automation, Protection and Control" James Momoh

[4] "PowerStream Distribution Automation Report" 2012

[5] "PowerStream Distribution Automation Strategy" 2013

# Appendix A: PowerStream Loading Information (2014)

**PowerStream East Coincident Peaks - 2014**

**(Peak Day of the Month)**

| | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Day | 7 | 27 | 3 | 4 | 27 | 30 | 22 | 26 | 5 | 3 | 18 | |
| Time of Peak | | 19:00 | 19:00 | 20:00 | 11:00 | 16:00 | 14:00 | 17:00 | 16:00 | 16:00 | 13:00 | 18:00 | |
| System Peak (MW) Excl Aurora and Barrie | 1482 | 1055 | 996 | 984 | 896 | 1095 | 1150 | 1255 | 1268 | 1307 | 932 | 988 | |
| System Peak (MW) Incl Aurora and Barrie | 2022 | 1404 | 1328 | 1312 | 1166 | 1411 | 1502 | 1639 | 1652 | 1677 | 1188 | 1314 | |
| Import at 28kV Peak (MW) | 835 | 513 | 509 | 501 | 433 | 518 | 585 | 644 | 630 | 625 | 449 | 527 | |
| Markham Coincident Peak | | 374 | 348 | 345 | 298 | 354 | 401 | 419 | 421 | 437 | 332 | 336 | |

**27.6 kV - T.S. Station/Feeder Loading**

| Station/Feeders | Rating/Monthly Load | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Buttonville (MW) plus part 12M1 and 12M2 | 100 | 31 | 42 | 43 | 32 | 41 | 55 | 54 | 50 | 53 | 30 | 41 | |
| 12M3 | 600 | 256 | 89 | 87 | 65 | 148 | 205 | 209 | 186 | 205 | 106 | 152 | |
| 12M4 | 600 | 90 | 82 | 83 | 59 | 80 | 115 | 366 | 363 | 376 | 175 | 205 | |
| 12M9 | 424 | 174 | 120 | 119 | 114 | 144 | 155 | 164 | 165 | 163 | 115 | 116 | |
| 12M10 | 424 | 0 | 132 | 139 | 23 | 50 | 181 | 172 | 168 | 175 | 113 | 123 | |
| 12M11 | 424 | 0 | 0 | 0 | 0 | 0 | 9 | 9 | 8 | 8 | 7 | 11 | |
| 12M12 | 600 | 70 | 409 | 428 | 363 | 445 | 518 | 105 | 92 | 102 | 84 | 155 | |
| Lazenby TS - RHTS#2 (MW) | 40 | 20 | 18 | 13 | 10 | 15 | 18 | 8 | 16 | 16 | 10 | 12 | |
| 36M7 | 589 | 299 | 249 | 146 | 108 | 126 | 145 | 0 | 165 | 155 | 90 | 135 | |
| 36M8 | 589 | 149 | 139 | 139 | 118 | 207 | 255 | 185 | 189 | 193 | 131 | 137 | |
| Leslie (MW) | 45 | 21 | 19 | 20 | 17 | 21 | 24 | 35 | 27 | 29 | 19 | 22 | |
| 51M1 | 600 | 196 | 172 | 180 | 159 | 0 | 0 | 156 | 63 | 68 | 34 | 45 | |
| 51M2 | 600 | 216 | 190 | 196 | 151 | 188 | 229 | 224 | 197 | 222 | 132 | 170 | |
| 51M31 | 600 | 24 | 23 | 24 | 28 | 268 | 283 | 362 | 320 | 334 | 243 | 247 | |
| Agincourt (MW) | 25 | 5 | 9 | 8 | 4 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | |
| 63M1 | 600 | 111 | 190 | 179 | 88 | 101 | 103 | 97 | 77 | 77 | 92 | 76 | |
| 63M2 | 400 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Markham TS#1 - J.V.Fry (MW) | 81 | 68 | 55 | 52 | 63 | 66 | 55 | 39 | 73 | 66 | 56 | 55 | |
| 22M1 | 533 | 158 | 139 | 143 | 101 | 125 | 85 | 154 | 145 | 155 | 72 | 147 | |
| 22M2 | 488 | 52 | 46 | 47 | 65 | 66 | 68 | 71 | 84 | 74 | 63 | 53 | |
| 22M3 | 488 | 20 | 20 | 18 | 27 | 26 | 26 | 24 | 28 | 24 | 28 | 19 | |
| 22M4 | 537 | 87 | 89 | 81 | 107 | 110 | 54 | 96 | 128 | 122 | 109 | 84 | |
| 22M5 | 488 | 240 | 225 | 214 | 289 | 299 | 255 | 288 | 361 | 350 | 285 | 247 | |
| 22M6 | 488 | 195 | 122 | 118 | 234 | 248 | 208 | 253 | 267 | 261 | 237 | 223 | |
| 22M7 | 574 | 403 | 229 | 212 | 220 | 257 | 237 | 0 | 287 | 281 | 244 | 230 | |
| 22M8 | 574 | 286 | 290 | 280 | 301 | 322 | 302 | 0 | 320 | 207 | 185 | 172 | |
| Markham TS#2 - A.M.Walker (MW) | 101 | 63 | 66 | 68 | 40 | 64 | 89 | 84 | 76 | 75 | 49 | 34 | |
| 24M1 | 532 | 310 | 189 | 189 | 0 | 235 | 197 | 225 | 207 | 54 | 103 | 10 | |
| 24M2 | 540 | 0 | 63 | 66 | 181 | 202 | 248 | 93 | 90 | 96 | 146 | 0 | |
| 24M3 | 540 | 354 | 256 | 263 | 0 | 83 | 134 | 155 | 0 | 161 | 165 | 292 | |
| 24M4 | 532 | 0 | 222 | 229 | 224 | 214 | 272 | 303 | 420 | 309 | 130 | 0 | |
| 24M5 | 511 | 332 | 316 | 322 | 0 | 238 | 331 | 436 | 343 | 369 | 165 | 231 | |
| 24M6 | 532 | 0 | 121 | 124 | 309 | 114 | 390 | 239 | 227 | 243 | 129 | 0 | |
| 24M7 | 511 | 279 | 170 | 181 | 0 | 154 | 198 | 218 | 203 | 222 | 100 | 162 | |
| 24M8 | 532 | 0 | 8 | 9 | 102 | 88 | 100 | 92 | 104 | 108 | 68 | 0 | |
| Markham TS#3 - D.H.Cockburn T1&T2 (MW) | 101 | 33 | 26 | 25 | 22 | 21 | 23 | 52 | 54 | 58 | 18 | 63 | |
| 26M1 | 421 | 187 | 183 | 178 | 154 | 216 | 249 | 236 | 249 | 257 | 185 | 186 | |
| 26M2 | 421 | 0 | 0 | 0 | 0 | 0 | 0 | 371 | 397 | 353 | 0 | 285 | |
| 26M3 | 421 | 266 | 136 | 133 | 99 | 0 | 0 | 175 | 168 | 265 | 0 | 187 | |
| 26M4 | 421 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 26M5 | 421 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 116 | |
| 26M6 | 421 | 27 | 32 | 31 | 30 | 39 | 41 | 39 | 40 | 40 | 38 | 39 | |
| 26M7 | 421 | 0 | 0 | 0 | 0 | 0 | 0 | 66 | 65 | 70 | 0 | 51 | |
| 26M8 | 421 | 192 | 182 | 174 | 161 | 195 | 208 | 213 | 219 | 225 | 153 | 397 | |
| Markham TS#3 - D.H.Cockburn T3&T4 (MW) | 101 | 72 | 45 | 44 | 45 | 60 | 60 | 85 | 62 | 78 | 101 | 56 | |
| 26M11 | 607 | 204 | 183 | 184 | 125 | 180 | 230 | 158 | 153 | 327 | 75 | 273 | |
| 26M12 | 551 | 0 | 0 | 0 | 106 | 126 | 172 | 457 | 173 | 190 | 98 | 133 | |
| 26M13 | 645 | 309 | 226 | 226 | 178 | 251 | 174 | 277 | 263 | 280 | 162 | 71 | |
| 26M14 | 645 | 412 | 203 | 206 | 132 | 205 | 272 | 299 | 276 | 301 | 312 | 192 | |
| 26M15 | 645 | 262 | 252 | 234 | 256 | 273 | 217 | 231 | 249 | 253 | 269 | 185 | |
| 26M16 | 645 | 75 | 88 | 85 | 92 | 116 | 110 | 109 | 122 | 242 | 120 | 206 | |
| 26M17 | 645 | 34 | 32 | 33 | 26 | 26 | 28 | 27 | 29 | 30 | 29 | 38 | |
| 26M18 | 645 | 214 | 42 | 48 | 31 | 109 | 81 | 295 | 89 | 77 | 131 | 69 | |
| Markham TS#4 - R.M. Fabro (MW) | 153 | 59 | 55 | 56 | 56 | 62 | 70 | 56 | 57 | 57 | 46 | 44 | |
| 10M1 | 622 | 105 | 101 | 86 | 87 | 123 | 118 | 114 | 139 | 140 | 108 | 98 | |
| 10M2 | 622 | 333 | 190 | 195 | 203 | 213 | 264 | 42 | 54 | 90 | 81 | 29 | |
| 10M3 | 622 | 33 | 34 | 31 | 39 | 36 | 76 | 34 | 42 | 40 | 35 | 32 | |
| 10M4 | 622 | 229 | 209 | 203 | 190 | 158 | 279 | 234 | 210 | 213 | 117 | 119 | |
| 10M5 | 622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 10M6 | 622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 10M7 | 622 | 0 | 0 | 88 | 92 | 104 | 73 | 86 | 74 | 74 | 61 | 48 | |
| 10M8 | 622 | 114 | 121 | 112 | 137 | 165 | 171 | 155 | 164 | 167 | 147 | 124 | |
| 10M9 | 622 | 244 | 320 | 307 | 248 | 341 | 335 | 347 | 348 | 313 | 257 | 294 | |
| 10M10 | 622 | 161 | 165 | 150 | 186 | 209 | 219 | 213 | 221 | 221 | 186 | 169 | |
| 10M11 | 622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 10M12 | 622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| MDE Generator (Warden and Birchmount) | 12.6 | 0.0 | 10.3 | 10.3 | 6.3 | 0.1 | 2.0 | 1.0 | 2.0 | 2.0 | 0.0 | 2.5 | |
| MDE Generator (Bur Oak) | 4 | 0.0 | 3.9 | 3.9 | 3.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.9 | |

**PowerStream West Coincident Peaks - 2014**

**(Peak Day of the Month)**

| | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Day | 7 | 27 | 3 | 4 | 27 | 30 | 22 | 26 | 5 | 3 | 18 | |
| Time of Peak | | 19:00 | 19:00 | 20:00 | 11:00 | 16:00 | 14:00 | 17:00 | 16:00 | 16:00 | 13:00 | 18:00 | |
| System Peak (MW) Excl Aurora and Barrie | 1482 | 1055 | 996 | 984 | 896 | 1095 | 1150 | 1255 | 1268 | 1307 | 932 | 988 | |
| System Peak (MW) Incl Aurora and Barrie | 2022 | 1404 | 1328 | 1312 | 1166 | 1411 | 1502 | 1639 | 1652 | 1677 | 1188 | 1314 | |
| Import at 28kV Peak (MW) | 835 | 513 | 509 | 501 | 433 | 518 | 585 | 644 | 630 | 625 | 449 | 527 | |
| Vaughan Coincident Peak | | 452 | 437 | 430 | 437 | 532 | 504 | 580 | 598 | 602 | 444 | 458 | |

**27.6 kV - T.S. Station/Feeder Loading**

| Station/Feeders | Rating/Monthly Load | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Vaughan MTS#1 T1&T2 (MW) | 153 | 125 | 87 | 86 | 123 | 111 | 101 | 126 | 127 | 130 | 88 | 106 | |
| 20M1 | 738 | 209 | 225 | 220 | 233 | 258 | 188 | 257 | 271 | 251 | 235 | 220 | |
| 20M3 | 618 | 252 | 8 | 9 | 233 | 281 | 332 | 520 | 505 | 536 | 359 | 388 | |
| 20M4 | 618 | 0 | 12 | 13 | 194 | 281 | 309 | 333 | 324 | 356 | 197 | 228 | |
| 20M5 | 778 | 165 | 157 | 152 | 163 | 7 | 8 | 10 | 11 | 10 | 5 | 5 | |
| 20M6 | 778 | 153 | 374 | 136 | 101 | 46 | 51 | 58 | 54 | 62 | 30 | 357 | |
| 20M7 | 550 | 236 | 224 | 215 | 269 | 0 | 10 | 9 | 11 | 10 | 9 | 48 | |
| 20M8 | 550 | 244 | 0 | 238 | 294 | 0 | 0 | 0 | 0 | 0 | 0 | 79 | |
| 20M9 | 618 | 247 | 0 | 0 | 275 | 306 | 233 | 287 | 345 | 319 | 280 | 247 | |
| 20M10 | 618 | 242 | 0 | 0 | 274 | 459 | 337 | 378 | 366 | 364 | 274 | 260 | |
| 20M11 | 550 | 347 | 396 | 394 | 277 | 378 | 393 | 379 | 316 | 353 | 83 | 79 | |
| 20M12 | 550 | 396 | 314 | 320 | 129 | 208 | 222 | 351 | 362 | 391 | 227 | 153 | |
| 20M14 | 735 | 155 | 150 | 143 | 200 | 205 | 116 | 179 | 219 | 197 | 203 | 181 | |
| Vaughan MTS#1 T3&T4 (MW) | 153 | 100 | 63 | 63 | 39 | 94 | 79 | 92 | 97 | 97 | 65 | 119 | |
| 20M15 | 572 | 147 | 151 | 148 | 119 | 0 | 53 | 151 | 130 | 114 | 134 | 160 | |
| 20M16 | 572 | 186 | 289 | 272 | 182 | 2 | 252 | 322 | 381 | 352 | 348 | 221 | |
| 20M17 | 572 | 292 | 1 | 1 | 1 | 210 | 1 | 1 | 1 | 1 | 1 | 299 | |
| 20M18 | 572 | 439 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 340 | |
| 20M19 | 572 | 248 | 1 | 1 | 92 | 409 | 1 | 1 | 1 | 1 | 1 | 271 | |
| 20M20 | 572 | 261 | 7 | 7 | 68 | 243 | 2 | 2 | 1 | 1 | 1 | 387 | |
| 20M21 | 572 | 436 | 460 | 462 | 210 | 315 | 521 | 511 | 483 | 523 | 276 | 549 | |
| 20M22 | 572 | 164 | 456 | 471 | 182 | 219 | 254 | 266 | 262 | 269 | 172 | 89 | |
| 20M23 | 572 | 0 | 0 | 0 | 0 | 321 | 280 | 383 | 439 | 444 | 320 | 0 | |
| 20M24 | 572 | 0 | 0 | 0 | 0 | 379 | 379 | 419 | 452 | 446 | 191 | 286 | |
| Vaughan MTS#2 (MW) | 153 | 96 | 105 | 101 | 104 | 120 | 110 | 123 | 144 | 145 | 112 | 73 | |
| 21M1 | 600 | 29 | 16 | 15 | 34 | 37 | 34 | 17 | 15 | 11 | 34 | 37 | |
| 21M2 | 600 | 194 | 190 | 188 | 204 | 210 | 122 | 210 | 218 | 208 | 186 | 181 | |
| 21M3 | 600 | 431 | 388 | 395 | 397 | 529 | 317 | 415 | 528 | 486 | 387 | 463 | |
| 21M4 | 428 | 267 | 222 | 209 | 334 | 331 | 405 | 354 | 332 | 396 | 134 | 256 | |
| 21M5 | 428 | 128 | 234 | 224 | 216 | 153 | 243 | 152 | 274 | 235 | 214 | 0 | |
| 21M6 | 428 | 248 | 254 | 231 | 262 | 330 | 278 | 361 | 378 | 304 | 289 | 0 | |
| 21M7 | 428 | 144 | 140 | 128 | 0 | 195 | 123 | 172 | 180 | 168 | 176 | 145 | |
| 21M8 | 428 | 164 | 155 | 159 | 136 | 177 | 224 | 241 | 389 | 416 | 222 | 236 | |
| 21M9 | 428 | 176 | 250 | 236 | 366 | 381 | 259 | 337 | 422 | 375 | 347 | 0 | |
| 21M10 | 428 | 147 | 151 | 138 | 154 | 203 | 175 | 205 | 208 | 315 | 212 | 168 | |
| 21M11 | 428 | 82 | 245 | 228 | 121 | 99 | 213 | 281 | 270 | 293 | 248 | 42 | |
| 21M12 | 600 | 24 | 32 | 32 | 40 | 32 | 31 | 16 | 22 | 23 | 34 | 23 | |
| Vaughan MTS#3 (MW) | 153 | 68 | 114 | 116 | 96 | 113 | 110 | 125 | 121 | 119 | 78 | 70 | |
| 5122M1 | 471 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5122M2 | 471 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5122M3 | 471 | 136 | 156 | 162 | 174 | 196 | 26 | 61 | 199 | 177 | 185 | 173 | |
| 5122M4 | 471 | 2 | 144 | 149 | 114 | 150 | 153 | 154 | 137 | 149 | 77 | 97 | |
| 5122M5 | 471 | 156 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5122M6 | 471 | 194 | 304 | 310 | 201 | 227 | 193 | 227 | 240 | 231 | 212 | 192 | |
| 5122M7 | 471 | 221 | 325 | 311 | 372 | 257 | 244 | 325 | 350 | 356 | 270 | 40 | |
| 5122M8 | 471 | 39 | 328 | 327 | 352 | 380 | 225 | 324 | 369 | 359 | 311 | 223 | |
| 5122M9 | 471 | 204 | 443 | 479 | 326 | 474 | 376 | 438 | 350 | 386 | 147 | 392 | |
| 5122M10 | 471 | 277 | 250 | 257 | 171 | 280 | 372 | 470 | 305 | 354 | 127 | 195 | |
| 5122M11 | 471 | 75 | 240 | 246 | 172 | 275 | 421 | 453 | 422 | 437 | 225 | 63 | |
| 5122M12 | 471 | 100 | 179 | 178 | 136 | 218 | 231 | 268 | 265 | 146 | 128 | 78 | |
| 5122M13 | 471 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5122M14 | 471 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Woodbridge | 60 | 45 | 41 | 37 | 44 | 49 | 50 | 59 | 51 | 51 | 43 | 42 | |
| D6M2 | 500 | 317 | 233 | 213 | 231 | 277 | 283 | 344 | 244 | 263 | 145 | 184 | |
| D6M3 | 500 | 180 | 187 | 179 | 221 | 229 | 157 | 194 | 208 | 196 | 212 | 203 | |
| D6M5 | 500 | 170 | 182 | 145 | 218 | 265 | 246 | 259 | 294 | 258 | 254 | 218 | |
| D6M6 | 500 | 253 | 242 | 220 | 245 | 280 | 391 | 456 | 331 | 355 | 285 | 263 | |
| Fairchild | 45 | 9 | 19 | 18 | 15 | 20 | 24 | 18 | 20 | 22 | 23 | 27 | |
| 80M12 | 500 | 47 | 246 | 242 | 208 | 297 | 341 | 341 | 374 | 405 | 432 | 425 | |
| 80M25 | 500 | 144 | 139 | 132 | 107 | 137 | 168 | 45 | 46 | 50 | 22 | 121 | |
| 80M7 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 | 11 | |
| Finch | 30 | 9 | 9 | 9 | 10 | 11 | 10 | 16 | 18 | 17 | 25 | 11 | |
| 55M11 | 500 | 130 | 124 | 120 | 166 | 171 | 148 | 162 | 188 | 178 | 169 | 154 | |
| 55M12 | 500 | 66 | 62 | 64 | 41 | 70 | 84 | 201 | 224 | 208 | 401 | 74 | |
| Kleinberg | 30 | 0.0 | 0.0 | 0.0 | 6.4 | 14.2 | 19.1 | 20.5 | 20.5 | 21.9 | 10.5 | 9.7 | |
| 45M3 | 500 | 0 | 0 | 0 | 37 | 31 | 33 | 31 | 34 | 33 | 29 | 38 | |
| 45M4 | 500 | 0 | 0 | 0 | 93 | 253 | 360 | 392 | 386 | 420 | 179 | 158 | |
| Sobey's Generator | 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |

## PowerStream Central Coincident Peaks - 2014

**(Peak Day of the Month)**

| | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Day | 7 | 27 | 3 | 4 | 27 | 30 | 22 | 26 | 5 | 3 | 18 | |
| Time of Peak | | 19:00 | 19:00 | 20:00 | 11:00 | 16:00 | 14:00 | 17:00 | 16:00 | 16:00 | 13:00 | 18:00 | |
| System Peak (MW) Excl Aurora and Barrie | 1482 | 1055 | 996 | 984 | 896 | 1095 | 1150 | 1255 | 1268 | 1307 | 932 | 988 | |
| System Peak (MW) Incl Aurora and Barrie | 2022 | 1404 | 1328 | 1312 | 1166 | 1411 | 1502 | 1639 | 1652 | 1677 | 1188 | 1314 | |
| Import at 28kV Peak (MW) | 835 | 513 | 509 | 501 | 433 | 518 | 585 | 644 | 630 | 625 | 449 | 527 | |
| Richmond Hill Coincident Peak | | 229 | 210 | 210 | 161 | 208 | 245 | 257 | 249 | 268 | 156 | 195 | |

## 27.6 kV - T.S. Station/Feeder Loading

| Station/Feeders | Rating/Monthly Load | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Buttonville (MW) | 50 | 43 | 39 | 38 | 36 | 41 | 45 | 55 | 56 | 58 | 39 | 46 | |
| 12M1 (Amps) | 600 | 9 | 61 | 55 | 58 | 73 | 84 | 159 | 169 | 176 | 126 | 111 | |
| 12M2 (Amps) - Mrkm and RH | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 12M5 (Amps) | 600 | 175 | 212 | 190 | 235 | 263 | 249 | 259 | 300 | 289 | 231 | 308 | |
| 12M6 (Amps) | 600 | 105 | 0 | 0 | 0 | 82 | 107 | 117 | 107 | 118 | 52 | 91 | |
| 12M7 (Amps) | 600 | 345 | 285 | 285 | 234 | 350 | 377 | 287 | 293 | 314 | 185 | 214 | |
| 12M8 (Amps) | 600 | 269 | 261 | 267 | 225 | 94 | 129 | 321 | 297 | 314 | 212 | 232 | |
| Richmond Hill MTS#1 (MW) | 153 | 106 | 115 | 115 | 90 | 111 | 136 | 141 | 136 | 142 | 47 | 97 | |
| 27M1 | 413 | 235 | 265 | 280 | 139 | 191 | 259 | 272 | 256 | 286 | 125 | 183 | |
| 27M2 | 413 | 0 | 159 | 162 | 119 | 161 | 200 | 213 | 197 | 210 | 58 | 146 | |
| 27M3 | 413 | 135 | 121 | 123 | 96 | 110 | 78 | 81 | 82 | 86 | 55 | 64 | |
| 27M4 | 413 | 239 | 226 | 235 | 186 | 253 | 282 | 282 | 272 | 298 | 171 | 196 | |
| 27M5 | 413 | 258 | 328 | 342 | 270 | 242 | 361 | 377 | 336 | 273 | 132 | 189 | |
| 27M6 | 413 | 300 | 118 | 116 | 90 | 109 | 305 | 306 | 294 | 309 | 247 | 224 | |
| 27M7 | 413 | 239 | 225 | 237 | 208 | 314 | 231 | 250 | 232 | 271 | 102 | 169 | |
| 27M8 | 413 | 25 | 201 | 220 | 129 | 184 | 267 | 299 | 268 | 300 | 115 | 194 | |
| 27M9 | 577 | 275 | 219 | 215 | 220 | 265 | 319 | 315 | 332 | 339 | 251 | 229 | |
| 27M10 | 487 | 139 | 130 | 136 | 94 | 144 | 180 | 182 | 170 | 185 | 100 | 119 | |
| 27M11 | 577 | 193 | 198 | 186 | 199 | 243 | 246 | 258 | 275 | 276 | 233 | 99 | |
| 27M12 | 487 | 141 | 121 | 127 | 97 | 129 | 169 | 174 | 168 | 179 | 89 | 120 | |
| Richmond Hill MTS#2 (MW) | 101 | 100 | 73 | 69 | 45 | 71 | 81 | 69 | 74 | 84 | 81 | 65 | |
| 36M1 (Vaughan/Richmond Hill) | 594 | 424 | 296 | 307 | 220 | 339 | 421 | 503 | 456 | 524 | 223 | 282 | |
| 36M2 | 594 | 55 | 132 | 133 | 99 | 137 | 172 | 180 | 167 | 179 | 96 | 121 | |
| 36M3 | 753 | 568 | 187 | 198 | 134 | 216 | 259 | 290 | 259 | 293 | 131 | 301 | |
| 36M4 (Vaughan) | 753 | 273 | 231 | 232 | 7 | 12 | 13 | 12 | 13 | 13 | 10 | 9 | |
| 36M5 | 594 | 158 | 140 | 146 | 104 | 339 | 338 | 151 | 146 | 161 | 103 | 136 | |
| 36M6 | 594 | 152 | 144 | 142 | 138 | 150 | 155 | 164 | 195 | 297 | 227 | 223 | |
| 36M7 (Markham) | 589 | 299 | 249 | 146 | 108 | 126 | 145 | 0 | 165 | 155 | 90 | 135 | |
| 36M8 (Markham) | 589 | 149 | 139 | 139 | 118 | 207 | 255 | 185 | 189 | 193 | 131 | 137 | |

## PowerStream Aurora Peaks - 2014

**(Peak Day of the Month)**

| | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Day | 7 | 27 | 3 | 4 | 27 | 30 | 22 | 26 | 5 | 3 | 18 | |
| Time of Peak | | 19:00 | 19:00 | 20:00 | 11:00 | 16:00 | 14:00 | 17:00 | 16:00 | 16:00 | 13:00 | 18:00 | |
| System Peak (MW) Excl Aurora and Barrie | 1482 | 1055 | 996 | 984 | 896 | 1095 | 1150 | 1255 | 1268 | 1307 | 932 | 988 | |
| System Peak (MW) Incl Aurora and Barrie | 2022 | 1404 | 1328 | 1312 | 1166 | 1411 | 1502 | 1639 | 1652 | 1677 | 1188 | 1314 | |
| Import at 28kV Peak (MW) | 835 | 513 | 509 | 501 | 433 | 518 | 585 | 644 | 630 | 625 | 449 | 527 | |
| Aurora Coincident Peak | | 74 | 68 | 68 | 56 | 67 | 74 | 81 | 81 | 84 | 52 | 67 | |

## 44kV and 13.8kV Station/Feeder Loading

| Station/Feeders | Rating/Monthly Load | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Armitage (MW) | 90 | 73 | 68 | 68 | 56 | 67 | 73 | 80 | 81 | 83 | 52 | 66 | |
| 41M11 (Amps) | 600 | 46 | 46 | 45 | 50 | 199 | 73 | 66 | 74 | 75 | 60 | 309 | |
| 41M14 (Amps) | 600 | 270 | 253 | 255 | 214 | 323 | 258 | 325 | 316 | 320 | 224 | 0 | |
| 41M41 (Amps) | 600 | 217 | 193 | 203 | 149 | 0 | 233 | 272 | 263 | 273 | 137 | 198 | |
| 41M43 (Amps) | 600 | 226 | 212 | 204 | 168 | 190 | 200 | 219 | 232 | 229 | 156 | 184 | |
| 41M44 (Amps) | 600 | 192 | 181 | 180 | 151 | 231 | 243 | 223 | 230 | 240 | 132 | 177 | |
| Aurora MS #1 - T1 | 15 | 6.54 | 6.01 | 5.69 | 3.80 | 5.54 | 6.50 | 6.34 | 6.22 | 5.62 | 4.21 | 5.74 | |
| Aurora MS #1 - T2 | 15 | 5.55 | 5.33 | 5.29 | 5.07 | 5.85 | 5.96 | 6.41 | 7.13 | 6.68 | 4.45 | 5.21 | |
| A-1F1 | 485 | 121 | 111 | 114 | 80 | 104 | 128 | 137 | 78 | 80 | 72 | 108 | |
| A-1F2 | 485 | 253 | 232 | 205 | 119 | 153 | 166 | 179 | 179 | 181 | 114 | 151 | |
| A-1F3 | 485 | 137 | 128 | 129 | 110 | 136 | 196 | 213 | 166 | 165 | 104 | 124 | |
| A-1F4 | 485 | 95 | 94 | 92 | 101 | 108 | 52 | 54 | 131 | 114 | 82 | 94 | |
| Aurora MS #2 - T1 | 15 | 8.51 | 8.13 | 7.57 | 6.74 | 7.29 | 8.60 | 8.62 | 8.90 | 9.70 | 5.62 | 7.94 | |
| A-2F1 | 313 | 158 | 153 | 137 | 113 | 122 | 144 | 138 | 149 | 179 | 77 | 144 | |
| A-2F2 | 315 | 46 | 42 | 37 | 31 | 37 | 49 | 63 | 50 | 52 | 24 | 41 | |
| A-2F3 | 350 | 150 | 145 | 144 | 141 | 166 | 190 | 181 | 196 | 202 | 144 | 150 | |
| Aurora MS #3 - T1 | 15 | 4.73 | 4.13 | 4.21 | 2.72 | 3.13 | 4.21 | 4.53 | 4.63 | 4.24 | 2.85 | 4.14 | |
| Aurora MS #3 - T2 | 15 | 5.94 | 5.06 | 6.13 | 4.89 | 6.81 | 8.68 | 7.60 | 7.04 | 7.49 | 3.04 | 5.07 | |
| A-3F1 | 488 | 118 | 105 | 106 | 69 | 78 | 109 | 117 | 118 | 130 | 54 | 96 | |
| A-3F2 | 488 | 74 | 62 | 64 | 42 | 53 | 70 | 76 | 80 | 52 | 68 | 72 | |
| A-3F3 | 375 | 91 | 79 | 89 | 102 | 128 | 170 | 190 | 170 | 183 | 62 | 114 | |
| A-3F4 | 375 | 148 | 124 | 158 | 106 | 163 | 208 | 138 | 133 | 143 | 63 | 90 | |
| Aurora MS #4 - T1 (44/13.8) | 15 | 5.54 | 5.06 | 4.78 | 2.95 | 2.28 | 2.93 | 7.10 | 6.69 | 7.14 | 3.53 | 5.35 | |
| Aurora MS #4 - T2 (27.6/13.8) | 15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| A-4F1 | 409 | 102 | 89 | 81 | 35 | 59 | 72 | 78 | 74 | 81 | 38 | 52 | |
| A-4F2 | 409 | 96 | 93 | 88 | 71 | 8 | 12 | 105 | 102 | 109 | 63 | 88 | |
| A-4F3 | 473 | 33 | 28 | 30 | 15 | 28 | 42 | 130 | 116 | 125 | 48 | 82 | |
| Aurora MS #5 - T1 | 15 | 5.84 | 4.99 | 5.22 | 3.40 | 5.08 | 6.81 | 7.53 | 7.03 | 7.73 | 3.14 | 4.96 | |
| Aurora MS #5 - T2 | 15 | 3.37 | 3.03 | 3.06 | 2.10 | 2.99 | 3.80 | 4.22 | 3.86 | 4.18 | 1.90 | 3.10 | |
| A-5F1 | 409 | 88 | 73 | 75 | 49 | 76 | 104 | 114 | 107 | 118 | 46 | 76 | |
| A-5F2 | 409 | 152 | 131 | 139 | 88 | 137 | 188 | 207 | 195 | 213 | 82 | 127 | |
| A-5F3 | 409 | 84 | 77 | 79 | 51 | 78 | 101 | 113 | 101 | 111 | 45 | 78 | |
| A-5F4 | 409 | 52 | 45 | 45 | 33 | 46 | 60 | 66 | 62 | 66 | 32 | 49 | |
| Aurora MS #6 - T1 (44/13.8) | 15 | 6.54 | 6.07 | 6.62 | 5.10 | 7.70 | 8.86 | 7.49 | 7.80 | 7.59 | 4.15 | 5.52 | |
| Aurora MS #6 - T2 (27.6/13.8) | 15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| A-6F1 | 396 | 164 | 146 | 150 | 91 | 138 | 178 | 188 | 178 | 191 | 87 | 133 | |
| A-6F2 | 396 | 106 | 103 | 120 | 116 | 197 | 209 | 135 | 155 | 137 | 87 | 93 | |
| Aurora MS #7 - T1 (44/27.6) | 10 | 0.38 | 0.42 | 0.38 | 0.47 | 0.56 | 0.61 | 0.56 | 0.61 | 0.61 | 0.56 | 0.47 | |
| A-7F1 | 400 | 8 | 9 | 8 | 10 | 12 | 13 | 12 | 13 | 13 | 12 | 10 | |
| A-7F2 | 400 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Aurora MS #8 - T1 (44/27.6) | 10 | 2.63 | 2.49 | 2.34 | 2.67 | 3.56 | 4.22 | 3.85 | 4.31 | 4.50 | 3.56 | 3.09 | |
| A-8F1 | 400 | 51 | 51 | 48 | 56 | 75 | 88 | 81 | 91 | 95 | 75 | 65 | |
| A-8F2 | 400 | 5 | 2 | 2 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 1 | |
| Classic Power Generator | 1 | 0.68 | 0.48 | 0.00 | 0.00 | 0.56 | 0.56 | 0.56 | 0.00 | 0.57 | 0.45 | 0.58 | |

## PowerStream Barrie Peaks - 2014

(Peak Day of the Month)

| | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| | Day | 7 | 27 | 3 | 4 | 27 | 30 | 22 | 26 | 5 | 3 | 18 | |
| Time of Peak | | 19:00 | 19:00 | 20:00 | 11:00 | 16:00 | 14:00 | 17:00 | 16:00 | 16:00 | 13:00 | 18:00 | |
| System Peak (MW) Excl Aurora and Barrie | 1482 | 1055 | 996 | 984 | 896 | 1095 | 1150 | 1255 | 1268 | 1307 | 932 | 988 | |
| System Peak (MW) Incl Aurora and Barrie | 2022 | 1404 | 1328 | 1312 | 1166 | 1411 | 1502 | 1639 | 1652 | 1677 | 1188 | 1314 | |
| Import at 28kV Peak (MW) | 835 | 513 | 509 | 501 | 433 | 518 | 585 | 644 | 630 | 625 | 449 | 527 | |
| Barrie Coincident Peak | 450 | 275 | 264 | 259 | 213 | 249 | 279 | 303 | 302 | 287 | 204 | 259 | |

### TS Coincident Peak Loading

| Station/Feeders | Rating/Monthly Load | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Waubaushene TS | 90 | 14.4 | 15.5 | 15.2 | 12.7 | 12.3 | 13.5 | 15.0 | 15.0 | 13.2 | 11.2 | 14.7 | |
| Alliston TS | 10 | 1.4 | 1.2 | 1.3 | 0.8 | 1.0 | 1.4 | 1.6 | 1.4 | 1.5 | 0.7 | 1.2 | |
| Everett TS | 40 | 38.1 | 37.0 | 35.9 | 28.4 | 34.2 | 37.0 | 43.4 | 42.2 | 43.8 | 28.0 | 36.3 | |
| Holland TS | 40 | 30.4 | 29.6 | 29.6 | 25.1 | 29.2 | 30.7 | 35.4 | 35.8 | 36.3 | 23.9 | 29.6 | |
| Midhust TS - T1T2 | 90 | 56.3 | 57.9 | 56.5 | 56.4 | 25.9 | 31.2 | 27.5 | 78.3 | 74.8 | 52.7 | 44.2 | |
| Midhust TS - T3T4 | 90 | 54.4 | 50.4 | 50.6 | 46.0 | 79.4 | 65.3 | 98.6 | 64.8 | 66.1 | 36.6 | 78.0 | |
| Barrie TS | 90 | 80.1 | 72.4 | 70.4 | 44.1 | 66.9 | 100.0 | 81.8 | 64.7 | 51.0 | 50.7 | 55.1 | |

## PowerStream East M.S. Station (8.32 & 13.8 kV) / Feeder Loading - 2014

(Peak Day of the Month)

| Station | Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Feeders | Rating/Monthly Load | | | | | | | | | | | | |
| **Amber M.S. (13.8kV)** | | | | | | | | | | | | | |
| T1 (MW) | 15 | 1.65 | 1.41 | 1.43 | 2.16 | 1.29 | 2.97 | 2.27 | 2.72 | 2.32 | 2.06 | 0.11 | |
| T2 (MW) | 9 | 0.65 | 0.61 | 0.61 | 0.75 | 1.59 | 0 | 0.84 | 0.98 | 0.95 | 0.71 | 2.29 | |
| AMB-F1 | 355 | 73 | 62 | 63 | 95 | 57 | 131 | 100 | 120 | 102 | 91 | 5 | |
| AMB-F2 | 355 | 28 | 27 | 27 | 33 | 70 | 0 | 37 | 43 | 42 | 31 | 101 | |
| AMB-F3 | 355 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| **Baythorn M.S. (8.32kV)** | | | | | | | | | | | | | |
| T1 (MW) | 9 | 0.2 | 0.24 | 0.22 | 0.22 | 0.33 | 0.36 | 0.34 | 0.94 | 0.35 | 0.28 | 1.54 | |
| T2 (MW) | 9 | 2.34 | 2.46 | 2.49 | 1.56 | 1.93 | 2.5 | 2.77 | 2.84 | 2.84 | 1.14 | 0.79 | |
| BAY-F1 | 320 | 16 | 19 | 17 | 18 | 26 | 29 | 27 | 72 | 28 | 22 | 112 | |
| BAY-F2 | 320 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| BAY-F3 | 320 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| BAY-F4 | 320 | 52 | 62 | 65 | 39 | 53 | 67 | 73 | 67 | 73 | 32 | 0 | |
| BAY-F5 | 320 | 81 | 72 | 73 | 47 | 56 | 80 | 80 | 98 | 86 | 32 | 57 | |
| BAY-F6 | 320 | 36 | 43 | 42 | 28 | 36 | 41 | 53 | 47 | 54 | 22 | 0 | |
| **Morgan M.S. (8.32kV)** | | | | | | | | | | | | | |
| T1 (MW) | 4.5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| T2 (MW) | 4.5 | 0.78 | 0.8 | 0.87 | 0.46 | 0.44 | 0.57 | 0.63 | 0 | 0.57 | 0.27 | 0.63 | |
| MOR-F1 | 300 | 95 | 96 | 104 | 30 | 33 | 46 | 50 | 0 | 46 | 20 | 41 | |
| MOR-F2 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| MOR-F3 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| MOR-F4 | 300 | 0 | 0 | 0 | 27 | 23 | 26 | 30 | 0 | 27 | 15 | 37 | |
| **John M.S. (13.8kV)** | | | | | | | | | | | | | |
| T1 (MW) | 9 | 0.84 | 0.65 | 0.7 | 0.26 | 0.34 | 0.45 | 0.5 | 0.34 | 0.34 | 0.14 | 0.2 | |
| T2 (MW) | 12 | 0.75 | 0.6 | 0.64 | 0.41 | 0.52 | 0.7 | 0.7 | 0.64 | 0.65 | 0.3 | 0.41 | |
| JOH-F3 | 400 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| JOH-F4 | 400 | 37 | 29 | 31 | 12 | 15 | 20 | 22 | 15 | 15 | 6 | 9 | |
| JOH-F5 | 355 | 32 | 25 | 27 | 18 | 23 | 31 | 31 | 28 | 29 | 13 | 18 | |
| JOH-F6 | 355 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |

**EP-30**

**Reference: Exhibit 04, Tab 01, Schedule 01, Appendix A16, Distributed Energy Resources ("DER) Integration, Page 2**

**Preamble: "Alectra Utilities may be able to lower the energy costs for the entire customer base by proactively managing DER in such a way that incremental infrastructure cost upgrades to safeguard the grid from DER adoption or power quality issues are mitigated."**
**Considering that this is new technology there is a significant possibility that Alectra may not be able to lower energy costs for its entire customer base.**

**Question:**

a) **When should the OEB conduct a review of actual costs and actual benefits to evaluate the success of Alectra's costs of integrating DERs?**

b) **If such a review finds that costs are greater than benefits should the OEB hold Alectra accountable and disallow all or a portion of the costs?**

**Response:**

a) With respect to the review of actual costs, the DSP includes 2 DER investments – DER Control Platform of $1.6MM and Smart DER Platform of $2.4MM, proposed over the DSP plan term. As provided in Exhibit 2, Tab 1, Schedule 4, Alectra proposes to establish a Capital Investment Variance Account ("CIVA") which will track the variances between the actual and forecast capital over the DSP term. Consistent with this approach, the actual costs for these projects should be reviewed at the end of the DSP plan term. The planned investments will create multiple benefits for Alectra Utilities' distribution system and its customers, including but not limited to: improved distribution system planning to enable system right-sizing and optimal expansion; improved safety, reliability, cyber-security and system performance through effective control, monitoring and optimizing DERs; and enhanced customer value and satisfaction through providing customers with greater energy choices to consume and generate their own electricity while remaining connected to the grid. For detailed discussion on the planned investment benefits, please refer to Section 2.1 Summary of Investment Outcomes and Benefits on page 14-16, Exhibit 04, Tab 01, Schedule 01, Appendix A16 -Distributed Energy Resources ("DER") Integration.

As with any nascent field, Alectra Utilities acknowledges that managing, integrating and optimizing the Distributed Energy Resources ("DERs") connected to its entire network to achieve a grid wide system benefits and customer benefits is a complex undertaking and will take years. Customer adoption rates of DERs will evolve over time, which will impact the type and quantity of DERs on the system. It is only when there is sufficient scale of DERs that they can be effectively monitored, controlled, integrated and optimized, and that the adoption rates will be heterogenous across Alectra's system.

The need and requirement for DER integration may also vary among different areas of Alectra's system; creating a match between needs and resources will take years. As DER adoption continues to rise, Alectra Utilities expects that distributors will need to revise its approach to distribution system planning to maximize the benefits of DERs to the system, while maintaining reliability and reasonable costs for customers. The planned DER Integration investments are required for Alectra Utilities' to build capabilities and learnings to be prepared to plan and build a system that can safely integrate and optimize value from DERs.

b) Alectra Utilities believes that the benefits of implementing the planed DER integration projects will far out weight the cost of the investment in the long run. The benefits of the investment on the planned projects was discussed in detail in Section 2.1 Summary of Investment Outcomes and Benefits on page 14-16, Exhibit 5, Tab 1, Schedule 01, Appendix A16 -Distributed Energy Resources ("DER") Integration.

The risks imposed by increasing DERs penetration on the distribution networks are real and present that utility company like Alectra can't afford to neglect. Alectra will be forced to understand, mitigate and reduce the risks that DERs pose regarding capacity constraints, power quality, and reliability on the distribution grid, and to ready Alectra Utilities' distribution system to accept and support DERs, including electric vehicles, solar PV systems, and battery storage. Ignoring integration of these resources will also lead to economic inefficiencies, as Alectra Utilities would require investment for additional infrastructure to manage the impact of the DERs on the distribution system.

By undertaking these projects today, Alectra Utilities is preparing the distribution system to safely and reliably respond to the expected uptake of DERs with a coordinated architecture that balances the benefits of DERs to their owners, with the costs they potentially pose on all of Alectra Utilities' customer-base.

**EP-31**

**Reference: Exhibit 04, Tab 01, Schedule 01, Appendix A16, Distributed Energy Resources (“DER) Integration, Page 9**

**Preamble: “Potential Risks to Reliability: With increased DER adoption, the effect of these resources presents certain reliability challenges that require careful understanding and measured actions. This leads to a need for further study to better understand the impacts, and how those effects can be included in planning and operation of the distribution system.”**

**Question:**

**a) When should the OEB review the impact of Alectra’s integration of DERs on Alectra’s reliability performance?**

**b) If the OEB finds that reliability has been adversely affected by DER integration, what should the OEB do?**

**Response:**

a) Please refer to Alectra Utilities’ response to EP-30 a).

b) As customer preferences with respect to energy evolve in favour of more choices, greater control and customization, with the rapid technological innovation which is driving down the costs of energy technologies, an increasing level of DER penetration will impact the reliable operation of traditional distribution system. A comprehensive list of potential challenges posed by high penetration of DERs is presented on page 8 to 9 in Exhibit 4, Tab 1, Schedule 1, Appendix A16. However, Alectra Utilities is developing a DER Control Platform and a Smart DER Platform to provide an end-to-end solution to proactively control, monitor, and coordinate DERs, in its service territory. These two projects are intended to ensure that the reliable operation of Alectra Utilities’ distribution system is met despite high penetration of DERs.

**EP-32**

**Reference: Exhibit 04, Tab 01, Schedule 01, Appendix A16, Distributed Energy Resources ("DER) Integration, Page 23**

**Preamble: "Option 2 maximizes the number of DERs connected to the network before power quality and capacity limitations constrain the connection of new DERs - provides greater energy choices for our customers who wish to consume and generate their own electricity while remaining connected to the network.**

**Question:**

**a) Please explain when and how would Alectra assess the "power quality and capacity limitations"?**

**b) What reliability metrics capacity metrics would Alectra use in its assessment?**

**c) How low would Alectra allow reliability to drop before it constrains DERs?**

**Response:**

a) Alectra Utilities performs the capacity assessment for new DERs connection and system capacity annually, based on annual load and DER penetration forecasts. Alectra Utilities analyzes the power quality case by case, when concerns have been noted during normal operation or by the customer. The traditional method of connecting a new DER into our distribution system is through Connection Impact Assessment ("CIA"). If the CIA study shows the connection of the next DER is adversely affecting reliability or power quality, Alectra Utilities will not allow its connection or proposes mitigation methods. However, with the deployment of a Distributed Energy Management System ("DERMS") platform, integrated to Alectra Utilities' control and operation systems, Alectra Utilities will gain visibility and control to the DERs. This allows Alectra to maximize the number of DERs connected to our distribution system through dynamic control of the underlying assets - either through traditional utility assets like shunt capacitors and tap chargers or through active and reactive power injection from DERs.

b) Alectra Utilities' reliability/power quality metrics are based on International Electro-technical Commission (IEC) Institute of Electrical and Electronic Engineers (IEEE) Standard 519-1992, Canadian Standards Association (CSA) Standard CAN3-C235-83 (R2006), or latest edition, for voltage regulation and interconnection of distributed resources and electricity supply systems. Alectra also publishes its reliability metrics in terms of SAIDI and SAIFI, annually.

c) Please refer to the response for a) and response to EP-31 b).

**EP-33**

**Reference: Exhibit 04, Tab 01, Schedule 01, Appendix A16, Distributed Energy Resources ("DER) Integration, Page 23**

**Question:**

a) **What is a "DER Control Platform"? Please provide a detailed breakdown of its $1.6 million cost estimate.**

b) **What is a "Smart DER Platform"? How is it different from other DER platforms that are not smart? Please provide a breakdown of the $2.4 million cost estimate.**

**Response:**

a) Please refer to page 10-11 in Exhibit 4, Tab 1, Schedule 1, Appendix A16 for discussion on DER Control Platform. The planned DER Control Platform project is to integrate DERs with Alectra Utilities' traditional distribution operation technology systems. It will enable Alectra Utilities to: build capabilities that could predict the grid operational impacts of DERs; help mitigate power quality issues associated with DERs; and reduce peak demand. These capabilities will be built as part of the overall DER Control Platform, also known as Distributed Energy Resource Management System ("DERMS"), further enabling a Virtual Power Plant ("VPP"), with integrated controls and real time signals in order to operationalize DERs as an aggregated source of capacity and storage.

The DER Control Platform is a hierarchy control system, encompassing local distributed energy resource management system (L-DERMS) and enterprise distributed energy resource management system (E-DERMS), that provides an integration backbone for DERs with hardware and software services to be controlled and managed through Alectra Utilities' core operational and control systems.

Through the DER Control Platform, the utility aims to provide a flexible and scalable solution to effectively engage with its customers with DERs, support optimization of their DER utilization and provide automated business processes around DER management. The platform will be designed to address challenges in utility planning, communications and operational processes for Alectra Utilities to ensure successful integration of DERs. For instance, by utilizing field data from GIS, SCADA and DERs, the platform will be able to support the development of efficient models to address the challenges in utility network planning, as well as ancillary decision-making at operational and planning levels.

The DER Control Platform will help Alectra Utilities to ensure that growing DER challenges are met through supporting efficient network planning and impact analysis and providing visibility of the entire network state in real-time. It will provide the ability to define, aggregate, forecast, and control DER within Alectra Utilities' service territory. For instance, using DER generation forecast analysis and DER optimization techniques, Alectra Utilities will be able to manage grid resources more effectively. Without the DER Control Platform, Alectra Utilities will not be able to realize the full potential benefit of DER integration, nor will it be able to mitigate the risks such as power quality and reliability of supply issues introduced by increasing DERs penetration.

The estimated $1.62 MM cost for the planned DER Control Platform is approximately $0.3MM each year over the period of 2020-2024. Please see Table 1 below for detailed breakdown of the cost estimate.

**Table 1 - Planned DER Control Platform Cost Estimate ($MM)**

| Investment Activity/Workstream | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| E-DERMS platform procurement, design & planning | 0.25 | 0.18 | 0.05 | 0.05 | 0.05 | 0.58 |
| E-DERMS Platform deployment and integration to Alectra's SCADA | 0.06 | 0.12 | 0.05 | 0.05 | 0.05 | 0.33 |
| L-DERMS or Local Controllers contracting and integration into E-DERMS Platform | | 0.03 | 0.23 | 0.13 | 0.08 | 0.46 |
| Full Integrated E-DERMS Platform Testing | | | | 0.11 | 0.10 | 0.21 |
| E-DERMS Dashboard customization, user manual creation and training for Alectra's control room operators | | | | | 0.06 | 0.06 |
| **TOTAL** | **0.31** | **0.32** | **0.33** | **0.33** | **0.34** | **1.62** |

b) Please refer to page 11-13 in Exhibit 4, Tab 1, Schedule 1, Appendix A16 for discussion on Smart DER Control Platform. The Smart DER platform will enable customers and the utility to transparently record the flow of electricity to and from DERs, enabling the efficient procurement of energy services, such as demand response, solar generation and frequency regulation. It will provide a robust settlement mechanism backed by timely, efficient financial transactions; provide customers with more choice over their energy and costs which will enable overall trust and customer value delivery, leading to increased customer satisfaction. It will also provide the utility with an effective means of identifying the introduction of DERs into the distribution system which is a pivotal utility problem associated with the proliferation of DERs.

In order to implement the Smart DER Platform, Alectra Utilities will leverage its existing Power.House customers to participate in an energy marketplace powered by a blockchain-based software platform. Blockchain technology essentially provides a distributed ledger that can record transactions between two parties efficiently, and in a verifiable, permanent and secure way. Through the Smart DER Platform, Alectra Utilities will issue requests for the Power.House customer systems to provide distribution energy services where each aspect of customer participation will be transacted through and recorded transparently in real-time by the platform. The Smart DER Platform will provide end-to-end visibility on customer usage and DER participation patterns, and such information can only be accessed by parties who have been granted permission through the platform. By analyzing these patterns, Alectra Utilities can prove to be a highly effective intermediary between understanding customer usage and changing customer behavior, consequently providing tangible incentives that promote the beneficial use of DERs to customers and the distribution grid.

The planned Smart DER Platform investment is estimated at $2.44MM over the period of 2020-2024, with the detailed breakdown as shown in the table below:

**Table 2 Planned Smart DER Platform Cost Estimate ($MM)**

| Investment Activity/Workstream | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Smart DER Platform data management, security and privacy Architecture | 0.05 | | | | | 0.05 |
| End-to-end detailed Solution Design and evolution/refinement | 0.05 | 0.03 | 0.03 | 0.03 | 0.03 | 0.15 |
| Contract Counterparty services development framework & interfaces | 0.15 | 0.20 | 0.20 | 0.20 | 0.20 | 0.95 |
| Metering Agent, Tokenization and Payments integration framework & interfaces | 0.10 | 0.03 | 0.05 | 0.05 | 0.06 | 0.29 |
| Exchange partner marketplace, integration framework & interface | | 0.05 | 0.15 | 0.15 | 0.15 | 0.50 |
| Insights generation and dashboard development | | 0.05 | 0.15 | 0.15 | 0.15 | 0.50 |
| **TOTAL** | **0.35** | **0.35** | **0.57** | **0.58** | **0.59** | **2.44** |

**EP-34**

**References: Exhibit 4, Appendix B, Business Cases**

**Question:**

a) **Please file a table listing all business cases filed in Appendix B with the cost of each project indicating which projects are mandatory such that cost is no object and which projects are discretionary and can be deferred if Alectra is short of funds.**

**Response:**

a) There are no projects where “cost is no object”. All capital projects at Alectra Utilities is assessed to ensure prudency and maximum value including mandatory work required to meet regulatory requirements.

Alectra Utilities evaluates each project in the capital investment plan to pace and prioritize investments based on business values, objectives and risks. The portfolio of projects presented in the DSP, reflect prudent investment needs and the most cost effective option for ratepayers. They are all necessary and produce positive outcomes for ratepayers.