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June 7, 2018

BY RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli;

RE: ANNUAL FILING UNDER BOARD-APPROVED CUSTOM INCENTIVE RATE SETTING ("CIR") PLAN AND INCENTIVE REGULATION MECHANISM ("IRM") – EB-2018-0016

Alectra Utilities Corporation ("Alectra Utilities") submits its electricity distribution rate application ("EDR") for all of its rate zones, for approval of proposed distribution rates and other charges, effective January 1, 2019, as follows:

- Horizon Utilities Rate Zone ("Horizon Utilities RZ") Custom IR Year 5 Update;
- Brampton Rate Zone ("Brampton RZ") Price Cap IR;
- PowerStream Rate Zone ("PowerStream RZ") Price Cap IR and ICM; and
- Enersource Rate Zone ("Enersource RZ") Price Cap IR and ICM.

This application incorporates, or will incorporate, OEB guidelines, reports and policy changes, where appropriate for all rate zones. The application is being filed in accordance with the OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications,* issued July 20, 2017 (the "Chapter 3 Filing Requirements").

Alectra Utilities applies for disposition of:

- Its Group 1 Deferral and Variance Accounts by rate zone. The proposed balances relate to variances accumulated in 2017. Alectra Utilities seeks rate zone-specific tariffs; and
- The balance in its Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities as of December 31, 2016 for the Horizon Utilities, Brampton, PowerStream and Enersource Rate Zones.

The application includes live versions of the following models:

- IRM Model
- ICM Model
- Revenue Requirement Work Form
- Income Tax/ PILs Work Form
- Cost Allocation Model
- RTSR Work Form
- ESM Rate Rider Model
- LRAMVA Work Form
- GA Work Form
- Capitalization Policy Rate Rider Model

The Chapter 3 Filing Requirements specify that distributors should confirm the accuracy of the billing determinants for pre-populated models. Alectra Utilities wishes to advise the OEB that at the time of this filing, OEB models for 2019 EDR Applications were not yet available. Alectra Utilities has used the 2018 OEB models for creating the models on which this application is based. Alectra Utilities has confirmed the accuracy of the billing determinants to the 2017 RRR, section 2.1.5.4.

To assist the OEB, Alectra Utilities has created a Table of Concordance for the application; these are included in the application.

Alectra Utilities provides two paper copies and has filed an electronic version of this application via RESS.

Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

Indy J. Butany-DeSouza, MBA
Vice President, Regulatory Affairs
Alectra Utilities Corporation

EB-2018-0016

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

AND IN THE MATTER OF an Application by Alectra Utilities Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2019

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ALECTRA UTILITIES CORPORATION

ANNUAL FILING UNDER BOARD-APPROVED CUSTOM INCENTIVE RATE SETTING (“CIR”) PLAN AND INCENTIVE REGULATION MECHANISM (“IRM”)

FILED: June 7, 2018

Applicant

Alectra Utilities Corporation
2185 Derry Road West
Mississauga, Ontario
L5N 7A6

Indy J. Butany-DeSouza, MBA
Vice-President, Regulatory Affairs
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Exhibit	Tab	Schedule	Contents
3	1	1	Attachments

HORIZON UTILITIES RATE ZONE

Attachment 1	Current Tariff of Rates and Charges January 1, 2018 Horizon Utilities RZ
Attachment 2	Proposed Tariff of Rates and Charges January 1, 2019 Horizon Utilities RZ
Attachment 3	Customer Bill Impacts Horizon Utilities RZ
Attachment 4	Revenue Requirement Work Form Horizon Utilities RZ
Attachment 5	Income Tax/PILS Work Form Horizon Utilities RZ
Attachment 6	IRM Model Horizon Utilities RZ
Attachment 7	GA Workform Horizon Utlities RZ
Attachment 8	Cost Allocation Model Horizon Utilities RZ
Attachment 9	Summary of Fixed/Variable Splits Horizon Utilities RZ
Attachment 10	RTSR Work Form Horizon Utilities RZ
Attachment 11	ESM Rate Rider Model Horizon Utilities RZ
Attachment 12	Lost Revenue Adjustment Mechanism Variance Account Work Form Horizon Utilities RZ
Attachment 13	2016 Final IESO Results Report Horizon Utilities RZ

BRAMPTON RATE ZONE

Attachment 14	Current Tariff of Rates and Charges January 1, 2018 Brampton RZ
Attachment 15	Proposed Tariff of Rates and Charges January 1, 2019 Brampton RZ
Attachment 16	Customer Bill Impacts Brampton RZ
Attachment 17	IRM Model Brampton RZ
Attachment 18	GA Workform Brampton RZ
Attachment 19	Disposition of Capitalization Policy Balances
Attachment 20	Lost Revenue Adjustment Mechanism Variance Account Work Form Brampton RZ
Attachment 21	2016 Final IESO Results Report Brampton RZ

POWERSTREAM RATE ZONE

ENERSOURCE RATE ZONE

Attachment 44	Incremental Capital Module Enersource RZ
Attachment 45	2017 ROE (RRR 2.1.5.6) Enersource RZ
Attachment 46	ICM Business Cases Enersource RZ
Attachment 47	ICM Revenue Requirement by Project Enersource RZ
Attachment 48	2019 Capital Expenditure by Project Enersource RZ
Attachment 49	Innovative Customer Engagement Report Enersource RZ

CERTIFICATION OF THE EVIDENCE

As President and Chief Executive Officer of Alectra Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate and is consistent with Chapters One and Three of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* issued on July 20, 2017.

Brian J. Bentz
President and Chief Executive Officer

Alectra Utilities Corporation
2019 Rate Application (EB-2018-0016)
Table of Concordance

			Rate Zones ("RZ")			
			Horizon Utilities	**Brampton**	**PowerStream**	**Enersource**
	Executive Summary	Exhibit 1, Tab 1, Schedule 1				
	Certification of the Evidence	Exhibit 1, Tab 1, Schedule 3				
3.1.2	**Components of the Application Filing**					
1	A manager's summary thoroughly documenting and explaining all rate adjustments applied for		Exhibit 2, Tab 1, Schedule 1	Exhibit 2, Tab 2, Schedule 1	Exhibit 2, Tab 3, Schedule 1	Exhibit 2, Tab 4, Schedule 1
2	The primary contact information for the application	Exhibit 1, Tab 1, Schedule 2, p. 21				
3	A completed rate generator model (i.e., IRM Model), both in electronic (i.e. excel) and PDF format		Ex 3, Tab 1, Schedule 1, Attachment 6	Exhibit 3, Tab 1, Schedule 1, Attachment 17	Exhibit 3, Tab 1, Schedule 1, Attachment 25	Ex 3, Tab 1, Schedule 1, Attachment 38
	Supplementary work forms: ICM Model, as applicable, provided by the OEB, both in electronic (i.e. excel) and PDF format				Exhibit 3, Tab 1, Schedule 1, Attachment 29	Ex 3, Tab 1, Schedule 1, Attachment 44
	Supplementary work forms: Revenue Requirement Work Form, as applicable, provided by the OEB		Ex 3, Tab 1, Schedule 1, Attachment 4			
	Supplementary work forms: Income Tax/ PILs Work Form, both in electronic (i.e. excel) and PDF format		Ex 3, Tab 1, Schedule 1, Attachment 5			
	Supplementary work forms: Cost Allocation Model, as applicable, provided by the OEB, both in electronic (i.e. excel) and PDF format		Ex 3, Tab 1, Schedule 1, Attachment 8			
	Supplementary work forms: RTSR Work Form, as applicable, provided by the OEB, both in electronic (i.e. excel) and PDF format		Ex 3, Tab 1, Schedule 1, Attachment 10			
	Supplementary work forms: ESM Rate Rider Model, as applicable, provided by the OEB, both in electronic (i.e. excel) and PDF format		Exhibit 3, Tab 1, Schedule 1, Attachment 11			
	Supplementary work forms: LRAMVA Work Form, as applicable, provided by the OEB, both in electronic (i.e. excel) and PDF format		Exhibit 3, Tab 1, Schedule 1, Attachment 12	Exhibit 3, Tab 1, Schedule 1, Attachment 20	Exhibit 3, Tab 1, Schedule 1, Attachment 28	Exhibit 3, Tab 1, Schedule 1, Attachment 42
4	A PDF copy of the current tariff sheet		Exhibit 3, Tab 1, Schedule 1, Attachment1	Exhibit 3, Tab 1, Schedule 1, Attachment 14	Exhibit 3, Tab 1, Schedule 1, Attachment 22	Exhibit 3, Tab 1, Schedule 1, Attachment 35
5	Supporting documentation cited within the application (e.g. excerpts of relevant past decisions and/or settlement agreements)		Embedded in throughout the Application, as necessary			
6	A statement as to who will be affected by the application		Exhibit 2, Tab 1, Schedule 1, p.2	Exhibit 2, Tab 2, Schedule 1, p.1	Exhibit 2, Tab 3, Schedule 1, p.1	Exhibit 2, Tab 4, Schedule 1, p.1
7	Confirmation of the Applicant's internet address		Exhibit 1, Tab 1 , Schedule 1	Exhibit 1, Tab 1 , Schedule 1	Exhibit 1, Tab 1 , Schedule 1	Exhibit 1, Tab 1 , Schedule 1
8	A statement confirming the accuracy of the billing determinants for pre-populated models		Exhibit 2, Tab 1, Schedule 7	Exhibit 2, Tab 2, Schedule 5	Exhibit 2, Tab 3, Schedule 5	Exhibit 2, Tab 4, Schedule 5
9	A text-searchable Adobe PDF format for all documents		Confirmed			
3.2.1	**Annual Adjustment Mechanism**					
1	Distributors shall use the 2018 rate-setting parameters as a placeholder until the stretch factor assignment and inflation factor for 2019 are issued		Exhibit 2, Tab 1, Schedule 2	Exhibit 2, Tab 2, Schedule 2	Exhibit 2, Tab 3, Schedule 2	Exhibit 2, Tab 4, Schedule 2
3.2.2	**Revenue-to-Cost Ratio Adjustments**					
1	Adjust revenue to cost ratios		Exhibit 2, Tab 1, Schedule 3	N/A	N/A	N/A
3.2.3	**Rate Design for Residential Electricity Customers**					
1	Threshold Test: the monthly service charge does not exceed $4 per year; If $4 is exceeded, an extension of the transition period must be applied		Exhibit 2, Tab 1, Schedule 4	Exhibit 2, Tab 2, Schedule 3	Exhibit 2, Tab 3, Schedule 3	Exhibit 2, Tab 4, Schedule 3
2	Overall bill impact test: A utility shall evaluate the total bill impact for a residential customer at the distributor's 10th consumption percentile		Exhibit 2, Tab 1, Schedule 4	Exhibit 2, Tab 2, Schedule 3	Exhibit 2, Tab 3, Schedule 3	Exhibit 2, Tab 4, Schedule 3
3	Distributors must provide a description of the method 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).		Exhibit 2, Tab 1, Schedule 4	Exhibit 2, Tab 2, Schedule 3	Exhibit 2, Tab 3, Schedule 3	Exhibit 2, Tab 4, Schedule 3
4	If the total bill impact for customers at the 10th percentile is 10% or greater, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required		N/A	N/A	N/A	N/A
5	Where the evaluation of bill impacts indicates that rate mitigation is only required for the residential class, it is the OEB's expectation that distributors will propose mitigation strategies that target only the residential class		N/A	N/A	N/A	N/A
6	All new distribution-specific residential rate riders must be calculated based on a fully fixed rate design (e.g. ICM rate riders, shared tax savings, Z-factors)		ESM - Exhbit 2, Tab 1, Schedule 6, Table 30 LRAM - Exhbit 2, Tab 1, Schedule 9, Table 52	LRAM - Exhibit 2, Tab 2, Schedule 8, Table 79 Capitalization Policy - Exhibit 2, Tab 2, Schedule 5, Table 71	LRAM - Exhibit 2, Tab 3, Schedule 8, Table 101 ICM - Exhibit 2, Tab 3, Schedule 10, Table 121	LRAM - Exhibit 2, Tab 4, Schedule 9, Table 148 ICM - Exhibit 2, Tab 4, Schedule 12, Table 168 Capitalization Policy - Exhibit 2, Tab 4, Schedule 8, Table 142
3.2.5	**Review and Disposition of Group 1 Deferral and Variance Account Balances**					
1	Calculation of the DVA disposition threshold (total claim/total kWh) to determine if the threshold of $0.001/kWh has been exceeded		Exhibit 2, Tab 1, Schedule 7, Table 39	Exhibit 2, Tab 2, Schedule 5, Table 52	Exhibit 2, Tab 3, Schedule 5, Table 77	Exhibit 2, Tab 4, Schedule 5, Table 115
2	A distributor must provide an explanation if the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing		Exhibit 2, Tab 1, Schedule 7, p.2	Exhibit 2, Tab 2, Schedule 5, p.2	Exhibit 2, Tab 3, Schedule 5, p.2	Exhibit 2, Tab 4, Schedule 5, p.2
3	A statement confirming whether any adjustments to DVA account balances previously approved on a final basis have been included in the disposition claim		Exhibit 2, Tab 1, Schedule 7, p.3	Exhibit 2, Tab 2, Schedule 5, p.3	Exhibit 2, Tab 3, Schedule 5, p.3	Exhibit 2, Tab 4, Schedule 5, p.3
4	The EDDVAR Report 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		N/A	N/A	N/A	N/A
5	A distributor must not allocate any account balances in Account 1588 RSVA - Power, Account 1580 RSVA - Wholesale Market Services Charge and Account 1589 RSVA - Global Adjustment to a wholesale market participant.		Exhibit 2, Tab 1, Schedule 7, p.5	Exhibit 2, Tab 2, Schedule 5, p.4	Exhibit 2, Tab 3, Schedule 5, p.5	Exhibit 2, Tab 4, Schedule 5, p.5
6	A distributor must 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.		Exhibit 2, Tab 1, Schedule 7	Exhibit 2, Tab 2, Schedule 5	Exhibit 2, Tab 3, Schedule 5	Exhibit 2, Tab 4, Schedule 5
7	A distributor must provide a description of its settlement process with the IESO or host distributor. It must specify the GA rate it uses when billing its customers (1st estimate, 2nd estimate or actual) for each rate class, itemize its process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. The description should detail the distributor`s method for estimating RPP and non-RPP consumption, as well as its treatment of embedded generation or any embedded distribution customers		Exhibit 2, Tab 1, Schedule 8	Exhibit 2, Tab 2, Schedule 6	Exhibit 2, Tab 3, Schedule 6	Exhibit 2, Tab 4, Schedule 6
8	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 commodity account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.		Exhibit 1, Tab 1, Schedule 3	Exhibit 1, Tab 1, Schedule 3	Exhibit 1, Tab 1, Schedule 3	Exhibit 1, Tab 1, Schedule 3

	Table of Concordance		Rate Zones ("RZ")			
3.2.6	**LRAM Variance Account**					
1	Distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year (generally all 12 months)		Exhibit 2, Tab 1, Schedule 9	Exhibit 2, Tab 2, Schedule 9	Exhibit 2, Tab 3, Schedule 9	Ex 2, Tab 4, Schedule 9
2	No peak demand (kW) savings from Demand Response (DR) programs should generally be included within the LRAMVA calculation. A distributor that wants to present empirical evidence to support DR savings in the LRAMVA can only do so as part of a cost of service or Custom IR application		Exhibit 2, Tab 1, Schedule 9	Exhibit 2, Tab 2, Schedule 9	Exhibit 2, Tab 3, Schedule 9	Ex 2, Tab 4, Schedule 9
3	Distributors must provide the LRAMVA work form in a working Microsoft Excel file to the OEB		Exhibit 3, Tab 1, Schedule 1, Attachment 12 and live model	Exhibit 3, Tab 1, Schedule 1, Attachment 20 and live model	Exhibit 3, Tab 1, Schedule 1, Attachment 27 and live model	Exhibit 3, Tab 1, Schedule 1, Attachment 42 and live model
4	A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition.		Exhibit 2, Tab 1, Schedule 9, p.3	Exhibit 2, Tab 2, Schedule 9, p.3	Exhibit 2, Tab 3, Schedule 9, p.3	Ex 2, Tab 4, Schedule 9, p.3
5	A statement confirming that LRAMVA was based on verified savings results that are supported by the LDC'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.		Exhibit 2, Tab 1, Schedule 9, p.3	Exhibit 2, Tab 2, Schedule 9, p.3	Exhibit 2, Tab 3, Schedule 9, p.4	Ex 2, Tab 4, Schedule 9, p.4
6	A summary table showing the principle and carrying charges amounts by rate class and the resultant rate riders for each rate class. A statement providing the period of rate recovery. Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not generate significant rate riders.		Exhibit 2, Tab 1, Schedule 9, p.5	Exhibit 2, Tab 2, Schedule 9, p.5	Exhibit 2, Tab 3, Schedule 9, p.5	Ex 2, Tab 4, Schedule 9, p.6
7	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.		Exhibit 2, Tab 1, Schedule 9, p.3	Exhibit 2, Tab 2, Schedule 9, p.4	Exhibit 2, Tab 3, Schedule 9, p.4	Ex 2, Tab 4, Schedule 9, p.4
8	Provide rationale 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.		Exhibit 2, Tab 1, Schedule 9, p.3	Exhibit 2, Tab 2, Schedule 9, p.3	Exhibit 2, Tab 3, Schedule 9, p.4	Ex 2, Tab 4, Schedule 9, p.4
9	A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC's Final CDM Annual Report (i.e., street lighting projects). This data can be added to the workform in Tab 8 as applicable.		Exhibit 2, Tab 1, Schedule 9, p.4	N/A	Exhibit 2, Tab 3, Schedule 9, p.4	Ex 2, Tab 4, Schedule 9, p.4
10	For OEB-approved programs approved before 2014, the submission of a third party report, in accordance with the IESO's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the distributor's lost revenue calculations, including: -Confirmation of the use of correct input assumptions and lost revenue calculations -Verified participation amounts -The net and gross impacts of each program (kW and kWh) and by each customer class, separated by year -Verification of any carrying charges requested		N/A	N/A	N/A	N/A
3.2.7	**Tax Changes**					
1	OEB policy 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 customers over a 12 month period		N/A	N/A	N/A	N/A
3.3.2	**Incremental Capital Module - Filing Requirements**					
1	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		N/A	N/A	Exhibit 2, Tab 3, Schedule 10	Exhibit 2, Tab 4, Schedule 11
2	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		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
3	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		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
4	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)		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
5	Details by project for the proposed capital spending plan for the expected in-service year		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
6	A description of the proposed capital projects and expected in-service dates		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
7	Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project. The half year rule for depreciation & CCA only applies in cases in which the ICM request coincides with the final year of the IRM plan term		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
8	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)		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
9	A description of the actions the distributor would take in the event that the OEB does not approve the application.		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
10	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		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
11	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		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
12	A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the forecasted 2018 total capital expenditures and the ACM/ICM materiality threshold.		N/A	N/A	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 29,30,31,32,33,34	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 44, 45, 46,47, 48, 49
3.3.3	**Treatment of costs for 'eligible investments' (i.e. GEA)**					
1	Distributors under Price Cap IR, who have yet to file a cost of service 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		N/A	Exhibit 2, Tab 2, Schedule 8	Exhibit 2, Tab 3, Schedule 7	Exhibit 2, Tab 4, Schedule 8
Other	**Treatment of Negligible Rate Adders and Rate Riders**					
1	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.		Exhibit 2, Tab 1, Schedule 7, p.9	Exhibit 2, Tab 2, Schedule 5, p.9	Exhibit 2, Tab 3, Schedule 5, p.10	Exhibit 2, Tab 4, Schedule 5, p.9

EXECUTIVE SUMMARY

Alectra Utilities Corporation ("Alectra Utilities") is an Ontario corporation with its corporate head office in the City of Mississauga. Alectra Utilities carries on the business of distributing electricity within the Cities of Mississauga, Hamilton, St. Catharines, Brampton, Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan, in addition to Collingwood, Stayner, Creemore and Thornbury under Ontario Energy Board ("OEB" or the "Board") Electricity Distributor Licence No. ED-2016-0360.

In April 2016, Enersource Hydro Mississauga Inc. ("Enersource"), Horizon Utilities Corporation ("Horizon Utilities"), and PowerStream Inc. ("PowerStream") filed an application (the "MAADs Application"; EB-2016-0025) pursuant to the *Handbook to Electricity Distributor and Transmitter Consolidation* (the "MAADs Handbook") asking for approval to amalgamate to form Alectra Inc. ("Alectra") (previously identified as "LDC Co" in the MAADs Application), and for Alectra to purchase and amalgamate with Hydro One Brampton Networks Inc. ("Hydro One Brampton") under section 86 of the *Ontario Energy Board Act 1998* (the "Act"). Alectra Inc. is the parent of Alectra Utilities.

As part of the MAADs Application, approvals were sought: (a) to transfer the distribution licences and rate orders for each of the applicants and Hydro One Brampton to Alectra Utilities; (b) for an electricity distributor licence for Alectra Utilities; and (c) for temporary exemptions from section 2.6.1A of the Distribution System Code ("DSC").

On December 8, 2016, the OEB issued its Decision and Order in respect of the MAADs Application. In the MAADs Decision, the OEB granted the requested approvals. It also approved a rebasing deferral period of 10 years.

During the rebasing deferral period, Alectra Utilities will operate individual rate zones ("RZ") (based on the predecessor utilities). As indicated in the MAADs Handbook and in the report entitled *Rate-making Associated with Distributors Consolidation*, issued July 23, 2007 (the "2007 Report"), as well as the subsequent report issued on March 26, 2015 (the "2015 Report"), the Alectra Utilities rate zones will continue on their current rate plan terms until such terms expire. Once expired, all rate zones will migrate to the Price Cap Incentive Rate-setting option. At its option, 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.

At present, the Brampton, Enersource and PowerStream RZs are on Price Cap IR for the purpose of setting 2019 electricity distribution rates. The ICM is available to these rate zones, as provided below.

At the time of this filing, the 2019 OEB models for IRM and ICM applications were not yet available. Alectra Utilities developed models for IRM (the "IRM Model") and ICM (the "ICM model") for use in this filing, based on the most recent OEB models available.

Overview to Requested Relief

In this Application, Alectra Utilities applies for: i) the Price Cap IR adjustment for the Brampton, Enersource and PowerStream RZs; ii) an annual adjustment for the Horizon Utilities RZ, related to the fourth and final adjustment in the 2015-2019 Custom IR rate plan term.

Alectra Utilities also applies for incremental capital funding for the PowerStream and Enersource RZs, in accordance with: the OEB's: *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications* issued July 20, 2017 ("Chapter 3 Filing Requirements"); the MAADs Handbook; the OEB's *Handbook for Utility Rate Applications* (the "Rate Handbook"), dated October 13, 2016; the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014; the subsequent *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016; and the Decision and Order of the OEB in Alectra Utilities' 2018 EDR Application Decision (EB-2017-0024; the "EDR Application Decision").

Alectra Utilities also applies for disposition of its Group 1 Deferral and Variance Accounts by rate zone. The proposed balances relate to variances accumulated in 2017. Alectra Utilities seeks rate zone-specific tariffs.

Alectra Utilities implemented a new capitalization policy in 2017 (as a result of the consolidation, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones. The change in capitalization policy results in a 2017 net impact of the financial balances in the Brampton and Enersource rate zones. Alectra Utilities proposes to recover this amount over a one year period from all customers in the Brampton and Enersource rate zones.

In its MAADs Decision, the OEB granted "*approval to the Applicants to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the Applicants and Hydro One Brampton and to seek disposition of their balances at a future date*[1]*".* Alectra Utilities will continue to track balances in the deferral and variance accounts, accordingly.

Alectra Utilities also applies for disposition of the balance in its Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"), resulting from its Conservation and Demand Management ("CDM") activities as of December 31, 2016 for the Horizon Utilities, Brampton, PowerStream and Enersource RZs.

Accordingly, Alectra Utilities submits its second electricity distribution rate application ("EDR") for all of its rate zones, as follows:

- Horizon Utilities Rate Zone ("Horizon Utilities RZ"), formerly Horizon Utilities Corporation, Custom IR Year 5 Update;
- Brampton Rate Zone ("Brampton RZ"), formerly Hydro One Brampton Networks Inc., Price Cap IR;
- PowerStream Rate Zone ("PowerStream RZ"), formerly PowerStream Inc., Price Cap IR and ICM; and
- Enersource Rate Zone ("Enersource RZ"), formerly Enersource Hydro Mississauga Inc., Price Cap IR and ICM,

for approval of proposed distribution rates and other charges, effective January 1, 2019.

Capitalization Policy

Alectra Utilities implemented a new capitalization policy in 2017 (as a result of the consolidation, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones. IFRS 10 *Consolidated Financial Statements,* states that uniform accounting policies have to be adopted for like transactions in a

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[1] EB-2016-0025 pg. 31

group of companies. Alectra Utilities continues to address accounting policy conformance. Further, IFRS 3 *Business Combinations* prescribes that the accounting policies of the parties to the merger should align to the acquirer's policy. IFRS 3 provides guidance on identifying the acquirer by assessing the relative voting rights in the combined entity after the merger; the acquirer being the combining entity whose owners, as a group, receive the largest portion of voting rights in the combined entity.

For the predecessor companies that formed Alectra Utilities, PowerStream is the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities adopted the PowerStream capitalization policy.

The OEB established three new deferral accounts to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs, in Procedural Order No. 3, as part of Alectra Utilities' 2018 EDR Application proceeding. In the EDR Application Decision, the OEB stated that: "*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, 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.* Further, the OEB stated that: "*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*[2]*.*"

Alectra Utilities implemented a new capitalization policy in 2017(as a result of the consolidation, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones. The change in capitalization policy

[2] EB-2017-0024 pg. 81

results in a 2017 net impact of the financial balances in the Brampton and Enersource rate zones. Alectra Utilities proposes to recover this amount over a one year period from all customers in the Brampton and Enersource rate zones.

Incremental Capital Module

As the OEB has confirmed in its own reports, the MAADs Decision and the EDR Application Decision, the ICM is available to consolidating distributors. The purpose of the ICM is to afford consolidating distributors the opportunity to finance capital investments without having to rebase earlier than expected.

As the OEB specifically indicated in the MAADs Decision:

> *"The 2015 Report extended the availability of the Incremental Capital Module (ICM), an additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned." (p.6)*

In making this decision, the OEB was aware of Alectra Utilities' intention to file ICM applications during the deferred rebasing period. Again, as the OEB outlined in the MAADs Decision: *"The applicants expect to file an ICM in each year for each rate zone under Price Cap IR during the deferred rebasing period.[3]"*

Further, at page 12 of the MAADs Decision, the OEB stated that:

> *"The Handbook provides guidance on how the OEB reviews consolidation applications and clarifies the OEB's rate-making policy associated with consolidation. As with any articulated OEB policy, the OEB examines the facts of a specific application. The OEB has considered the specific facts in this application and is of the view that the features of this transaction are anticipated within the framework of the OEB's policy and the outcomes are*

[3] EB-2016-0025, Decision of the Board, December 8, 2016, p.10.

> *aligned with the articulated policy objective of improving the efficiency of electricity distribution."*

Finally, in the EDR Application Decision, the OEB held that:

> *"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) 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) and in the Handbook to Electricity Distributor and Transmitter Consolidations (MAADs Handbook)."*

This application is consistent with OEB policy in relation to the availability of, and basis for, ICM funding to consolidating distributors.

PowerStream and Enersource Rate Zones

Alectra Utilities has capital investment needs for the PowerStream and Enersource RZs for 2019 that are not funded through existing distribution rates.[4] These needs reflect significant, incremental, and discrete projects, as contemplated by the EDR Application Decision .Alectra Utilities is filing an ICM application in respect of each of these rate zones, to meet these capital investment needs. The needs fall into the following categories: system renewal; system access; and system service. The specific projects that comprise the PowerStream and Enersource RZ's ICM requests, are set out in Attachments 31 and 46, respectively.

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[4] PowerStream has an existing OEB reviewed DSP which spans 2016-2020. This was filed as part of PowerStream's previous electricity distribution rate ("EDR") application (EB-2015-0003). Brampton has an existing OEB reviewed DSP which spans 2015-2019. That DSP was filed as part of the Hydro One Brampton Networks Inc.'s 2015 EDR application (EB-2014-0083).Enersource has an existing OEB reviewed DSP which spans 2018-2022. That DSP was filed as part of the Alectra's 2018 EDR application (EB-2017-0024).

System Renewal. System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets. Alectra Utilities faces a challenge with aging electrical distribution infrastructure in the Enersource RZ. Sections of the Enersource RZ electrical distribution system are more than 50 years old, and are at the end of life.

Alectra Utilities is committed to extending the lifespan of its assets in order to minimize the cost impact of replacement on its customers. However, there comes a time when distribution infrastructure can no longer be repaired, and must be replaced. Investment in system renewal projects is necessary, as a result.

System renewal investments are driven by the identification of assets whose performance has reached a sub-standard level and poses a risk of not being able to operate as needed. Alectra Utilities uses a bottom-up approach in the Enersource RZ to identify areas that require renewal based on: asset condition assessment; inspection records; and analysis of system performance trends. Alectra Utilities also considers the consequences of asset performance, deterioration or failure, with reference to: asset performance-related operational targets; asset lifecycle optimization practices; and the number of customers affected by a failure of the assets.

An example of a system renewal project is the Rometown Overhead System Rebuild (the “Rometown Project”). As explained in the Rometown Overhead System Rebuild Business Case, filed herewith as Attachment 46, Alectra Utilities has identified a number of poles in poor condition, resulting from: rotting; mechanical damage; evidence of insect infestation; and pole cracking. Pole line failure is a public safety hazard and introduces operational risks related to reliability. The 2016 Asset Condition Assessment (“ACA”) identified 34.3% of poles in this area as “Poor” and 28.3% as “Fair, based on parameters of physical condition and mechanical damage. Where the 2019 Pole Replacement Program replaced individual poles throughout the rate zone based on identified hazards and poor condition, the Rometown Project replaces the existing substandard overhead system in the area and brings it to present day standard. The project not only includes the replacement of poles, but also the replacement of: the substandard overhead system configuration; problematic insulators; and replacement of damaged grounds, while incorporating animal contact protection and improved clearances for enhanced safety. Alectra Utilities engaged Innovative Research Group (“Innovative”) to undertake customer engagement for the ICM projects in the PowerStream and Enersource rate zones. Based on the Customer Engagement feedback, Alectra Utilities’ customers in the Enersource RZ indicated support to at least replace the most pressing overhead system components now; a large portion of customers survey preferred to replace all of the overhead system or to replace the overhead system with an underground one. The proposed solution is to proceed with a full replacement of the overhead system in the Rometown.

System Access. System access investments are comprised of projects outside of Alectra Utilities' control that are required to meet customer service obligations to provide customers with access to electricity services via the distribution system and include modifications (including asset relocation) to the distribution system.

The York Region Rapid Transit ("YRRT") VIVA Bus Rapid Transit ("BRT") Project is a system access investment. It is not included in distribution rates. As explained in the YRRT VIVA BRT Business Case, included in Attachment 31, Alectra Utilities has been relocating overhead and underground distribution assets in the PowerStream RZ to accommodate the YRRT Corporation's BRT developments. In order to meet the transportation needs resulting from projected population growth, York Region revised its original 2009 Transportation Master Plan in 2016. The BRT development phases, currently under construction and impacting the PowerStream RZ, include two project sections along Yonge Street totaling 6.5 km and two project sections along Highway 7. In addition, the above-mentioned activities affect several other roadways; totaling 8.5 km. Alectra Utilities is obligated to relocate its distribution plant to facilitate transportation infrastructure developments by applicable road authorities in accordance with the *Public Service Works on Highways Act.* The scope of the relocation work is determined from designs and construction timelines received from YRRT, RapidLink and EllisDon Capital Inc. and Coco Paving Inc. ("EDCO").

System Service. System service investments are driven by Alectra Utilities' expectations that the evolving use of the system may create capacity constraints or adversely impact system reliability. System service investments needs are driven by changing load demands in specific areas which cannot be met by the current capacity of the distribution system as well as system operational constraints identified through internal and external analysis. Alectra Utilities considers key drivers such as city development plans, regional planning and technology innovation to improve operational efficiency.

An example of a system service investment project is the Barrie TS Upgrade, as provided in the business case, included in Attachment 31. Barrie TS is owned and operated by Hydro One.

Hydro One has scheduled a rebuild of the station in 2019, as the station's equipment (i.e., power transformers, switchgear; circuit breakers, switches and ancillary station equipment) have reached end-of-life. Alectra Utilities is required to relocate six feeders that service customers in the City of Barrie; reconfigure the Midhurst feeder; and install corresponding wholesale revenue metering equipment in compliance with IESO market rules.

Customer Engagement

On October 13, 2016, the OEB released the Rate Handbook. The Rate Handbook directs 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."*[5]

Mindful of this direction, Alectra Utilities engaged Innovative to undertake customer engagement for the ICM projects in the PowerStream and Enersource rate zones. This is a continuation of the customer engagement activities undertaken for the Enersource RZ Distribution System Plan ("DSP") and ICM projects in Alectra Utilities' 2018 EDR Application. Further, Alectra Utilities has considered the submissions from OEB Staff and Intervenors during the 2018 EDR Application proceeding in order to refine its 2019 ICM-related customer engagement. Alectra Utilties has also considered and had regard to the OEB's findings in the 2018 Application proceeding.

As previously discussed, Alectra Utilities engaged Innovative to solicit feedback from customers on proposed incremental capital funding. The Innovative Report is provided herewith as Attachment 34 (PowerStream RZ) and Attachment 49 (Enersource RZ). As set out there, a telephone survey was conducted using stratified random samples for Residential and General Service Customers; an online survey was also deployed for Large Use Customers. This approach allowed Alectra Utilities to capture customers' views on the emerging needs or shifting priorities and to generate feedback on the specific projects being considered for this application.

The engagement shows that most customer groups support the ICM projects tested at the investment levels proposed or even higher.

This Annual Filing incorporates, or will incorporate, the following guidelines, reports and policy changes, where appropriate for all rate zones:

- OEB Cost of Capital Parameters Update – to incorporate the cost of capital parameters issued November 23, 2017 with a subsequent update anticipated in November 2018;

[5] Handbook for Utility Rate Applications; October 13, 2016; p.11

- Board Policy – New Cost Allocation Policy for Street Lighting Rate Class (EB-2012-0383), issued June 12, 2015;
- Amending O.Reg 493/01 Removal of Debt Retirement Charge to Residential customer for implementation January 1, 2016;
- OEB Policy: – *A New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410) issued April 2, 2015;
- OEB Policy: - Ontario Electricity Support Program (EB-2015-0148);
- *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* - (EB-2014-0278) issued December 19, 2014;
- *Empirical Research in Support of Incentive Rate-Setting: 2017 Benchmarking Update* for determination of Stretch Factor Assignments for 2017 dated August 17, 2017;
- *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 3 Incentive Rate Setting Applications* issued July 20, 2017 (the “Chapter 3 Filing Requirements”);
- *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rates Applications - Chapter 2 Cost of Service* issued July 20, 2017;
- *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (“RRFE”) issued October 18, 2012;
- *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) issued April 26, 2012;
- *Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities*, issued December 11, 2009;
- *Report of the Board on Electricity Distributors’ Deferral and Variance Account Review Initiative* (“EDDVAR”) issued July 31, 2009;
- *Report of the Board on the Updated Policy for the Lost Revenue Adjustment Mechanism (“LRAMVA”) Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs issued May 19, 2016;*

- *Revision 4.0 of the Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates, dated June 28, 2012;*
- *Chapter 3 of the Filing Requirements for Transmission and Distribution Applications - July 25, 2014;*
- *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors – November 21, 2013, corrected December 4, 2013;*
- *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;*
- *Chapter 5 of the 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 on Performance Measurement for Electricity Distributors: A Scorecard Approach – March 5, 2014;*

- *Report of the Board on the New Policy Options for the Funding of Capital Investments: The Advanced Capital Module – September 18, 2014;*
- *Report of the Board on the New Policy for Funding of Capital Investments: Supplemental Report – January 22, 2016; and*
- *Report of the Board on Defining Ontario's Typical Electricity Customer – April 14, 2016.*

Alectra Utilities provides an executive summary and relief sought by rate zone, below.

Horizon Utilities RZ

The Horizon Utilities RZ comprises the Cities of Hamilton and St. Catharines.

Horizon Utilities filed a Custom Incentive Rate-setting Application (EB-2014-0002) with the OEB on April 16, 2014, for electricity distribution rates effective: January 1, 2015; January 1, 2016; January 1, 2017; January 1, 2018; and January 1, 2019.

Horizon Utilities and the Intervenors filed a partial settlement proposal with the OEB (the "Settlement Proposal") on September 22, 2014. On October 10, 2014, the OEB advised that it had accepted the Settlement Proposal. The Settlement Proposal specified that the parties to the Settlement Proposal had agreed to the revenue requirement for each of the years 2015-2019, effective January 1 of each year, subject to annual adjustments. The actual effective dates for rates for each of those years would be contingent on the timing of the Annual Filing by Horizon Utilities and the OEB's approval.

The OEB issued its Decision and Order on the Custom IR Application on December 11, 2014.

This is the fourth and final Annual Filing for the Horizon Utilities RZ in its 2015-2019 Custom IR rate plan term, pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") and pursuant to the Decision of the Board in Horizon Utilities' Custom IR Application and its 2016, 2017 and 2018 Annual Filings, for approval of its proposed distribution rates and other charges, effective January 1, 2019. This annual filing impacts customers in the Cities of Hamilton and St. Catharines.

Alectra Utilities has calculated adjustments to its 2019 revenue requirement for the Horizon Utilities RZ using the Cost of Service Models (i.e., Revenue Requirement Work Form, Income Tax/PILs Work Form, 2018 RTSR Work Form and Cost Allocation Models) and directions provided by the Board in July 2017 for 2018 filers. Alectra Utilities has used the IRM Model to determine disposition of the deferral and variance accounts for the Horizon Utilities RZ in Tabs 3 through 8 and the LRAMVA workform to determine the disposition of the LRAMVA balance resulting from CDM activities as of December 31, 2016.

Alectra Utilities' Horizon Utilities RZ Manager's Summary will address the following:

i. Off-ramps;
ii. Reopeners and Generic Policy Changes;
iii. Annual adjustments; and
iv. Models used to calculate the adjustments and any modifications made.

Relief Sought – Horizon Utilities RZ

Alectra Utilities is seeking OEB approval of the following items for the Horizon Utilities RZ:

a. The calculation of the 2017 Regulated Return on Equity ("ROE") for the purposes of earnings sharing;
b. The calculation of its 2017 capital additions for the purpose of calculating the 2017 entry to the Capital Investment Variance Account;
c. The continuation of the implementation of the New Distribution Rate Design for residential customers;
d. A reduction to the 2019 Street Lighting Class revenue-to-cost ratio ("RCR") by 6.67% to 100.00% from the 2018 RCR of 106.66%;
e. The clearance of the balances recorded in certain deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;
f. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A customer;
g. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

h. An adjustment to retail transmission service rates effective January 1, 2019;

i. Disposition of LRAMVA amounts related to CDM activities over a one-year period;

j. That its current (i.e., 2018) rates, provided in Attachment 1, be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

Brampton RZ

The Brampton RZ comprises the City of Brampton. Alectra Utilities has a Price Cap IR rate plan for the Brampton RZ. This application impacts all customers in the City of Brampton.

At the time of this filing, 2019 OEB models for IRM applications were not yet available. Alectra Utilities developed its model for the IRM ("IRM Model") for inclusion in this filing and used Version 2.0 of the Board's LRAMVA workform.

Alectra Utilities' Brampton RZ Manager's Summary will address the following items:

a. Annual Price Cap Adjustment Mechanism;

b. Rate Design for Residential Electricity Customers;

c. Electricity Distribution Retail Transmission Service Rates;

d. Review and Disposition of Group 1 Deferral and Variance Account Balance;

e. Financial impact of the new capitalization policy in 2017;

f. 2019 Renewable Generation Connection Rate Protection;

g. Disposition of LRAM Variance Account;

h. Summary of Rates and Riders Requested; and

i. Summary of Bill Impacts.

Relief Sought – Brampton RZ

Alectra Utilities is seeking OEB approval of the following items for the Brampton RZ:

a. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The continuation of the implementation of the new distribution rate design for residential electricity customers;

c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

e. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. The recovery of the net financial impact of the new capitalization policy in 2017 through rate rider over a one year period effective January 1, 2019;

g. An adjustment to the retail transmission service rates effective January 1, 2019;

h. 2019 Renewable Generation Connection Rate Protection from provincial ratepayers;

i. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period; and

j. Current (i.e., 2018) rates provided in Attachment 14 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

PowerStream RZ

The PowerStream RZ comprises the Cities of Barrie, Markham, Vaughan and the Towns of Aurora, Richmond Hill, Alliston, Beeton, Bradford West Gwillimbury, Penetanguishene, Thornton, and Tottenham. Alectra Utilities has a Price Cap IR rate plan for the PowerStream RZ. This application impacts all customers in the above-mentioned cities and communities.

At the time of this filing, 2019 OEB models for IRM and ICM applications were not yet available. Alectra Utilities developed its own models for the IRM ("IRM Model") and ICM ("ICM Model") for inclusion in this filing and used Version 2.0 of the Board's LRAMVA workform.

Alectra Utilities' PowerStream RZ Manager's Summary will address the following items:

a. Annual Price Cap Adjustment Mechanism;
b. Rate Design for Residential Electricity Customers;
c. Electricity Distribution Retail Transmission Service Rates;
d. Review and Disposition of Group 1 Deferral and Variance Account Balance;
e. Renewable Generation Connection Rate Protection;
f. Disposition of LRAM Variance Account;
g. Incremental capital funding;
h. Summary of Rates and Riders Requested; and
i. Summary of Bill Impacts.

Relief Sought – PowerStream RZ

Alectra Utilities is seeking OEB approval of the following items for the PowerStream RZ:

a. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;
b. The continuation of the implementation of the new distribution rate design for residential electricity customers;
c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;
d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A customer;
e. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A customer;

f. An adjustment to the retail transmission service rates effective January 1, 2019;

g. 2019 Renewable Generation Connection Rate Protection from provincial ratepayers;

h. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period;

i. Incremental capital rate riders effective January 1, 2019 until the next rebasing application;

j. Current (i.e., 2018) rates provided in Attachment 22 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

Enersource RZ

The Enersource RZ comprises the City of Mississauga. Alectra Utilities has a Price Cap IR rate plan for the Enersource RZ. This application impacts all customers in the City of Mississauga.

At the time of this filing, 2018 OEB models for IRM and ICM applications were not yet available. Alectra Utilities developed its own models for the IRM ("IRM Model") and ICM ("ICM Model") for inclusion in this filing and used Version 2.0 of the Board's LRAMVA workform.

Alectra Utilities' Enersource RZ Manager's Summary will address the following:

a. Annual Price Cap Adjustment Mechanism;

b. Rate Design for Residential Electricity Customers;

c. Electricity Distribution Retail Transmission Service Rates;

d. Review and Disposition of Group 1 Deferral and Variance Account Balance;

e. Financial impact of the new capitalization policy in 2017

f. Renewable Generation Connection Rate Protection;

g. Disposition of LRAM Variance Account;

h. Incremental capital funding;

i. Summary of Rates and Riders Requested; and

j. Summary of Bill Impacts.

Relief Sought – Enersource RZ

Alectra Utilities is seeking OEB approval of the following items for the Enersource RZ:

a. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The continuation of the implementation of the new distribution rate design for residential electricity customers;

c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

e. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. The refund of the net financial impact of the new capitalization policy in 2017 through rate rider over a one year period effective January 1, 2019;

g. An adjustment to the retail transmission service rates effective January 1, 2019;

h. 2019 Renewable Generation Connection Rate Protection from provincial ratepayers;

i. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period;

j. Incremental capital rate riders effective January 1, 2019 until the next rebasing application;

k. Current (i.e., 2018) rates provided in Attachment 35 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

Proposed Effective Date of Rate Order

Alectra Utilities proposes that the OEB make its Rate Order, together with the other relief sought in this Annual Filing, effective January 1, 2019. A list of requested approvals is set out in each rate zone's Manager's Summary at Exhibit 2, Tab 1, Schedule 1; Exhibit 2, Tab 2, Schedule 1, Exhibit 2, Tab 3, Schedule 1 and Exhibit 2, Tab 4, Schedule 1, for the Horizon Utilities, Brampton, PowerStream and Enersource RZs, respectively. The proposed Tariff of Rates and Charges is provided in Attachments 2, 15, 23 and 36 for the Horizon Utilities, Brampton, PowerStream and Enersource RZs, respectively.

Alectra Utilities requests that the Board declare each of the respective RZ's current (i.e., 2018) rates provided in Attachments 1, 14, 22 and 35, as interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates, effective January 1, 2019.

Alectra Utilities requests that, in the event that the Board is unable to provide a Decision and Order in this Application for rates effective on January 1, 2019, the Board approve rate riders (including in respect of incremental capital) that would provide for the recovery of foregone revenue for the period from January 1, 2019 to the implementation date of the 2019 Tariff of Rates and Charges.

Form of Hearing Requested

Alectra Utilities requests that this Annual Filing be disposed of by way of a written hearing.

Notice of Application

Upon receipt of the Letter of Direction from the Board, Alectra Utilities will arrange to have:

A copy of the Notice, the application and evidence posted in a prominent place on Alectra Utilities' website at: www.alectrautilities.com under Regulatory. It will also be posted through the following social media accounts on Twitter - @AlectraLink and Facebook - /AlectraUtilities.

A copy of the Notice, the application and evidence, and any amendments thereto, made available for public review at the offices of Alectra Utilities.

An Affidavit filed, with the OEB in both electronic and paper forms proving completion of the above matters immediately thereafter.

A copy of the Notice, application and evidence, and any amendments thereto, to anyone requesting the material.

Contact Information

Alectra Utilities requests that all documents filed with the Board in this proceeding be served on the undersigned.

All of which is respectfully submitted this 7th day of June, 2018.

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HORIZON UTILITIES RATE ZONE

MANAGER'S SUMMARY

Horizon Utilities filed a Custom Incentive Rate-setting Application (the "Custom IR Application", (Board File No. EB-2014-0002) with the Board on April 16, 2014, pursuant to section 78 of the *OEB Act*, (Schedule B), seeking approval for five years of distribution rates effective on January 1 of each year from 2015 to 2019.

The following eight parties requested and were granted intervenor status in that proceeding:

- Association of Major Power Consumer in Ontario ("AMPCO");
- Building Owners and Managers Association ("BOMA");
- City of Hamilton ("Hamilton");
- Consumers Council of Canada ("CCC");
- Energy Probe Research Foundation ("Energy Probe");
- School Energy Coalition ("SEC");
- Sustainable Infrastructure Alliance of Ontario ("SIA"); and
- Vulnerable Energy Consumers Coalition ("VECC").

A Settlement Conference was held on August 27-29, 2014. All intervenors of record participated at the Settlement Conference except SIA and Hamilton. A partial settlement was reached and a Settlement Proposal was filed with the Board on September 22, 2014. Issues pertaining to Cost Allocation and Rate Design remained unsettled. An Oral Hearing on the unsettled issues was held on September 30, October 1, October 9, and October 10, 2014. The Board advised that it had approved the Settlement Proposal on October 10, 2014.

The Board issued its Decision and Order on the outstanding matters in the Custom IR Application on December 11, 2014, and its Final Rate Order on the Custom IR Application on January 8, 2015, for rates effective January 1, 2015.

On August 11, 2016, Horizon Utilities filed its second annual update for rates effective January 1, 2017. The OEB issued its decision on January 12, 2017 on all matters in the Annual Filing.

On July 7, 2017, Alectra Utilities filed the third annual update for the Horizon Utilities RZ, for rates effective January 1, 2018. The OEB issued its 2018 EDR Application Decision on April 5, 2018 (revised April 6, 2018) on all matters in the Annual Filing. The Annual Filings incorporated changes as a result of the OEB's New Cost Allocation Policy for the Street Lighting Rate Class (EB-2012-0383), issued June 12, 2015; changes to the revenue to cost ratio for the Street Lighting Rate Class as a result of the OEB's Decision and Order for EB-2015-0075; and changes as a result of the New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) issued by the OEB on April 2, 2015.

The New Cost Allocation Policy required distributors to update the cost allocation model to incorporate a street light adjustment factor ("SLAF") for allocating costs. The OEB stated in its Decision on Horizon Utilities Custom IR Application that in the event that there is direction from the Board with respect to a new policy concerning the methodology for cost allocation related to street lighting which is applicable to Horizon Utilities, the Board was of the view that the Settlement Agreement provided for Horizon Utilities to adjust street lighting rates accordingly. Accordingly, Horizon Utilities implemented the SLAF in its 2016 cost allocation model. In addition to the implementation of the SLAF, the OEB directed Horizon Utilities, in its Decision on Horizon Utilities Annual Filing EB-2015-0075, to phase in a reduction to the revenue to cost ratio ("RCR") for the Street Lighting Class from 120% in 2016 by 6.6% per year in each of 2017 to 2019. Accordingly, Horizon Utilities updated its rate design model for 2017 to include a RCR 113.33% for the Street Lighting class.

As it relates to changes in distribution rate design, the OEB stated in its policy*: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) issued April 2, 2015: "The OEB expects that all distributors will transition to fixed rates in equal increments over a four- year period."* Accordingly, Horizon Utilities RZ incorporated the first, second and third year transition adjustment in its proposed rates for 2016, 2017 and 2018 in a manner consistent with OEB policy.

Alectra Utilities is now seeking adjustments to 2019 rates for the Horizon Utilities RZ, in accordance with the Settlement Proposal and the Decision and Order on Horizon Utilities' Custom IR Application; and the Decision and Order on the 2016, 2017 and 2018 Annual Filings.

Alectra Utilities is seeking OEB approval of the following items for the Horizon Utilities RZ:

a. The calculation of the 2017 Regulated Return on Equity ("ROE") for the purposes of earnings sharing;

b. The calculation of its 2017 capital additions for the purpose of calculating the 2017 entry to the Capital Investment Variance Account;

c. The continuation of the implementation of the New Distribution Rate Design for residential customers;

d. To reduce the 2018 Street Lighting Class revenue-to-cost ratio ("RCR") by 6.67% to 100.00% from the 2018 RCR of 106.67%;

e. The clearance of the balances recorded in Group 1 Deferral and Variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

f. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and Class B customer;

g. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

h. An adjustment to retail transmission service rates effective January 1, 2019;

i. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period; and

j. Current (i.e., 2018) rates provided in Attachment 1 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

This Annual Filing has been prepared in accordance with the Decisions of the Board in Horizon Utilities RZ's 2015 Custom IR, 2016, 2017 and 2018 Annual Filing Applications and relevant OEB guidelines and requirements. Specifically, changes to OEB policies on distributor rate design, changes to the revenue allocated to unmetered load customers resulting from the Board's New Cost Allocation policy; and changes to revenue-to-cost ratio for the Street Lighting class.

ANNUAL ADJUSTMENTS AND GENERIC POLICY CHANGES

Generic Policy Changes

The Parties to the Settlement Proposal agreed to the list of reopeners proposed in the Custom IR Application. Each reopener agreed to, is listed below with corresponding relief sought, if applicable:

- *Changes to income tax rates and laws.* At the time of the submission of this Annual Filing, Alectra Utilities is not aware of changes to income tax rates and laws that would impact the calculation of its 2019 revenue requirement. If there are any such changes prior to the Board rendering its Decision on this Annual Filing, the Alectra Utilities will advise the OEB and update this Annual Filing, accordingly.
- *Changes to OEB policies on distributor rate design.* In the *Report of the Board: A New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410), issued April 2, 2015, the OEB confirmed that rates for Residential customers would be migrated to a fixed monthly distribution charge over a four-year transition period commencing in 2016 and ending in 2019. A letter, issued by the OEB on July 16, 2015, instructed distributors to conduct further analysis on the impact that the new fixed rate design would have on the 10^{th} percentile of energy consuming customers. Alectra Utilities has incorporated the fourth year transition adjustment in its proposed rates for 2019 for the Horizon Utilities RZ and conducted the analysis on the 10^{th} consumption percentile of energy consuming customers. This adjustment is discussed in further detail below.
- *Changes to environmental laws that would impact business requirements and processes resulting in increased expenditures*. At the time of this Annual Filing, Alectra Utilities is not aware of changes to environmental laws that would impact business requirements and processes resulting in increased expenditures. If there are any such changes prior to the Board rendering its Decision on this Annual Filing, Alectra Utilities will bring this to the attention of the Board and update this Annual Filing for the Horizon Utilities RZ, accordingly.

- *Changes to technical requirements beyond the control of the utility.* At the time of submission of this Annual Filing, Alectra Utilities is not aware of changes to technical requirements beyond its control. If there are any such changes prior to the Board rendering its Decision on this Annual Filing, Alectra Utilities will bring this to the attention of the Board and update this Annual Filing for the Horizon Utilities RZ, accordingly.

- *Items that would meet the OEB's Z-Factor criteria as defined in Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications that are material unforeseen events, that have a significant influence on the operation of the distributor.* At the time of submission of this Annual Filing, Alectra Utilities is not aware of any items that would qualify for Z-Factor adjustments. If there are any such items prior to the Board rendering its Decision on this Annual Filing, Alectra Utilities will bring this to the attention of the Board and update this Annual Filing accordingly.

- *Ministerial Directives or similar required government action to provide a service to customers (such as the previous Smart Meter Deployment,CDM and Fair Hydro Plan)* If there are any such changes prior to the Board rendering its Decision on this Annual Filing, Alectra Utilities will bring this to the attention of the Board and update this Annual Filing for the Horizon Utilities RZ, accordingly.

- *Accounting framework changes that have a significant impact on the recording of expenses and revenues.* As identified on page 30 of the Settlement Agreement, Horizon Utilities "*will not make any material changes in accounting practices that have the effect of either reducing or increasing utility earnings, unless otherwise directed to by the OEB, or by an accounting body and/or provincial or federal governments with the approval of the OEB. Where such changes are required, Horizon will note these at the time of annual filings*." Alectra Utilities implemented a new capitalization policy in 2017 (as a result of the consolidation, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones.

  IFRS 10 *Consolidated Financial Statements,* states that uniform accounting policies have to be adopted for like transactions in a group of companies. Further, IFRS 3 *Business Combinations* prescribes that the accounting policies of the parties to the merger should align to the acquirer's policy. IFRS 3 provides guidance on identifying the acquirer by assessing the relative voting rights in the combined entity after the merger; the acquirer being the combining entity whose owners, as a group, receive the largest portion of voting rights in the combined entity.

For the predecessor companies that formed Alectra Utilities, PowerStream is the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities adopted the PowerStream capitalization policy.

The OEB established three new deferral accounts to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs, in Procedural Order No. 3, as part of Alectra Utilities' 2018 EDR Application proceeding. In the EDR Application Decision, the OEB stated that: "*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, 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.* Further, the OEB stated that: "*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*[6]*.*"

The impact of the capitalization policy change on the ESM for the Horizon Utilities RZ is provided in Exhibit 2, Tab 1, Schedule 6. The proposal for disposition of the deferral accounts for the Brampton and Enersource RZs is provided in Exhibit 2, Tab 2, Schedule 7 and Exhibit 2, Tab 4, Schedule 7, respectively.

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[6] EB-2017-0024 pg. 81

Alectra Utilities continues to address accounting policy conformance.

- *Changes to amend distributor licences to allow market rates to be charged for wireless pole attachments.* On July 30, 2015, the Board issued a letter advising electricity distributors that it intends to initiate a proceeding on its own motion to amend rate-regulated distributor licences in the near future.

  On March 22, 2018, the OEB released its *Report of the Board - Wireline Pole Attachment Charges*[7]. The OEB determined that it would set a province- wide wireline pole attachment charge of $43.63 that would apply to all licensed distributors, such as Alectra Utilities, that had not received OEB approval for a distributor-specific pole attachment charge. The OEB further determined that as a transitional measure to mitigate the impact of the increase from the current $22.35 to the new $43.63, distributors without an distributor-specific charge would charge the province-wide pole attachment charge of $28.09 from September 1, 2018 to December 31, 2018, with the charge increasing to $43.63 effective January 1, 2019. Alectra Utilities has reflected this change in its 2018 OEB-approved Tariff of Rates and Charges.

  The OEB will establish a new variance account to record the excess incremental revenue from the increase in the pole attachment charge, with the balance to be refunded to ratepayers in the distributor's next cost-based rate application.

  Alectra Utilities will record entries in the newly established variance account once accounting guidance is provided by the Board.

- *Implementation of month billing.* Alectra Utilities confirms that it has implemented monthly billing for all residential and GS<50 kW customers in the Horizon Utilities RZ, effective June 23, 2017. The OEB allowed an exemption for the implementation of monthly billing for Horizon Utilities to June 30, 2017 on page 24 in its Decision and Order for the MAADs application (EB-2016-0025).

[7] EB-2015-0304

- *Changes to the revenue allocated to unmetered load customers resulting from changes to the Board's policies on cost allocation for unmetered loads.* On June 12, 2015, the OEB issued its new Cost Allocation Policy for the Street Lighting rate class (the "Cost Allocation Policy"). It required distributors to update the cost allocation model to incorporate a street light adjustment factor ("SLAF") for allocating costs rather than using a methodology based on the number of Street Lighting connections. In the Cost Allocation Policy, the Board advised that, consistent with past practice, it will implement the changes to street lighting cost allocation policy only through cost of service and Custom IR applications. However, where the Board has addressed the matter of adjustments to street lighting cost allocation and/or rate design in a prior decision, adjustments consistent with the decision will be made in subsequent mechanistic incentive rate-setting mechanism applications or as part of a Custom IR annual update. In the OEB's Decision in Horizon Utilities Custom IR Application (EB-2014-0002), the OEB identified that in the event that there is direction from the Board with respect to a new policy concerning the methodology for cost allocation related to street lighting which is applicable to Horizon Utilities, the Board's view was that the Settlement Agreement provided for Horizon Utilities to adjust street lighting rates accordingly.

  Horizon Utilities updated its 2016 cost allocation model with the SLAF and proposed that the RCR for the Street Lighting class be adjusted to 100%. In its Decision and Order, the OEB accepted Horizon Utilities' update for the SLAF and was satisfied that Horizon Utilities had updated the policy correctly. The OEB also directed that *"the implementation of a RCR of 100% for street light class should be phased in, as has been the past practice, starting with a move to 120% for 2016. Moving the RCR to 100% should be done over subsequent years at a reduction of 6.6% per year for three years. This progression will assist in gradually phasing in the change."*

  Horizon Utilities also requested approval of its cost allocation models for 2017 to 2019 in its 2016 Annual Filing. These models were based on the 2015-2019 Custom IR Decision and updated to include the SLAF, consistent with the Board's new Cost Allocation Policy. The OEB approved this request and stated in its Decision and Order that *"Subject to the findings in this Decision and any changes in policy or cost allocation* *models that the OEB directs utilities to implement during a Custom IR rate plan term, the OEB approves Horizon's cost allocation models for 2017-2019".*

In its 2017 Annual Filing, Horizon Utilities incorporated the second year transition adjustment for the Street Lighting Class in its proposed rates for 2017, in a manner consistent with OEB policy. It also proposed changes to 2017 rates for the Large Use (2) class to maintain a revenue-to-cost ratio within the range established by OEB policy. The OEB approved these changes and stated in its Decision and Order that "*The OEB approves Horizon's proposed changes to the Street Lighting and LU(2) rate classes in 2017 as the changes are consistent with prior OEB decisions and OEB policies."*

In its 2018 Annual Filing, Alectra Utilities incorporated the third year transition adjustment for the Street Lighting Class in the Horizon Utilities RZ in its proposed rates for 2018, in a manner consistent with OEB policy.

Alectra Utilities has derived its 2019 rates for the Horizon Utilities RZ using Version 3.4 of the Cost Allocation Model inclusive of the Street Lighting Adjustment Factor and the reduction to the RCR from 106.66% in 2018 to 100.00% in 2019.

Annual Adjustments

- *Changes in the Cost of Capital.* This Annual Filing has been updated for the 2018 Cost of Capital parameters issued by the OEB on November 23, 2017. Alectra Utilities will make a subsequent update for the 2019 Cost of Capital parameters, which are expected to be available prior to the Board rendering its Decision on this Annual Filing for the Horizon Utilities RZ. When the Board issues the updated values, Alectra Utilities will update this Annual Filing for the Horizon Utilities RZ, accordingly.

- *Changes to working capital.* Alectra Utilities has made changes to the working capital included in rate base for the Horizon Utilities RZ, as a result of the following changes to the Cost of Power:
  - Power and Global Adjustment charges have been updated based on the rates published by the OEB in the Regulated Price Plan ("RPP") Supply Cost Report and the RPP Prices and the Global Adjustment Modifier Report on April 19, 2018. RPP rates, the Hourly Ontario Energy Price ("HOEP") and Global Adjustment Rates were updated to the most recent rates effective from May 1, 2018 to April 30, 2019. The Power and Global Adjustment charges incorporate the bill reduction implemented as part of the Fair Hydro Plan. Alectra Utilities will update this Annual Filing for any changes to the working capital allowance included in rate base resulting from any further updates to RPP Prices.
  - Retail Transmission Service Rates ("RTSRs") have been updated to incorporate 2017 demand for the Horizon Utilities RZ, and 2018 Hydro One Uniform Transmission Rates ("UTRs") and 2017 Sub Transmission Rates ("STRs") approved by the OEB January 25, 2018 and December 21, 2016 respectively. The rates approved in Horizon Utilities' Custom IR were based on Horizon Utilities' 2013 demand and 2014 Hydro One UTRs and STRs;
  - The Smart Metering Entity ("SME") Charge has been updated to incorporate 2017 Residential and GS < 50kW customer counts. The charge approved in Horizon Utilities' Custom IR was based on Horizon Utilities' 2013 Residential and GS < 50kW customer counts. The SME Charge was also updated from \$0.79/month to \$0.57/month based on the OEB's Decision in the Independent Electricity System Operator's ("IESO") Smart Metering Entity Application approved by the OEB on March 1, 2018 (EB-2017-0290). The new SME Charge is effective January 1, 2018 to December 31, 2022;
  - The ratio of RPP vs. non-RPP volumes has been updated for 2017 actuals. The ratio approved in Horizon Utilities' Custom IR was based on 2013 actuals;
  - The Rural or Remote Rate Protection ("RRRP") Charge was updated from \$0.0013/kWh to \$0.0021/kWh as directed by the OEB in its Decision and Order

EB-2016-0362 issued December 15, 2016. The rate was further updated from $0.0021/kWh to $0.0003/kWh, as directed by the OEB in its Decision and Order EB-2017-0234 issued June 22, 2017. There was no further update to the RRRP Charge based on the OEB's Decision and Order EB-2017-0333 on RRRP and Wholesale Market Service ("WMS") Charges for January 1, 2018;

- There is no update required for the Ontario Electricity Support Program ("OESP"). The OESP was implemented January 1, 2016 and therefore not included in the Cost of Power in Horizon Utilities' Custom IR. The charge of $0.0011/kWh has been removed from the Wholesale Market Service Charges in the Cost of Power effective May 1, 2017, and therefore has not been included in the Cost of Power for this Annual Filing.

- *Changes in the tax rates.* At the time of this Annual Filing, Alectra Utilities is not aware of any changes in tax rates; allowable deductions; implementation of surtaxes; or Payments in Lieu of Taxes and other commodity taxes that would impact the calculation of revenue requirement. If there are any such changes prior to the Board rendering its Decision on this Annual Filing, Alectra Utilities will advise the Board and update this Annual Filing for the Horizon Utilities RZ, accordingly.

- *Changes in other third party pass through charges*. Other than the changes to the estimates identified above under "*Changes to working capital*", Alectra Utilities has not made any changes to third party pass through charges for the Horizon Utilities RZ.

- *CDM results that vary from plan*. Revenue requirement amounts, related to differences between actual CDM results and forecasted amounts included in the determination of rates, are recorded in Account 1568 – the LRAM Variance Account ("LRAMVA"). Section 13.4 of the Board's *Guidelines for Electricity Distributor Conservation and Demand Management (*EB-2012-0003) states that *"At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism applications, if the balance is deemed significant by the applicant"*. Alectra Utilities confirms that it is proposing to dispose of the Account 1568 balance in this Annual Filing for the Horizon Utilities RZ. The balance in Account 1568 as at the end of December 31, 2016 was $649,803.

- *Disposition of deferral and variance accounts.* Alectra Utilities confirms that the balance in the Group 1 Deferral and Variance accounts for the Horizon Utilities RZ, as at December 31, 2017, exceeds the threshold test of $0.001/kWh; Alectra Utilities requests disposition of the balances identified in Table 1, below.

Table 1 - Group 1 Total Disposition Balance – Horizon Utilities RZ

Account Description	Account	$ Total Disposition
Group 1 Accounts:		
Low Voltage	1550	$601,110
Smart Meter Entity Charge	1551	($28,637)
RSVA - Wholesale Market Service Charge - CBR B	1580	($55,880)
RSVA - Wholesale Market Service Charge excluding CBR	1580	($4,724,700)
RSVA - Retail Transmission Network Charge	1584	($192,674)
RSVA - Retail Transmission Connection Charge	1586	$443,506
RSVA - Power	1588	($5,319,006)
RSVA - Power Global Adjustment	1589	$2,405,185
Disposition and Recovery/Refund of Regulatory Balances	1595	0
Total Amount for Disposition		($6,871,097)

- *Any additional annual adjustments as identified by the Board in developing the Custom IR Application process*. The OEB has not, as of the date of this filing, included any additional annual adjustments to the Custom IR Application process. However, the Settlement Agreement included three additional annual adjustments for: an Earnings Sharing Mechanism ("ESM"); a Capital Investment Variance Account ("CIVA"); and an Efficiency Adjustment.

    - Earnings Sharing Mechanism

      The Settlement Agreement provided for the introduction of a deferral account for an ESM (1508 Sub-account "Earnings Sharing Variance Account") where earnings in excess of the Board's annual approved regulatory return on equity ("ROE"), as established by the Board in its Cost of Capital Parameters. For each of the years 2015-2019, earnings in excess of approved ROE would be divided on a 50/50 basis between Horizon Utilities and its ratepayers. The ratepayer share of earnings will be credited to a new deferral account, for clearance at the next applicable annual rate filing.

The Settlement Agreement included the following example to illustrate the timing for filing:

> *"For example: If Horizon Utilities over-earned in 2015, it would report the balance in the deferral account in the 2016 annual adjustment filing, for refund to ratepayers over the twelve months commencing January 1, 2017."*

Horizon Utilities reported its results for 2015 in the 2017 annual filing, the first year for which the ESM was in place. Horizon Utilities did not incur earnings in excess of the 2015 approved ROE and as such as of December 31, 2015 had not established, or made an entry to, the ESM deferral account 1508 Sub-account "Earnings Sharing Variance Account".

Horizon Utilities reported its results for 2016 in the 2018 annual filing, the second year for which the ESM was in place. Horizon Utilities incurred earnings in excess of the 2016 approved ROE and as such as of December 31, 2016 had established, or made an entry to, the ESM deferral account 1508 Sub-account "Earnings Sharing Variance Account" in the amount of $695,975. In the EDR Application Decision, the OEB accepted the 2016 ROE calculation of 9.87% and approved earnings sharing in the amount of $695,975 for 2016. Alectra Utilities now reports the results for Horizon Utilities for 2017 in this Annual Filing, the third year for which the ESM is in place. Regulatory net income and ROE reported for 2017 for the purposes of earnings sharing were $19,807,963 and 9.567%, respectively, as identified in Table 2 below. This compares to the regulatory net income and ROE of $18,281,100 and 8.78% approved in Horizon Utilities' 2016 Annual Filing Application (EB-2016-0077). Alectra Utilities achieved earnings in excess of the 2017 approved ROE of $1,629,640 in the Horizon Utilities RZ. Alectra Utilities has established, and made an entry to, the ESM deferral account 1508 Sub-account "Earnings Sharing Variance Account" for the Horizon Utilities

RZ. As identified on page 29 of the Settlement Agreement, Horizon Utilities is required to share 50% of the over earnings with its ratepayers; this amount is $814,820 for 2017. Alectra Utilities reported $985,377 in deferral account 1508 Sub-account Earnings Sharing Variance Account in its 2017 Reporting and Record Keeping Requirements ("RRRs") for 2017 for the Horizon Utilities RZ; which was based on an initial assessment of the calculation following the 2018 EDR Application Decision. There, the OEB stated that: "*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.* An update to the calculation based on a further assessment and review of the impact of the capitalization policy change on earnings resulted in a reduction of $170,557 in the amount of earnings sharing. Alectra Utilities proposes that this difference be reported in the 2018 deferral account balances and that the full amount of $814,820 be disposed of in 2019. Alectra Utilities will identify in its records, that the difference is related to 2017 when the 2018 earnings sharing is determined.

Alectra Utilities seeks approval for the calculation of its 2017 achieved ROE of 9.567% for the Horizon Utilities RZ, for the purposes of earnings sharing. Detailed calculations are provided in Exhibit 2, Tab 1, Schedule 6.

Table 2 – 2017 Regulatory Net Income and ROE – Horizon Utilities RZ

2017 Regulatory ROE for ESM	2017 Actuals ESM	Annual Filing EB-2016-0077	Variance
Adjusted Regulatory net income	$ 19,807,963	$ 18,281,100	$ 1,526,863
Deemed equity	$ 207,042,402	$ 208,212,985	($ 1,170,584)
ROE	9.567%	8.780%	0.787%
% Return in excess of approved in rates		0.787%	
$ Return in excess of approved in rates		$1,629,640	
Amount payable to rate payers		$814,820	

- Capital Investment Variance Account

The Settlement Agreement provided for the introduction of a deferral account (1508 Sub-account "Capital Additions Variance Account", referred to in the Settlement Agreement as the Capital Investment Variance Account, or "CIVA") to refund to ratepayers any difference in the revenue requirement should in-service capital additions be lower than, or the pacing of capital additions be slower than, forecast over the 2015-2019 period.

The Parties agreed to track variances in the revenue requirement due to variances in the capital budget. Over the term of the plan, if Horizon Utilities spends less than its capital forecast, the reduced revenue requirement impact of this will be returned to customers. The Parties agreed, and the OEB approved, that the CIVA balance would be disposed of following the end of the five-year Custom IR term, if applicable.

In the 2017 filing, Horizon Utilities reported on its capital additions for 2015. This was the first year for which Horizon Utilities was required to track variances in the revenue requirement due to variances in the capital budget. Horizon Utilities' actual capital additions for 2015 were $46,643,216, $8,328,692 higher than the capital additions of $38,314,524 forecast in its Custom IR Application. Therefore, Horizon Utilities did not establish, or make an entry to, the 1508 Sub-account CIVA. This was approved by the Board in EB-2016-0077.

In the 2018 filing, Alectra Utilities reported on the capital additions for 2016 for the Horizon Utilities RZ. This was the second year for which Alectra Utilities was required to track variances in the revenue requirement due to variances in the capital budget. Alectra Utilities reported actual capital additions for 2016 for the Horizon Utilities RZ of $44,295,265, which was $3,141,731 higher than the capital additions of $41,147,533 forecast in its Custom IR Application. Therefore, Horizon Utilities did not establish, or make an entry to, the 1508 Sub-account CIVA. This was approved by the Board in EB-2017-0024.

Alectra Utilities reports the capital additions for 2017 for the Horizon Utilities RZ in this Annual Filing. As identified in Table 3 below, Alectra Utilities' actual capital additions for 2017 in the Horizon Utilities RZ were $52,393,539, $6,767,425 higher than the capital additions of $45,626,114 forecast in its Custom IR Application. Therefore, Alectra Utilities has not established, or made an entry to, the 1508 Sub-account CIVA for the Horizon Utilities RZ. Forecasted capital additions for 2017 of $45,626,114 were approved by the Board in Horizon Utilities' Settlement Agreement for its Custom IR Application. Alectra Utilities seeks approval of Horizon Utilities' 2017 capital additions of $52,393,539 for the purpose of calculating the 2017 entry to the CIVA.

Table 3 – 2017 Capital Additions – 2017 Actual vs. Custom IR Application (EB-2014- 0002) – Horizon Utilities RZ

2017 Capital Additions	2017 Actuals	Custom IR Application (EB-2014-0002)	2017 Actual vs. Custom IR
Gross Capital Additions	$57,154,778	$50,303,114	$6,851,664
Less Capital Contributions	($4,761,239)	($4,677,000)	($84,239)
Net Capital Additions	$52,393,539	$45,626,114	$6,767,425

- Efficiency Adjustment

  The Settlement Agreement included an Efficiency Adjustment which is intended to incent Horizon Utilities RZ to maintain or improve its cohort position based on the *Board's Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update for determination of Stretch Factor Assignments for 2015* dated August 14, 2014 (August 14, 2014 Report). The Efficiency Adjustment applies in the event that Horizon Utilities RZ is placed in a less efficient cohort than the Starting Point in any year during the Custom IR term.

  The August 14, 2014 Report placed Horizon Utilities in Group III among Ontario distributors for the purpose of calculating stretch factors for 2015. The Group III Cohort is therefore the Starting Point for the rate plan. The Efficiency Factor is calculated by the difference between the Stretch Factor of the Starting Point and the Stretch Factor of the Ending Point. This Efficiency Factor is multiplied by the given rate year plan revenue requirement to provide a dollar adjustment for the purpose of calculating rates for that year as explained on page 31 of the Settlement Agreement:

  > *"As an example, if Horizon Utilities' Starting Point cohort is Group III and it moves to Group IV (Ending Point) in 2016, the Efficiency Adjustment for 2016 would be determined as (0.30% less 0.45%) * $113,484,693 = $170,227. If Horizon Utilities subsequently returns to the Starting Point cohort, no adjustment is made for that subsequent year. If Horizon*

Utilities remains in a lower cohort than the Starting Point, there will be an Efficiency Factor adjustment in each year that continues to be true".

The OEB issued the *Board's Empirical Research in Support of Incentive Rate-Setting: 2016 Benchmarking Update for determination of Stretch Factor Assignments for 2017* dated August 17, 2017, and revised September 14, 2017 (August 17, 2017 Report). The rankings from the August 17, 2017 Report are used to assign stretch factors for distributors whose rates will be adjusted under IRM in the 2018 rate setting process. The August 17, 2017 Report placed Horizon Utilities in Group III among Ontario distributors for the purposes of calculating stretch factors for 2018. The August 17, 2017 Report is the most recent report issued by the OEB; therefore Alectra Utilities has relied on this report for the purposes of determining whether an Efficiency Adjustment should be made. Horizon Utilities' Starting Point is Cohort III; the Ending Point is also Cohort III. Based on the August 17, 2017 Report, no Efficiency Adjustment should be made to the revenue requirement for the 2019 Rate Year as per the Settlement Agreement. Alectra Utilities will update the Efficiency Adjustment, if required, when the OEB issues its 2017 Benchmarking Update for determination of Stretch Factor Assignments for 2019 in August of 2018.

- The Settlement Agreement provided for the creation of a deferral account (1508 Sub-account "Special Studies") to record costs related to the development (including related intervenor costs) of a Specific Service Charge study to determine the appropriateness of, and any necessary changes to Horizon Utilities RZ's Specific Service Charges. Alectra Utilities confirms that no studies have commenced; there are no costs recorded in this account to date.
- Alectra Utilities confirms that there are no additional annual adjustments identified by the Board in the Custom IR Application process for the Horizon Utilities RZ.

Models

Alectra Utilities has included the following live models with this Annual Filing for the Horizon Utilities RZ:

- Revenue Requirement Work Form Model filed as Attachment 4 – Alectra Utilities has updated the Revenue Requirement Work Form v 7.02, as approved by the Board in the Decision on the Horizon Utilities Custom IR Application, to include the updates as the result of changes to the Cost of Power flow-through costs and Cost of Capital parameters;

- Cost Allocation Model filed as Attachment 8 – Alectra Utilities has updated the Cost Allocation Model using the Board's v 3.4 Cost Allocation Model issued on July 21, 2016, to include the updates as the result of (i) changes to the Cost of Power flow-through costs and Cost of Capital parameters; and (ii) the new Cost Allocation Policy. Attachment 9 provides a summary of the proposed Fixed and Variable percentages for 2019 for the Horizon Utilities RZ;

- RTSR Work Form – Alectra Utilities has updated the RTSR Work Form v 1.1, filed as Attachment 10, to incorporate: i) Hydro One 2018 UTRs and 2017 STRs approved by the OEB on February 1, 2018 and December 21, 2016, respectively; and ii) an update to Horizon Utilities RZ's demand from 2016 to 2017 actual values;

- Income Tax/Payments in Lieu of Taxes ("PILs") Work Form – Alectra Utilities has updated the Income Tax/PILs Work Form v 1.02, filed as Attachment 5, as approved by the Board in the Decision on the Horizon Utilities Custom IR Application, to include changes to PILs as a result of the changes to the revenue requirement from the update to the Cost of Power flow-through costs and the Cost of Capital parameters for the Horizon Utilities RZ; and

- Deferral and Variance Accounts – Alectra Utilities has updated Tabs 3 to 8 of the modified IRM Model, filed as Attachment 6, to request the approval of the disposition of Group 1 Deferral and Variance Account balances and associated carrying charges for the Horizon Utilities RZ.

- LRAMVA Work Form Model filed as Attachment 12 – Alectra Utilities has completed the LRAMVA Work Form v 2.0, to request the approval of the disposition of the LRAMVA balance resulting from CDM activities as of December 31, 2016.

Alectra Utilities did not make any material changes for the Horizon Utilities RZ to the approved Work Forms and Models from the Board's Decision on the Custom IR Application, with the exception of: (i) any updates to model versions released by the Board; (ii) any updates as the result of changes to the Cost of Power flow-through costs and Cost of Capital parameters; (iii) the implementation of the new Cost Allocation Policy

Further, Alectra Utilities used the modified version of the IRM model for the disposition of the DVAs for the Horizon Utilities RZ to be consistent with the other Alectra Utilities' RZs; and to facilitate the calculation of the bill adjustments for the Global Adjustment and Capacity Based Recovery balances.

COST ALLOCATION AND RATE DESIGN OVERVIEW

For its 2015 Custom IR Application, Horizon Utilities prepared a cost allocation model for each of the five years in the rate plan term using the OEB's v 3.1 Cost Allocation Model ("Board 3.1 CA Model") in accordance with the internal documentation contained in that model. The Board's 3.1 CA Models were used to determine each rate class' proportion of Horizon Utilities total revenue requirement in each year. The revenue-to-cost ratios for each class for each of the rate plan years were determined using the total revenues over costs in each respective year.

Horizon Utilities engaged Elenchus Research Associates ("Elenchus") to review the cost allocation models for its 2015 Custom IR Application. Based on this review, Horizon Utilities implemented refinements to: i) its definition of customer classes; ii) the methodology used to identify primary and secondary assets; iii) the allocators for customer classes based on more current load profile information; and iv) the ratio of street lighting devices per connection based on a physical count of devices and connections in the Hamilton service area.

On June 12, 2015, the OEB issued a letter titled "*Issuance of New Cost Allocation Policy for Street Lighting Rate Class"* ("Board Letter") and a study, "*Cost Allocation to Different Types of Street Lighting Configurations" (the "Navigant Study").*

The Board Letter summarizing the Board's revised policy states at page 1:

> *"A new "street lighting adjustment factor" will be used to allocate costs to the street lighting rate class for primary and line transformer assets. The street lighting adjustment factor replaces the "number of connections" allocator. The OEB will implement the policy changes during either a distributor's cost of service or custom incentive rate-setting (Custom IR) application, with a few exceptions as discussed below.*
>
> *As a related matter, effective immediately the OEB is narrowing the revenue to cost ratio policy range for the street lighting rate class from the range of 70%-120% to 80%-120%. This change is consistent with views expressed in the Report of the Board: Review of Cost Allocation for Unmetered Loads (Unmetered Loads Report), issued December 19, 2013."*

At page 3, the Board Letter states that "*The OEB adopts the recommendations included in the Navigant study for the allocation of costs associated with the different street lighting configurations."*

The Navigant recommendations are summarized at page 23 of the Navigant Report:

1. *"The allocation of the primary and line transformer assets and related costs to street lighting be calculated using a newly devised "street lighting adjustment factor" instead of the existing allocation that is based on number of street lighting connections.*

2. *The street lighting adjustment factor is calculated as the ratio of i) the four highest monthly non-coincident peak demands (NCP4) for the residential customer class divided by the number of residential customers, and ii) the NCP4 for the street lighting customer class divided by the number of streetlight devices.*

3. *No change for the allocation of the secondary assets and related costs, which is based on the number of connections."*

In its 2016 Annual Filing, Horizon Utilities updated its 2016 cost allocation model with the street lighting adjustment factor ("SLAF"). In its Decision and Order, the OEB accepted Horizon Utilities' update for the SLAF and was satisfied that Horizon Utilities had updated the policy correctly. Horizon Utilities also proposed to update the load profile for the street lighting class to include a reduction in load for the City of Hamilton as a result of its conversion in 2015 to light emitting diodes ("LEDs"). The impact of these two changes resulted in an increase in the RCR for the street lighting class from 81.35% to 160.09%. The policy in this circumstance would be to move the Street Lighting class to the top end of the Board Approved range which would result in a 120% RCR for the Street Lighting class. Horizon Utilities submitted that the street lighting class had experienced substantial rate volatility over the years and proposed to reduce the RCR to 100%.

In its Decision and Order for Horizon Utilities' 2016 Annual Filing, the OEB directed that *"the implementation of a RCR of 100% for street light class should be phased in, as has been the past practice, starting with a move to 120% for 2016. Moving the RCR to 100% should be done over subsequent years at a reduction of 6.6% per year for three years. This progression will assist in gradually phasing in the change."*

With respect to updating load profiles approved in Horizon Utilities' Custom IR Application, the OEB did not accept Horizon Utilities' proposal to update the load profile used for the street lighting class in the cost allocation model. The OEB stated in its Decision and Order for Horizon Utilities' 2016 Annual Filing that "*while the use of up to date data is preferable, there is no advantage to selective updating. Until data that is more accurate is available for all classes, Horizon must continue to use the existing load profiles for the purpose of its cost allocation model."*

As a result of, and in accordance with, the OEB's Decision and Order on its 2016 Annual Filing, the 2016 Cost Allocation and Rate Design models were based on the 2015-2019 Custom IR decision and updated to (i) include the SLAF, consistent with the Board's new Cost Allocation Policy; and (ii) include a RCR of 120% for the Street Lighting class for 2016.

Horizon Utilities also requested approval of its cost allocation models for 2017 to 2019 in its 2016 Annual Filing. These models were based on the 2015-2019 Custom IR Decision and updated to include the SLAF, consistent with the Board's new Cost Allocation Policy. The OEB approved this request and stated in its Decision and Order that "*Subject to the findings in this Decision and any changes in policy or cost allocation models that the OEB directs utilities to implement during a Custom IR rate plan term, the OEB approves Horizon's cost allocation models for 2017-2019".*

In its 2017 Annual Filing, Horizon Utilities incorporated the second year transition adjustment for the Street Lighting Class in its proposed rates for 2017 in a manner consistent with OEB policy. It also proposed changes to 2017 rates for the Large Use (2) class to maintain a revenue-to-cost ratio within the range established by OEB policy.

The OEB approved these changes and stated in its Decision and Order that "*The OEB approves Horizon's proposed changes to the Street Lighting and LU(2) rate classes in 2017 as the changes are consistent with prior OEB decisions and OEB policies.*"

In its 2018 Annual Filing, Horizon Utilities incorporated the third year transition adjustment for the Street Lighting Class in its proposed rates for 2018 in a manner consistent with OEB policy. The OEB approved these changes and stated in its Decision and Order that "*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.*"

2019 Cost Allocation and Rate Design

Alectra Utilities has completed the Board's 3.4 CA Model for 2019 for the Horizon Utilities RZ to include the new SLAF as identified in Table 4, below.

Table 4 – 2019 Street Lighting Adjustment Factor – Horizon Utilities RZ

Primary System	NCP4	Customers or Devices	Average NCP4 (per Customer or Device)
Residential	1,492,703	227,762	6.554
Street Lighting	38,022	52,273	0.727
Street Lighting Adjustment Factor (Primary System)			**9.010**

Alectra Utilities has calculated the 2019 Street Lighting Adjusted Connections based on the SLAF in Table 5 below for the Horizon Utilities RZ.

Table 5 – 2019 Street Lighting Adjusted Connections – Horizon Utilities RZ

Number of Devices (A)	52,273
Street Lighting Adjustment Factor (B)	9.010
Street Lighting Adjusted Connections C=A/B	5,802

Alectra Utilities provides a comparison of the total costs allocated from the Cost Allocation Model as approved in the 2015-2019 Custom IR Decision compared to the total costs per the revised Cost Allocation methodology (i.e., inclusive of the SLAF) in Table 6, below.

1 **Table 6 – Total 2019 Costs Allocated from Cost Allocation Model – Horizon Utilities RZ**

Rate Class	2019 Board Approved EB-2014-0002[1]	2019 Proposed	Increase/ (Decrease)
Residential	$74,896,902	$76,071,031	$1,174,129
GS < 50kW	$16,942,996	$16,881,529	($61,466)
GS > 50 to 4999kW	$24,455,048	$24,094,758	($360,290)
Standby	$1,259,659	$1,236,036	($23,623)
LU (1)	$2,477,961	$2,434,211	($43,750)
LU (2)	$1,154,214	$1,134,641	($19,573)
Sentinel Lights	$45,428	$48,255	$2,826
Street Lighting	$3,515,372	$1,835,973	($1,679,399)
Unmetered and Scattered Load	$397,736	$419,578	$21,842
Total Base Revenue Requirement	**$125,145,317**	**$124,156,012**	**($989,305)**

1. Appendix I of Horizon Utilities' Draft Rate Order, dated December 18, 2014

2 Alectra Utilities provides a comparison of the 2019 Board Approved RCRs and the 2019 RCRs
3 updated for the SLAF from the Cost Allocation Model for the Horizon Utilities RZ in Table 7,
4 below.

5 **Table 7 – 2019 Revenue to Cost Ratios before Rate Design from Cost Allocation Model -**
6 **Horizon Utilities RZ**

Rate Class	2019 Board Approved EB-2014-0002 Before Rate Design [1]	2019 Inclusive of SLAF Before Rate Design	OEB Approved Range
Residential	103.03%	101.09%	85%-115%
GS < 50kW	97.81%	98.44%	80%-120%
GS > 50 to 4999kW	95.07%	97.42%	80%-120%
Standby	71.94%	73.91%	80%-120%
LU (1)	110.01%	111.40%	85%-115%
LU (2)	95.64%	96.05%	85%-115%
Sentinel Lights	96.08%	91.58%	80%-120%
Street Lighting	82.44%	105.00%	80%-120%
Unmetered and Scattered Load	119.76%	114.60%	80%-120%

1. Appendix I of Horizon Utilities' Draft Rate Order, dated December 18, 2014

The adjusted 2019 revenue-to-cost ratios, inclusive of the new SLAF, and the necessary adjustments to move the revenue-to-cost ratios to the OEB approved target or to within the OEB approved ranges are identified in Table 8, below.

Table 8 – 2019 Revenue to Cost Ratios after Rate Design – Horizon Utilities RZ

Rate Class	2019 Board Approved EB-2014-0002 After Rate Design [1]	2019 Inclusive of SLAF After Rate Design	OEB Approved Range
Residential	103.03%	101.09%	85%-115%
GS < 50kW	97.81%	98.66%	80%-120%
GS > 50 to 4999kW	95.08%	97.64%	80%-120%
Standby	71.77%	73.91%	80%-120%
LU (1)	110.01%	111.40%	85%-115%
LU (2)	95.64%	96.27%	85%-115%
Sentinel Lights	96.08%	91.78%	80%-120%
Street Lighting	82.44%	100.00%	80%-120%
Unmetered and Scattered Load	119.76%	114.60%	80%-120%

1. Appendix I of Horizon Utilities' Draft Rate Order, dated December 18, 2014

Table 9 provides 2019 comparative information on calculated base revenue amounts used to derive proposed distribution charges.

Table 9 – 2019 Proposed Revenues and Costs – Horizon Utilities RZ

Rate Class	2019 Proposed Revenues	2019 Proposed Costs	Revenue vs. Cost $	RCR
Residential	$76,897,204	$76,071,031	$826,174	101.09%
GS < 50kW	$16,654,742	$16,881,529	($226,788)	98.66%
GS > 50 to 4999kW	$23,526,071	$24,094,758	($568,687)	97.64%
Standby	$913,005	$1,236,036	($323,031)	73.87%
LU (1)	$2,711,609	$2,434,211	$277,398	111.40%
LU (2)	$1,092,272	$1,134,641	($42,369)	96.27%
Sentinel Lights	$44,288	$48,255	($3,967)	91.78%
Street Lighting	$1,835,973	$1,835,973	$0	100.00%
Unmetered and Scattered Load	$480,848	$419,578	$61,269	114.60%
Total	**$124,156,012**	**$124,156,012**	**$0**	

Table 10 below provides a comparison of the RCRs for 2016 to 2019 updated for the SLAF and the reduction in the RCR for the Street Lighting Class from 120% in 2016 to 100% in 2019.

Table 10 – 2016 to 2019 RCRs updated for the SLAF – Horizon Utilities RZ

Rate Class	2016 Inclusive of SLAF After Rate Design	2017 Inclusive of SLAF After Rate Design	2018 Inclusive of SLAF After Rate Design	2019 Inclusive of SLAF After Rate Design	OEB Approved Range
Residential	101.47%	101.30%	102.14%	101.09%	85%-115%
GS < 50kW	98.87%	99.01%	100.85%	98.66%	80%-120%
GS > 50 to 4999kW	94.92%	96.16%	92.84%	97.64%	80%-120%
Standby	74.16%	73.23%	73.55%	73.91%	80%-120%
LU (1)	113.50%	113.35%	112.49%	111.40%	85%-115%
LU (2)	86.53%	85.00%	91.63%	96.27%	85%-115%
Sentinel Lights	95.02%	93.57%	92.86%	91.78%	80%-120%
Street Lighting	120.00%	113.33%	106.66%	100.00%	80%-120%
Unmetered and Scattered Load	114.42%	114.34%	114.96%	114.60%	80%-120%

RATE DESIGN FOR RESIDENTIAL ELECTRICITY CONSUMERS

The New Distribution Rate Design for Residential customers, issued by the OEB on April 2, 2015, confirmed that rates for Residential customers will be migrated to a fixed monthly distribution charge over a four-year transition period commencing in 2016 and ending in 2019.

The Board directed that "*Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral*."

Horizon Utilities incorporated the first year transition adjustment in its proposed rates for 2016 in a manner consistent with OEB policy. As per the Decision Order for the 2016 Annual Filing:

"The OEB finds that Horizon has correctly implemented the OEB's policy on distribution rate design for residential customers. The OEB expects that all distributors will transition to fixed rates in equal increments over a four- year period."

Horizon Utilities incorporated the second year transition adjustment in its proposed rates for 2017 in a manner consistent with OEB policy. As per the Decision Order for the 2017 annual filing, the Board approved the proposed increase in the fixed distribution rate and corresponding decrease in the variable distribution rate for the residential class in 2017.

Alectra Utilities incorporated the third year transition adjustment for the Horizon Utilities RZ in its proposed rates for 2018 in a manner consistent with OEB policy. As per the Decision and Order for the 2018 annual filing, the Board approved the proposed increase in the fixed distribution rate and corresponding decrease in the variable distribution rate for the residential class in 2018.

Alectra Utilities has incorporated the final year transition adjustment for the Horizon Utilities RZ in its proposed rates for 2019. The Residential portion of the proposed 2019 base revenue requirement to which the new distribution rate design applies is $72,950,464 as identified in Table 11, below.

Table 11 – Base Revenue Requirement by Rate Class – Horizon Utilities RZ

Rate Class	2019 Proposed Base Revenue Requirement
Residential	$72,950,464
GS < 50kW	$15,951,947
GS > 50 to 4999kW	$22,528,215
Standby	$856,377
LU (1)	$2,562,709
LU (2)	$1,070,536
Sentinel Lights	$41,404
Street Lighting	$1,788,560
Unmetered and Scattered Load	$451,900
Total	**$118,202,113**

Alectra Utilities has completed Appendix 2-PA for 2019 issued by the Board on July 16, 2015. As identified in Table 12 below, Alectra Utilities' fully fixed charge in 2019 for Residential customers for the Horizon Utilities RZ is $26.69/month, exclusive of annual adjustments in 2019. This indicative fixed charge is based on Alectra Utilities' 2019 base revenue requirement for the Horizon Utilities RZ of $118,202,113 and the 2019 Residential customer count of 227,762 for the Horizon Utilities RZ, as approved in Horizon Utilities Custom IR Application. For purposes of Rate Design, Alectra Utilities has used the fixed/variable percentage as calculated in 2-PA for the Horizon Utilities RZ for the derivation of Residential fixed and variable distribution rates. Alectra Utilities has calculated the 2019 distribution rates for all other rate classes using the normal formulaic derivation for the Horizon Utilities RZ.

1 **Table 12 – Appendix 2-PA – 2019 – New Rate Design Policy for Residential Customers –**
2 **Horizon Utilities RZ**

A) Data Inputs

Test Year Billing Determinants for Residential Class	
Customers	227,762
kWh	1,652,719,193

Proposed Residential Class Specific Revenue Requirement[1]	$ 72,950,464

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	23.67
Distribution Volumetric Rate ($/kWh)	0.004

B) Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	23.67	227,762	$ 64,693,643	90.73%
Variable	0.004	1,652,719,193	$ 6,610,877	9.27%
TOTAL	-	-	$ 71,304,520	-

C) Calculating Test Year Base Rates

Number of Required Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 66,186,987	24.22	$ 66,196,875
Variable	$ 6,763,478	0.0041	$ 6,776,149
TOTAL	$ 72,950,464	-	$ 72,973,024

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 72,950,464	26.69	$ 72,947,754
Variable	0.00%	$ -	0.0000	$ -
TOTAL	-	$ 72,950,464	-	$ 72,947,754

Checks[3]	
Change in Fixed Rate	$ 2.47
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	-$ 2,711
	0.00%

Notes:

1 The final residential class specific revenue requirement, as shown in Appendix 2-P, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 Default number of transition years for rate design policy change is 4. Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Distribution and Total Bill Impacts

The Board instructed distributors that, for the purposes of implementing the new fixed rate design, a 10% test will be applied to customers who consume much less electricity than the typical residential customers. This will allow any mitigation plans to be tailored to those customers who use the least power and whose bills will likely increase due to the shift in the fixed rates. If a customer at the 10th consumption percentile level of electricity has a bill impact of 10% or higher, the distributor must make a proposal for a rate mitigation plan.

Alectra Utilities confirms that for the Horizon Utilities RZ the Residential monthly service charge increase of $3.02 is below the threshold of $4 per month identified in the Board's policy. Accordingly, rate mitigation is not necessary since a customer at the lowest decile of electricity consumption will not have a bill impact of 10% or higher.

Alectra Utilities has followed the Board's direction to assess the combined effect of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service by evaluating the total bill impact for a residential customer at Horizon RZ's 10th consumption percentile. The following is a description of the method Alectra Utilities used to derive the 10th consumption percentile for the Horizon RZ:

1. Alectra Utilities calculated the number of active residential customers who consumed electricity at the location for a minimum of twelve months during the January 1, 2017 to December 31, 2017 period for the Horizon Utilities RZ. The query produced 190,841 records.
2. Alectra Utilities calculated the customer specific average daily consumption for the Horizon Utilities RZ (total usage for the twelve-month period divided by number of billing days in the twelve-month period) to obtain the average daily usage.
3. Alectra Utilities calculated average monthly usage by multiplying the average daily usage by 30 days for the Horizon Utilities RZ.
4. Alectra Utilities calculated the number of monthly kWhs at the 10th consumption percentile for the Horizon Utilities RZ, at 207 kWh.

Alectra Utilities has provided the bill impact for a Residential customer that consumes 207 kWh monthly for the Horizon Utilities RZ in Table 13, below. The monthly service charge increased by $3.02 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 3.21%.

1 **Table 13 – 10th Consumption Percentile Residential Customer Bill Impact (207 kWh) – Horizon Utilities RZ**

Customer Class:	**RESIDENTIAL**
RPP / Non-RPP:	**RPP**
Consumption	**207** kWh
Demand	**-** kW
Current Loss Factor	**1.0379**
Proposed/Approved Loss Factor	**1.0379**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	**$ 23.67**	1	$23.67	**$ 26.69**	1	$26.69	$ 3.02	12.76%
Distribution Volumetric Rate	**$ 0.0040**	207	$ 0.83	**$ -**	207	$ -	$ (0.83)	-100.00%
Fixed Rate Riders	**$ (0.13)**	1	$ (0.13)	**$ (0.34)**	1	$ (0.34)	$ (0.21)	161.54%
Volumetric Rate Riders	**$ 0.0003**	207	$ 0.07	**$ 0.0005**	207	$ 0.11	$ 0.04	58.42%
Sub-Total A (excluding pass through)			**$24.44**			**$26.46**	**$ 2.02**	**8.28%**
Line Losses on Cost of Power	**$ 0.0820**	8	$ 0.64	**$ 0.0820**	8	$ 0.64	$ -	0.00%
Total Deferral/Variance Account Rate Riders	**-$ 0.0006**	207	$ (0.13)	**-$0.00273**	207	$ (0.56)	$ (0.44)	350.14%
GA Rate Riders	**-$ 0.0029**		$ -	**-$ 0.0013**		$ -	$ -	
Low Voltage Service Charge	**$0.00006**	207	$ 0.01	**$0.00006**	207	$ 0.01	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ 0.57**	1	$ 0.57	**$ 0.57**	1	$ 0.57	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$25.54**			**$27.12**	**$ 1.58**	**6.20%**
RTSR - Network	**$ 0.0074**	215	$ 1.60	**$ 0.0072**	215	$ 1.55	$ (0.05)	-2.82%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0068**	215	$ 1.47	**$ 0.0066**	215	$ 1.42	$ (0.04)	-2.87%
Sub-Total C - Delivery (including Sub-Total B)			**$28.60**			**$30.10**	**$ 1.50**	**5.23%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	215	$ 0.77	**$ 0.0036**	215	$ 0.77	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	215	$ 0.06	**$ 0.0003**	215	$ 0.06	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			$ -			$ -	$ -	
TOU - Off Peak	**$ 0.0650**	135	$ 8.75	**$ 0.0650**	135	$ 8.75	$ -	0.00%
TOU - Mid Peak	**$ 0.0940**	35	$ 3.31	**$ 0.0940**	35	$ 3.31	$ -	0.00%
TOU - On Peak	**$ 0.1320**	37	$ 4.92	**$ 0.1320**	37	$ 4.92	$ -	0.00%
Total Bill on TOU (before Taxes)			**$46.66**			**$48.16**	**$ 1.50**	**3.21%**
HST	13%		$ 6.07	13%		$ 6.26	$ 0.19	3.21%
8% Provincial Rebate	-8%		$ (3.73)	-8%		$ (3.85)	$ (0.12)	3.21%
Total Bill on TOU			**$49.00**			**$50.57**	**$ 1.57**	**3.21%**

2

SUMMARY OF ADJUSTMENTS TO THE REVENUE REQUIREMENT

The revenue requirement has been adjusted to incorporate (i) changes to the Working Capital Allowance portion of rate base as a result of changes to Cost of Power flow-through costs; and (ii) changes to the revenue requirement as a result of changes to the Cost of Capital parameters.

The updated Cost of Power amounts incorporate (i) the RPP price increase effective May 1, 2018; (ii) Hydro One 2018 UTRs and 2017 STRs approved by the OEB February 1, 2018 and December 21, 2016, respectively; (iii) an update to the Alectra Utilities demand for the Horizon Utilities RZ from 2016 to 2017 actuals in the RTSR model; (iv) an update to the SME charge as a result of an update to the number of customers and change in the SME rate from $0.79/month to $0.57/month; (v) a change in the ratio of RPP to non-RPP volumes; and (vi) a decrease in the Wholesale Market Service Rate of $0.0008/kWh from $0.0044/kWh to $0.0036/kWh as approved by the OEB on November 2015; and (vii) a decrease in the RRRP Charge from $0.0021/kWh to $0.0003/kWh approved by the OEB on June 22, 2017.

A summary of the changes to the Cost of Power is provided in Table 14 below.

Table 14 – Cost of Power 2019 Annual Filing vs. Custom IR – Horizon Utilities RZ

Category	2019 Annual Filing	2019 Custom IR (EB-2014-0002)	Variance	% Variance
Power	$239,887,129	$308,112,014	($68,224,885)	(22.14%)
Global Adjustment	$265,778,593	$198,764,737	$67,013,856	33.72%
Wholesale Market Services	$19,284,410	$28,184,907	($8,900,497)	(31.58%)
Network	$32,904,999	$41,062,981	($8,157,982)	(19.87%)
Connection	$34,783,293	$30,945,137	$3,838,156	12.40%
Low Voltage	$314,267	$314,684	($416)	(0.13%)
Smart Meter Entity	$1,667,941	$0	$1,667,941	0.00%
TOTAL	**$594,620,633**	**$607,384,461**	**($12,763,828)**	**(2.10%)**

The Cost of Power has decreased $12,763,828, with a corresponding decrease of $110,939 to revenue requirement, as identified in Table 15, below.

Table 15 – Impact to Revenue Requirement due to Cost of Power Update – Horizon Utilities RZ

Description	%	Amount
Cost of Power Increase		($12,763,828)
Increase to Working Capital/Rate Base	12.00%	($1,531,659)
Rate Base Breakdown		
Short Term Debt Increase	4.00%	($61,266)
Long Term Debt Increase	56.00%	($857,729)
Equity Increase	40.00%	($612,664)
Revenue Requirement Components		
Deemed Interest - Short Term Debt	2.16%	($1,323)
Deemed Interest - Long Term Debt	3.74%	($32,095)
Return on Equity	9.30%	($56,978)
PILs Gross-Up	26.50%	($20,543)
Total Revenue Requirement Decrease	**7.24%**	**($110,939)**

Revenue requirement has also been updated from Horizon Utilities' Custom IR Application to incorporate the Cost of Capital parameters issued by the Board on November 23, 2017. Alectra Utilities will make a subsequent update for the updated Cost of Capital parameters for the Horizon Utilities RZ, which are expected to be available prior to the Board rendering its Decision on this Annual Filing. Revenue requirement has decreased by $878,366 as a result of the change in Cost of Capital parameters as identified in Table 16, below.

Table 16 – Impact to Revenue Requirement due to Update of Cost of Capital Parameters – Horizon Utilities RZ

Description	%	2019 Custom IR Application EB-2014-0002	%	2019 Annual Filing After COP Update	%	2019 Annual Filing After COP and COC Parameter Update	Increase/ (Decrease) in Revenue Requirement due to Cost of Power Update	Increase/ (Decrease) in Revenue Requirement due to Cost of Capital Parameters
Rate Base		$557,229,610		$555,697,950		$555,697,950	($1,531,659)	$0
Rate Base Breakdown								
Short Term Debt	4.00%	$22,289,184	4.00%	$22,227,918	4.00%	$22,227,918	($61,266)	$0
Long Term Debt	56.00%	$312,048,581	56.00%	$311,190,852	56.00%	$311,190,852	($857,729)	$0
Deemed Equity	40.00%	$222,891,844	40.00%	$222,279,180	40.00%	$222,279,180	($612,664)	$0
Revenue Requirement Components								
Deemed Interest - Short Term Debt	2.16%	$481,446	2.16%	$480,123	2.29%	$509,019	($1,323)	$28,896
Deemed Interest - Long Term Debt	3.74%	$11,676,468	3.74%	$11,644,373	3.74%	$11,644,373	($32,095)	$0
Return on Equity	9.30%	$20,728,941	9.30%	$20,671,964	9.00%	$20,005,126	($56,978)	($666,838)
PILs Gross-Up	26.50%	$7,473,700	26.50%	$7,453,157	26.50%	$7,212,733	($20,543)	($240,424)
Total Revenue Requirement Impact	**7.24%**	**$40,360,556**	**7.24%**	**$40,249,616**	**7.09%**	**$39,371,251**	**($110,939)**	**($878,366)**

Table 17 below identifies the significant changes in the revenue requirement proposed for 2019 in this Annual Filing, as compared to that which was approved in Horizon Utilities' Custom IR Application. The net impact of the change to the Cost of Power (decrease of $110,939) and the Cost of Capital Parameters (decrease of $878,366) is a decrease to revenue requirement of $989,305.

Table 17 - 2019 Summary of Significant Changes – Horizon Utilities RZ

2019 Summary of Significant Changes							
Note	**Description**		**Custom IR EB-2014-0002**		**Changes**		**2019 Annual Filing EB-2018-0016**
Rate Base:							
	Average Net Fixed Assets	$	476,716,587	$	-	$	476,716,587
1	Working Capital Base	$	670,941,854	$	(12,763,828)	$	658,178,026
	Working Capital Factor		12.00%		0.00%		12.00%
2	Working Capital Allowance	$	80,513,023	$	(1,531,659)	$	78,981,363
	Total Rate Base	**$**	**557,229,610**	**$**	**(1,531,659)**	**$**	**555,697,950**
Revenue Requirement:							
3	Deemed Interest on Debt	$	12,157,914	$	(4,522)	$	12,153,392
4	Return on Equity (ROE)	$	20,728,941	$	(723,815)	$	20,005,126
	Total Return on Rate Base	**$**	**32,886,856**	**$**	**(728,337)**	**$**	**32,158,518**
	Depreciation	$	25,278,432	$	-	$	25,278,432
	OM&A	$	63,238,783	$	-	$	63,238,783
	Property Tax	$	318,611	$	-	$	318,611
5	PILs	$	3,422,636	$	(260,967)	$	3,161,668
Service Revenue Requirement		**$**	**125,145,317**	**$**	**(989,305)**	**$**	**124,156,012**
7	Revenue Offsets	$	5,866,199	$	-	$	5,866,199
Base Revenue Requirement		**$**	**119,279,118**	**$**	**(989,305)**	**$**	**118,289,813**

Notes	
1	The change in working capital base is the result of updates to the Cost of Power flow-through costs: (i) the RPP price reductions based on the OEB's Regulated Price Plan Supply Cost Report, issued April 19, 2018; (ii) Hydro One 2018 UTRs approved by the OEB February 1, 2018; (iii) an update to Horizon Utilities RZ demand from 2016 to 2017 actuals in the RTSR model; (iv) an update to the SME Charge to $0.57 effective January 1, 2018 approved by the OEB March 1, 2018 and an update to the number of customers; (v) a change in the ratio of RPP to non-RPP volumes; vi) a decrease in the Wholesale Market Service Rate of $0.0008/kWh from $0.0044/kWh to $0.0036/kWh as approved by the OEB on November 2015; and (vii) a decrease in the RRRP rate from $0.0021/kWh to $0.0003/kWh as approved by the OEB on June 22, 2017.
2	The change in working capital allowance is due to the change in working capital base as a result of changes to Cost of Power flow-through costs.
3	The change in deemed interest on debt is due to the change in working capital base as a result of changes to Cost of Power flow-through costs; and an increase in the deemed short term debt rate from 2.16% to 2.29%.
4	The change in return on equity is due to the change in the return on equity from 9.3% to 9.00% and a change in working capital base as a result of changes to Cost of Power flow-through costs.
5	The change in PILs is due to the change in the Cost of Capital Parameters and a change in working capital base as a result of changes to Cost of Power flow-through costs.

EARNINGS SHARING MECHANISM

Alectra Utilities reports on its results for 2017 for the Horizon Utilities RZ in this annual filing, the third year for which the ESM is in place. The 2017 regulatory net income and ROE have been calculated in accordance with the Settlement Agreement.

Alectra Utilities moved quickly to operate and report as one company in 2017, consistent with the OEB's direction in the MAADs decision. Alectra Utilities is able to track distribution revenue and the majority of other revenues and certain costs by rate zone, however operating costs, general plant, taxes and other costs cannot be attributed to a specific rate zone, and therefore requires an allocation methodology to allocate costs and revenues to rate zones for the purpose of the ESM calculation.The supporting details for the ESM calculation including the related cost category and allocation methodology are provided in sections a to d below.

To determine regulatory net income, rate base and ROE for the Horizon Utilities RZ, total net income was calculated for the Horizon Utilities RZ; this included amounts for Horizon Utilities for the 1 month ending January 31, 2017, and Horizon Utilities RZ's share of Alectra Utilities' audited financials for the 11 months ending December 31, 2017.

The regulatory net income for Horizon Utilities for the 1 month ending January 31, 2017 has been reconciled with the financial statements for Horizon Utilities - 1 month ended January 31, 2017.

Alectra Utilities' 2017 (11 months) regulatory net income reported in RRR 2.1.7 and filed with the OEB has been reconciled with the financial statements for Alectra Utilities - 11 months ended December 31, 2017.

The methodology used to calculate Horizon Utilities RZ's share of Alectra Utilities' 2017 financial data is described further in sections (c) Horizon Utilities RZ 2017 Rate Base and (d) Horizon Utilities RZ 2017 Regulatory Net Income.

In the OEB's Decision in Alectra Utilities' 2018 EDR Application (EB-2017-0024),issued on April 5, 2018 (revised April 6, 2018), the OEB stated that: "*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.*

As directed by the Board in its Decision, the impact of the capitalization policy change has been addressed through the ESM. Alectra Utilities has not adjusted earnings based on Horizon Utilities capitalization policy in place prior to the merger.

Table 18 – Summary of ESM Calculation – Horizon Utilities RZ

2017 Regulatory ROE for ESM	2017 Actuals ESM	Annual Filing EB-2016-0077	Variance
Adjusted Regulatory net income	$ 19,807,963	$ 18,281,100	$ 1,526,863
Deemed equity	$ 207,042,402	$ 208,212,985	($ 1,170,584)
ROE	9.567%	8.780%	0.787%
% Return in excess of approved in rates		0.787%	
$ Return in excess of approved in rates		$1,629,640	
Amount payable to rate payers		$814,820	

The regulatory net income for the purposes of earnings sharing result in an achieved ROE of 9.567%, as identified in Table 18 above. Alectra Utilities' approved ROE for the Horizon Utilities RZ for 2017 was 8.78%. Alectra Utilities' incurred earnings are $1,629,640 higher than the 2017 approved ROE with $814,820 to be returned to ratepayers.

Table 19 below shows the calculation of the 2017 ESM rate riders to refund the ESM amount of $814,820 to ratepayers.

Table 19 – Proposed Rate Riders to Dispose of Earnings Sharing Amount – Horizon Utilities RZ

Rate Class	Total $	Fixed Rate Rider	Variable Rate Rider	Variable Units
Residential	($ 501,429)	($ 0.18)	$ 0.0000	$/kWh
General Service Less Than 50 kW	($ 109,825)	($ 0.29)	($ 0.0001)	$/kWh
General Service > 50 kW	($ 165,279)	($ 2.67)	($ 0.0180)	$/kW
Large Use 1	($ 17,617)	($ 166.82)	($ 0.0098)	$/kW
Large Use 2	($ 7,341)	($ 39.46)	($ 0.0023)	$/kW
Unmetered Scattered Load	($ 2,289)	($ 0.06)	($ 0.0001)	$/kWh
Sentinel Lighting	($ 224)	($ 0.04)	($ 0.1058)	$/kW
Street Lighting	($ 10,817)	($ 0.01)	($ 0.0374)	$/kW
Total	**($ 814,820)**			

The ESM rate rider model is filed as Attachment 11. A live excel version will also be provided as part of this filing.

The 2017 Actual ESM regulatory net income and deemed equity have been adjusted in accordance with the OEB's guidance for 2.1.5.6 and the Settlement Agreement, as discussed below. The approved 2017 Annual Filing EB-2016-0077 amounts are without adjustment.

Alectra Utilities seeks approval for the calculation of the Horizon Utilities RZ's 2017 achieved ROE of 9.567%, net income of $19,807,963, excess earnings of $1,629,640 and amount due to rate payers of $814,820 for the purposes of earnings sharing as identified in Table 19, above.

(a) Regulatory Net Income for ESM

Table 20 below shows the calculation of regulatory net income starting with the 2017 regulatory net income for the Horizon Utilities RZ and adjustments required for purposes of the OEB ROE calculation and the Settlement Agreement.

Table 20 – Calculation of Regulatory Net Income – Horizon Utilities RZ

	2017 Actuals			Annual Filing
2017 Regulatory ROE	Horizon Utilities	Alectra Utilities	Total	EB-2017-0024
Regulated net income (loss) per RRR 2.1.7	**$ 1,325,637**	**$ 77,029,538**	**$ 78,355,174**	**$ 22,974,211**
Remove CDM Net income	$ 0	($ 949,339)	($ 949,339)	
Remove renewable generation (income) loss	$ 0	$ 12,468,382	$ 12,468,382	
Remove merger costs	$ 482,892	$ 2,032,671	$ 2,515,563	
Add actual interest cost	$ 642,098	$ 51,910,112	$ 52,552,210	
Deduct income tax expense	$ 423,562	$ 10,501,164	$ 10,924,726	
Remove share of Joint venture net income		($ 559,101)	($ 559,101)	
Deduct other rate zones regulatory net income before interest and taxes		($ 121,366,548)	($ 121,366,548)	
Horizon Utilities Rate Zone regulatory net income before interest and taxes	**$ 2,874,189**	**$ 31,066,879**	**$ 33,941,068**	**$ 22,974,211**
Deemed interest expense - short term			($ 364,395)	
Deemed interest expense - long term			($ 10,061,933)	
Regulatory Net Income before Tax			**$ 23,514,740**	**$ 22,974,211**
Income taxes/PILs - current			($ 3,388,383)	($ 4,693,111)
Horizon Utilities Rate Zone regulatory net income before ESM adjustments			**$ 20,126,357**	**$ 18,281,100**

Adjusted Net Income for ESM	**2017 Actuals ESM**
Regulatory Net income	$ 20,126,357
Add back taxes	$ 3,388,383
Add back 2017 ESM accrual	$ 985,377
Add non-allowable donations (non-LEAP)	$ 3,897
Remove DVA interest (income) expense	$ 43,834
Adjustment for 2016 ESM actual vs. accrued	$ 33,508
Deduct ROE on Stranded meters	($ 84,000)
Deduct 1/5th of Application costs	($ 495,385)
Adjusted NIBT for ESM	**$ 24,001,971**
PILS	$ 4,194,008
Adjusted Net Income for ESM	**$ 19,807,963**

The 2017 regulatory net income reported by Alectra Utilities for the Horizon Utilities RZ was $20,126,357, as identified in Table 20. The 2017 regulatory net income is based on RRR MIFRS.

The bottom part of Table 20 shows the adjustments made to the regulatory net income to determine regulatory net income after tax of $19,807,963 reported on the same basis as 2.1.5.6 and for the purposes of earnings sharing.

Adjustments to the regulatory net income reported on the same basis as RRR 2.1.5.6 attributable to the Horizon Utilities RZ, in order to determine regulatory net income for the purposes of earnings sharing, are as follows:

- Exclude the 2017 ESM accrual included in the regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Exclude net interest expense on deferral and variance accounts;
- Exclude the 2016 ESM expense recorded in the 2017 regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Exclude the Rate of Return on Stranded Meters at the short term debt rate of 1.76%;
- Include one-time costs incurred for Horizon Utilities' Custom IR Application, calculated as one-fifth of $2,476,925 in each of 2015 through 2019; and
- Recalculate PILs to reflect the adjusted net income as a result of any revenue and expense adjustments.

These adjusting revenue and expense items were approved on page 30 of Horizon Utilities' Settlement Agreement for its Custom IR Application.

Alectra Utilities has also made the following adjustment for the Horizon Utilities RZ:

- Included current tax on the stranded meter recovery as approved on page 41 of the Settlement Proposal. Current tax on the stranded meter recovery was included in the calculation of PILs in the Custom IR Application.

Specifically, the 2017 regulatory net income reported in RRR 2.1.7 has been adjusted for:

(i) revenue and expense items prescribed by the OEB for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband; and (ii) revenue and expense items specifically included or excluded for the purposes of earnings sharing.

Regulatory net income for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband is reported in RRR 2.1.5.6. Adjustments to the regulatory net income reported in RRR 2.1.7 in order to determine regulatory net income for RRR 2.1.5.6 are as follows:

- Exclude merger related costs, consistent with the calculation of ROE in Horizon Utilities' Custom IR Application. These costs are also excluded from regulatory net income reported in RRR 2.1.5.6.
- Exclude 2016 ESM costs included in 2017 costs due to differences between the accrual and final amount;
- Exclude net interest revenue/expense on Deferral and Variance Accounts (DVAs). Interest revenues and expenses related to DVAs were not included in the calculation of ROE in Horizon Utilities' Custom IR Application;
- Exclude non-rate regulated items not approved in the distributor's last cost of service application. Alectra Utilities has excluded non-LEAP donations of $3,784 from the regulatory net income reported in RRR 2.1.5.6;
- Calculate the cost of debt based on the deemed debt ratio of 56% long term debt and 4% short term debt; and the Cost of Capital parameters approved in Horizon Utilities' 2017 Annual Filing; and
- PILs shall be recalculated from actual to reflect the adjusted net income as a result of any revenue and expense adjustments. A reconciliation of current income tax is provided in Table 21 below. Additionally, the regulatory net income for the purposes of the ESM calculations incorporates current tax only (i.e. excludes deferred taxes) which is consistent with the PILs calculation in Horizon Utilities' Custom IR Application.

Table 21 – Calculation of Current Taxes – Horizon Utilities RZ

Adjustments	Income before Tax	Current Tax Impact	Tax Rate
Regulatory Net income	$ 23,514,740	$ 3,388,383	14.41%
Add back 2017 ESM accrual	$ 985,377	$ 261,125	26.50%
Add non-allowable donations (non-LEAP)	$ 3,897	$ 1,033	26.50%
Adjustments for DVA interest (income) expense	$ 43,834	$ 11,616	
Adjustment for 2016 ESM actual vs. accrued	$ 33,508	$ 8,880	26.50%
Deduct ROE on Stranded meters	($ 84,000)	($ 22,260)	26.50%
Record Tax on Stranded Meter Rate Rider as per Custom IR Application		$ 676,509	
Deduct 1/5th of Application costs	($ 495,385)	($ 131,277)	26.50%
Adjusted NIBT for ESM	**$ 24,001,971**	**$ 4,194,008**	**17.47%**

(b) Deemed Equity for ESM

The calculation of deemed equity used to determine the ROE is 40% of rate base. Table 22 below uses the rate base amount to calculate the deemed short term debt, long term debt and equity based on the deemed debt equity structure underpinning Horizon Utilities 2017 approved distribution rates.

Table 22 – Calculation of Deemed Debt and Equity – Horizon Utilities RZ

Deemed Debt and Equity	%	2017 Actuals ESM	Annual Filing EB-2016-0077	Variance
Deemed ST Debt	4.00%	$ 20,704,240	$ 20,821,299	($ 117,058)
Deemed LT Debt	56.00%	$ 289,859,362	$ 291,498,179	($ 1,638,817)
Deemed Equity	40.00%	$ 207,042,402	$ 208,212,985	($ 1,170,584)
Total Rate Base	100.00%	**$ 517,606,004**	**$ 520,532,463**	**($ 2,926,459)**

Rate base excludes stranded meter assets and work-in-progress consistent with Horizon Utilities' 2017 rate application. The calculation of rate base is discussed in the Horizon Utilities RZ Rate Base section, below.

(c) 2017 Rate Base - Horizon Utilities RZ

The calculation of Horizon Utilities RZ rate base is shown in Table 23 below.

Table 23 – Calculation of Rate Base – Horizon Utilities RZ

Rate Base	2017 Actuals ESM	Annual Filing EB-2016-0077	Variance
Average Net Fixed Assets	**$ 449,067,999**	**$ 432,973,917**	**$ 16,094,082**
Working Capital Allowance:			
Cost of Power	$ 510,177,988	$ 667,926,057	**($ 157,748,069)**
Controllable expenses	$ 60,972,051	$ 61,728,494	**($ 756,443)**
Working Capital Base	$ 571,150,039	$ 729,654,551	**($ 158,504,512)**
Working Capital Allowance	**$ 68,538,005**	**$ 87,558,546**	**($ 19,020,541)**
Rate Base	**$ 517,606,004**	**$ 520,532,463**	**($ 2,926,459)**

The average net fixed assets amount is the average of the opening and closing in-service property, plant and equipment ("PP&E"), excluding stranded meters, work-in-progress and non-distribution assets, as summarized in Table 24.

Table 24 – Calculation of Average Net Fixed Assets – Horizon Utilities RZ

Description	January 1, 2017	December 31, 2017	Average
Distribution Assets	$ 393,011,067	$ 422,396,256	$ 407,703,662
General Plant	$ 43,380,554	$ 39,348,121	$ 41,364,337
Total	**$ 436,391,621**	**$ 461,744,377**	**$ 449,067,999**

The January 1, 2017 opening PP&E is equal to the 2016 closing PP&E as filed in the Alectra Utilities' 2018 EDR Application (EB-2017-0024).

The December 31, 2017 closing PP&E is derived from Alectra's Fixed Asset Continuity Schedules. Alectra continues to maintain four separate legacy accounting systems including fixed asset records. Distribution plant ("DP") is physically located in the rate zone and at December 31, 2017, the DP in the Horizon Utilities rate zone was $422,396,256.

General plant ("GP") is not identifiable by rate zone and GP assets support the operations of all rate zones. The recording of GP additions in 2017 were recorded in the general ledgers and fixed asset records of the various rate zones based on the legacy system used by the employees processing the transactions and not based on use by rate zone.

The total Alectra Utilities December 31, 2017 GP net book value was allocated to the rate zones based on the ratio of 2016 net book value of general plant for each rate zone to the total. Adjustments were made to remove merger impacts.

Cost of Power ("COP") is the actual amount for the Horizon Utilities RZ. At December 31, 2017, Alectra Utilties had four separate billing systems, one for each rate zone. Alectra Utilities continues to track energy sales and COP by rate zone. Energy Sales and Cost of Power amounts were determined in accordance with the OEB's guidance on the recording of retail settlement variances.

Controllable expenses are equal to the Horizon Utilities RZ's OM&A consistent with the 2017 rate filing. Horizon Utilities RZ's OM&A is discussed in section (d) below.

(d) Horizon Utilities RZ 2017 Regulatory Net Income

The Horizon Utilities RZ 2017 regulatory net income is the sum of Horizon Utilities' regulatory net income for the one month ending January 31, 2017 ("stub period") plus its portion of the Alectra Utilities regulatory net income for the 11 months ending December 31, 2017.

Table 25 below summarizes the combination of the stub period plus the Horizon Utilities RZ's share of the Alectra Utilities amounts to arrive at the Horizon Utilities RZ 2017 net income.

Determining the regulatory net income for the Horizon Utilities RZ required a review of the Alectra Utilities financial amounts to identify which items are directly attributable to the rate zones and those that need to be allocated amongst rate zones. This process is described below for each line item contributing to Regulatory net income

Table 25 – 2017 Regulatory Net Income – Horizon Utilities RZ

Regulatory Net Income	2017 Actual 1 Month ending Jan 31/17	11 Months ending Dec 31/17	Total
Distribution revenue	$ 9,593,782	$ 103,901,260	$ 113,495,042
Other revenue	$ 508,612	$ 4,791,551	$ 5,300,164
Revenue	**$ 10,102,394**	**$ 108,692,811**	**$ 118,795,206**
OM&A	$ 5,266,751	$ 55,705,300	$ 60,972,051
Depreciation	$ 1,961,455	$ 21,920,632	$ 23,882,087
Net Income before interest and tax	**$ 2,874,188**	**$ 31,066,880**	**$ 33,941,068**
Deemed interest on ST Debt	$ 30,949	$ 333,446	$ 364,395
Deemed interest on LT Debt	$ 854,575	$ 9,207,358	$ 10,061,933
Regulatory Net Income before Tax	**$ 1,988,664**	**$ 21,526,076**	**$ 23,514,740**
PILS	$ 423,562	$ 2,964,821	$ 3,388,383
Regulatory Net income	**$ 1,565,102**	**$ 18,561,255**	**$ 20,126,357**

(1) Distribution revenue consists of actual distribution revenues from the Horizon Utilities RZ customers for the entire year.

(2) Other revenue for the stub period is the actual for the Horizon Utilities RZ. Other revenue consists mainly of rate zone specific revenues such as specific service and cost recoveries. For the Alectra Utilities period, the other revenues recorded by each rate zone were reviewed to identify the rate zone specific items and to reallocate the cost recoveries to offset OM&A. Horizon Utilities RZ 2017 rates were based on a reallocation of management fee revenues from other revenue to offset OM&A. The Horizon Utilities RZ-specific other revenues are included in the 11 month amount in Table 25, above.

(3) Operating expenses for the Alectra Utilities period are not identifiable by rate zone. Alectra Utilities OM&A was allocated to the rate zones based on the reported 2014-2016 premerger legacy actual OM&A amounts adjusted to remove transaction costs.

The allocators were further adjusted to reflect that Alectra Utilities OM&A consists of 11 months for the Horizon Utilities, Enersource and PowerStream rate zones but only 10 months for the Brampton rate zone. These allocators and the resulting percent allocation are show in Table 26, below.

Table 26 – OM&A by Rate Zone Allocators

	Enersource	Horizon Utilities	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,300,996	$60,901,688	$28,658,213	$86,722,101	$232,582,998
Adjust to Alectra Utilities Overhead capitalization	-$ 1,792,000	-$ 6,280,000	$ 2,350,000	-$ 557,000	($6,279,000)
Revised OM&A	**$54,508,996**	**$54,621,688**	**$31,008,213**	**$86,165,101**	**$226,303,998**
% of total	24.09%	24.14%	13.70%	38.07%	100.00%
Prorate for 2017 part year:					
Months	11	11	10	11	
Prorated (Alectra Utilities Overhead basis)	$ 49,966,580	$ 50,069,880	$ 25,840,178	$ 78,984,676	$204,861,313
% of total	**24.39%**	**24.44%**	**12.61%**	**38.56%**	**100.0%**

The Alectra Utilities OM&A for 11 months of 2017 was $233,507,349 which is reflective of the 2017 annual RRR filing and was adjusted to remove non-distribution related amounts. In addition, before the allocation of OM&A to the rate zones, merger costs and specific distribution-related amounts not pertaining to the Horizon Utilities RZ were adjusted, as summarized in Table 27, below.

Table 27 – Adjusted Alectra Utilities OM&A for Allocation to Rate Zones (11 months)

Description	Amount
Alectra Utilities	$233,507,349
Less net merger OM&A costs	($ 2,032,671)
Adjusted Alectra Utilities OM&A for allocation to rate zones	**$231,474,678**
Distribution related adjustments for PRZ and ERZ	($ 3,556,000)
Total for allocation	$ 227,918,678

The adjusted Alectra Utilities OM&A was then allocated to the rate zones, using the allocators from Table 26, resulting in the allocated amounts summarized in Table 28, below.

Table 28 – Allocation of Alectra Utilities OM&A to Rate Zones

LDC/Rate Zone	Alectra Utilities	Allocation %	Allocated Amount	Rate Zone Specific	OM&A by Rate Zone
Brampton		12.61%	$ 28,748,518		$ 28,748,518
Enersource		24.39%	$ 55,590,373	$ 1,153,000	$ 56,743,373
Horizon Utilities		24.44%	$ 55,705,300		$ 55,705,300
PowerStream		38.56%	$ 87,874,487	$ 2,403,000	$ 90,277,487
Alectra Utilities	$ 227,918,678				$ -
Total	**$ 227,918,678**	**100.00%**	**$ 227,918,678**	**$ 3,556,000**	**$ 231,474,678**

(4) Depreciation and amortization is based on the PP&E attributable to the Horizon Utilities RZ as discussed in section (b), above, i.e., actual for the Horizon Utilities RZ for distribution plant for all of 2017, actual for the Horizon Utilities RZ for general plant in the stub period, and an allocation of general plant depreciation expense for the Alectra Utilities period. Derecognition expense relates to distribution plant and is tracked by rate zone; the amounts shown for the Horizon Utilities RZ are actual amounts for the Horizon Utilities RZ. Adjustments were made to remove merger impacts. This is summarized in Table 29, below.

Table 29 – Horizon Utilities Rate Zone Depreciation Expense

Horizon Utilities Rate Zone	Jan 31/17 (1 month)	Dec 31/17 (11 months)	2017 Total
Distribution Assets	$1,306,460	$13,924,861	$15,231,321
General Plant	$589,825	$6,431,099	$7,020,923
subtotal	**$1,896,285**	**$20,355,959**	**$22,252,244**
Derecognition expense	$65,171	$1,564,672	$1,629,843
Total	**$1,961,455**	**$21,920,632**	**$23,882,087**

The 2017 general plant depreciation expense for the Alectra Utilities' period of $29,094,654 net of merger adjustment was allocated to the rate zones based on the ratio of each rate zone`s 2016 general plant depreciation expense to the total for all rate zones. This is shown in Table 30, below.

Table 30 – Alectra Utilities' General Plant Depreciation Allocated to Rate Zones

General Plant Rate Zone	Depreciation Dec 31/16	Alectra Percentage	Depreciation Amount
Horizon Utilities	$7,006,612	22.10%	**$ 6,431,099**
Enersource	$7,487,110	23.62%	$ 6,872,129
Brampton	$2,184,969	6.89%	$ 2,005,499
PowerStream	$15,019,619	47.38%	$ 13,785,928
Total	**$31,698,310**	100.00%	$ 29,094,654

(5) Interest expense is based on the deemed short term and long term debt amounts, discussed above in section (b) at the interest rates underpinning Alectra Utilities' 2017 approved rates for the Horizon Utilities RZ.

(6) Income tax expense

The Horizon Utilities RZ 2017 (11 months) regulatory net income before taxes of $21,526,076 from Table 25 above was adjusted by Horizon Utilities RZ's share of Alectra Utilities adjustments for tax resulting in taxable income of $11,387,071. Using the tax rate of 26.5% and actual tax credits of $52,573 related to the Horizon Utilities RZ results in current income tax expense of $2,964,821 as shown in Table 31, below.

1 **Table 31 – Adjustments to Determine Horizon Utilities Rate Zone Taxable Income**

Horizon Rate Zone - Alectra period	Actual	EB-2016-0077
Regulatory net income before tax	$ 21,526,076	$ 18,281,100
Net additions (deductions) for tax	($ 10,139,005)	($ 4,675,679)
Taxable income	$ 11,387,071	$ 13,605,421
Rate rate	26.50%	26.50%
Income taxes	$ 3,017,574	$ 3,605,437
tax credits	($ 52,753)	($ 156,000)
Current taxes payable	$ 2,964,821	$ 3,449,437
PILs Gross-up	$ 0	$ 1,243,674
Income taxes	$ 2,964,821	$ 4,693,111

2

3 The Horizon Utilities RZ income tax expense for the Alectra Utiltiies period shown in Table 31
4 was added to the income tax expense for the stub period ending Jan 31, 2017, to determine the
5 total Horizon Utilities RZ 2017 income tax expense, as shown in Table 25, above.

Capital Investment Variance Account

Horizon Utilities' 2015 - 2019 Custom IR Settlement Agreement provided for the introduction of a deferral account (1508 Sub-account "Capital Additions Variance Account", referred to in the Settlement Agreement as the Capital Investment Variance Account ("CIVA") to refund to ratepayers any difference in the revenue requirement should in-service capital additions be lower than, or the pacing of capital additions be slower than, forecast over the 2015-2019 period.

The Parties agreed to track variances in the revenue requirement due to variances in the capital budget. Over the term of the plan, if Horizon Utilities spends less than its capital forecast, the reduced revenue requirement impact of this will be returned to customers. The Parties agreed, and the OEB approved, that the CIVA balance would be disposed of following the end of the five-year Custom IR term, if applicable.

Alectra Utilities reports the capital additions for 2017 for the Horizon Utilities RZ in this Annual Filing. As identified in Table 32 below, Horizon Utilities RZ actual capital additions for 2017 were $52,393,539, $6,767,425 higher than the capital additions of $45,626,114 forecast in its Custom IR Application. The 2017 additions are based on Alectra Utilities' overhead capitalization policy, consistent with the OEB's decision (EB-2017-0024), regarding the treatment of overhead capitalization for the Horizon Utilities RZ earnings sharing mechanism calculation.

Table 32 – 2015 to 2017 Capital Additions - Actual vs. Custom IR Application

Capital Additions	Actual	Custom IR Application (EB-2014-0002)	Variance	EDR Application
2015	$ 46,643,216	$ 38,314,524	$ 8,328,692	EB-2016-0077
2016	$ 44,295,265	$ 41,147,533	$ 3,147,732	EB-2017-0024
2017	$ 52,393,539	$ 45,626,114	$ 6,767,425	EB-2018-0016
Cumulative total	**$ 143,332,020**	**$ 125,088,171**	**$ 18,243,849**	

Forecasted capital additions for 2015 to 2017 of $38,314,524, $41,147,533 and $45,626,114 were approved by the Board in Horizon Utilities' Settlement Agreement for its Custom IR Application (refer to Settlement Table 9, page 33).

Horizon Utilities' actual 2015 capital additions of $46,643,216 were approved by the Board in EB-2016-0077 and actual 2016 capital additions of $44,295,265 were approved by the Board in EB-2017-0024.

As shown in Table 32 above, Horizon Utilities RZ capital additions for the years 2015 to 2017 exceed the corresponding amounts approved in its Custom IR Application (EB-2014-0002). Therefore, Alectra Utilities has not established, or made an entry to, the 1508 Sub-account "Capital Investment Variance Account" ("CIVA") for the Horizon Utilities RZ.

Alectra Utilities seeks approval of Horizon Utilities RZ 2017 capital additions of $52,393,539 for the purpose of calculating the 2017 entry to the CIVA. Table 33 below presents the capital additions by rate zone for the legacy stub periods plus the Alectra Utilities total in-service regulatory capital additions of $255,879,336, that along with work-in-progress, forms the additions reported in its RRR 2.1.5.2 Capital filed April 30, 2018.

Table 33 – Alectra Utilities 2017 Actual Capital Additions by Rate Zone

	Brampton	Enersource	Horizon Utilities	PowerStream	Alectra	Total
1) Distribution Plant (DP)						
2017 pre-Alectra	($ 185,718)	$ 162,363	$ 1,239,563	$ 12,014,175		$ 13,230,383
2017 Alectra	$ 24,064,276	$ 52,572,809	$ 45,429,350	$ 103,658,057	$ 225,724,491	$ 225,724,491
Total DP additions	**$ 23,878,558**	**$ 52,735,171**	**$ 46,668,913**	**$ 115,672,232**	**$ 225,724,491**	**$ 238,954,874**
2) General Plant (GP)						
2017 pre-Alectra	$ 66,073	$ 162,363	$ 212,809	$ 891,073		$ 1,332,317
2017 Alectra	$ 4,589,806	$ 8,463,535	$ 5,511,817	$ 11,589,687	$ 30,154,845	$ 30,154,845
Total GP additions	**$ 4,655,878**	**$ 8,625,898**	**$ 5,724,626**	**$ 12,480,760**	**$ 30,154,845**	**$ 31,487,162**
Total new capital additions	**$ 28,534,436**	**$ 61,361,069**	**$ 52,393,539**	**$ 128,152,992**	**$ 255,879,336**	**$ 270,442,036**

Capital additions consist of distribution system plant and general plant additions. Distribution plant is identifiable and tracked by rate zone as these assets are located in and serve a specific rate zone.

General plant consists mainly of facilities, computers, software, office equipment and fleet. These assets support the overall distribution business rather than a particular rate zone. General plant capital additions in 2017 are based on Alectra Utilities overall needs and not based on a specific rate zone.

For purposes of the Alectra Utilities CIVA calculation for the Horizon Utilities RZ, it is necessary to allocate the general plant additions to the rate zones. The purpose of general plant is to support the overall business, thus general plant should be allocated to the rate zones based on the proportion each represents of the overall distribution business. Alectra Utilities has used the 2016 rate base from 2016 ROE filings by the legacy utilities as the allocator that represents the proportion each rate zone is of the total distribution business. This is summarized in Table 34 below.

Table 34 – Rate Zone Proportions based on 2016 Rate Base

	Brampton	Enersource	Horizon	PowerStream	Total
Rate Base from ROE filing	$ 421,744,471	$ 777,690,672	$ 506,465,550	$ 1,064,944,076	$ 2,770,844,769
Proportion	15.2%	28.1%	18.3%	38.4%	100.0%

Alectra Utilities 2017 capital additions for the Horizon Utilities RZ (net of capital contributions) are summarized in Table 35, below. These consist of the directly identifiable distribution plant additions and the general plant additions including the Alectra Utilities additions allocated to the Horizon Utilities RZ.

Table 35 – Horizon Utilities RZ 2017 Capital Additions

Horizon Utilities Rate zone	Capital Additions
DP capital additions	
Jan 1- 31, 2017	$ 1,239,563
Feb 1 - Dec 31, 2017	$ 45,429,350
Total DP additions	**$ 46,668,913**
GP capital additions - January 2017	$ 212,809
Share of Alectra GP additions	$ 5,511,817
Total GP additions	**$ 5,724,626**
Total capital additions	**$52,393,539**

As discussed above, based on the OEB's Decision on Alectra Utilities' 2018 rate application (EB-2017-0046), there has been no adjustment for the change to Alectra Utilities overhead capitalization policy.

Alectra Utilities general plant additions of $30,154,845 have been allocated to the Horizon Utilities RZ in the amount of $5,511,817 based on the 2016 rate base allocator of 18.3% in Table 34 as discussed above.

REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative (*EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met. Consistent with a Letter from the Board to Licensed Electricity Distributors re: *Process for 2015 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*, dated July 25, 2014, distributors may also elect to dispose of Group 1 account balances below the threshold. Additionally, the Board-approved Settlement Agreement in Horizon Utilities' Custom IR Application includes the disposition of Deferral and Variance accounts in the proposed annual recurring adjustments as identified on page 29 of the Settlement Proposal.

Group 1 accounts consist of the following Uniform System of Accounts ("USoA"):

- 1550 - Low Voltage Account;
- 1551 - SME Charge Account;
- 1580 - RSVA Wholesale Market Service Charge Account;
- 1584 - RSVA Retail Transmission Network Charge Account;
- 1586 - RSVA Retail Transmission Connection Charge Account;
- 1588 - RSVA Power Account;
- 1589 - RSVA Global Adjustment Account;
- 1590 - Recovery of Regulatory Asset Balances Account (if applicable); and
- 1595 - Disposition and Recovery/Refund of Regulatory Balances Account.

The Group 1 balances as of December 31, 2017, in the amount of ($16,998,445) have been adjusted for the following items to determine the amount for disposition of ($6,871,097) as identified in Table 36, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition as directed in the OEB's letter dated May 23, 2017 on the "*Guidance on the Disposition of Accounts 1588 and 1589*". For the Horizon Utilities RZ, adjustments of ($1,407,107) and $3,650,554 have been made to Account 1588 and Account 1589 respectively for a total of $2,243,447, to reflect RPP settlement true-up claims for 2017 that were settled in 2018. Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- Only Class B Capacity Based Recovery ("CBR") amounts are to be disposed of through this rate proceeding as directed by the OEB in its *Accounting Guidance on Capacity Based Recovery* issued July 25, 2016; and
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e. the amount for disposition includes 2017 projected carrying charges).

Table 36 – Group 1 Balances for Disposition – Horizon Utilities RZ

Description	Amount
Group 1 Account Balances as of December 31, 2017	**($16,998,445)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers	($7,370,171)
RPP Settlement True-up Claims Adjustment	$2,243,447
Add Projected Carrying Charges	($120,899)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	$634,629
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($6,871,096)**

Alectra Utilities has computed the disposition threshold for the Horizon Utilities RZ, based on the adjusted Group 1 balances to be ($0.0013)/kWh, as identified in Table 37, below. Alectra Utilities requests disposition of its Group 1 account balances in this Annual Filing for the Horizon Utilities RZ.

Table 37 - Calculation of Disposition Threshold – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	$1,152,402
Smart Meter Entity Charge	1551	($52,186)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	($243,732)
RSVA - Wholesale Market Service Charge excluding CBR	1580	($9,199,637)
RSVA - Retail Transmission Network Charge	1584	($726,907)
RSVA - Retail Transmission Connection Charge	1586	$1,395,528
RSVA - Power	1588	($3,124,518)
RSVA - Global Adjustment	1589	($6,153,441)
Disposition and Recovery/Refund of Regulatory Balances	1595	($45,954)
Group 1 Account Balances as of December 31, 2017		**($16,998,445)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers		($7,370,171)
RPP Settlement True-up Claims Adjustment		$2,243,447
Add Projected Carrying Charges		($120,899)
Deduct 1595 Residual Balances to be disposed in a future period		$634,629
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($6,871,097)**
2017 kWhs		5,162,637,449
Threshold Test $/kWh		**($0.0013)**

Alectra Utilities has completed and filed Tabs 3 to 8 of the modified IRM Model as Attachment 6 for the Horizon Utilities RZ. Alectra Utilities has reconciled the Group 1 balances filed in the 2017 RRR, section 2.1.7 for the Horizon Utilities RZ, as identified in Table 38, below. Alectra Utilities confirms that the last Board approved balance of ($7,370,171) for the Horizon Utilities RZ has been transferred to Account 1595 (as identified in Alectra Utilities 2018 EDR Application EB-2017-0024). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2017 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rate of 1.5% for 2018 Q1 and 1.89% for 2018 Q2-Q4 were used to calculate forecasted interest for 2018. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 38 – Deferral and Variance Account Reconciliation – Horizon Utilities RZ

Account Description	Account	Principal Amounts as of Dec 31, 2017	Carrying Charges to Dec 31, 2017	Principal Disposition during 2018 - instructed by Board EB-2017-0024	Interest Disposition during 2018 - instructed by Board EB-2017-0024	Projected Carrying Charges to Dec 31, 2018	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims 2017 Reversal	Projected Carrying Charges to December 31, 2018	1595 Balances Not Claimed in 2019	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	1,139,147	13,255	(552,752)	(9,052)	10,511	601,110				601,110
Smart Meter Entity Charge	1551	(51,637)	(549)	23,673	377	(501)	(28,637)				(28,637)
RSVA - Wholesale Market Service Charge - CBR B	1580	(241,267)	(2,465)	185,940	2,903	(992)	(55,880)				(55,880)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(9,088,082)	(111,555)	4,482,609	74,881	(82,553)	(4,724,700)				(4,724,700)
RSVA - Retail Transmission Network Charge	1584	(720,364)	(6,543)	532,829	4,765	(3,362)	(192,674)				(192,674)
RSVA - Retail Transmission Connection Charge	1586	1,375,343	20,185	(941,983)	(17,806)	7,768	443,506				443,506
RSVA - Power	1588	(3,137,487)	12,969	(671,361)	(22,523)	(68,274)	(3,886,676)	(1,407,107)	(25,222)		(5,319,006)
Sub-total not including RSVA Power Global Adjustment		(10,724,347)	(74,703)	3,058,955	33,546	(137,402)	(7,843,952)	(1,407,107)	(25,222)		(9,276,282)
RSVA - Power Global Adjustment	1589	(6,136,096)	(17,345)	4,813,354	52,992	(23,710)	(1,310,805)	3,650,554	65,436		2,405,185
Total including RSVA Power Global Adjustment		(16,860,443)	(92,049)	7,872,308	86,538	(161,112)	(9,154,757)	2,243,447	40,214		(6,871,097)
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	194,908	393,896	(194,908)	(393,767)		129			129	-
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	(469,217)	(165,541)				(634,759)			(634,759)	-
Total 1595		(274,309)	228,355	(194,908)	(393,767)	-	(634,629)	-	-	(634,629)	-
Total Group 1		**(17,134,752)**	**136,306**	**7,677,400**	**(307,229)**	**(161,112)**	**(9,789,387)**	**2,243,447**	**40,214**	**(634,629)**	**(6,871,097)**
Total Amount for Disposition		**(17,134,752)**	**136,306**	**7,677,400**	**(307,229)**	**(161,112)**	**(9,789,387)**	**2,243,447**	**40,214**	**(634,629)**	**(6,871,097)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Horizon Utilities RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year"*.

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs for the Horizon Utilities RZ. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response ("CBR") Disposition

Alectra Utilities has also established separate rate riders to dispose of the global adjustment ("GA") and the Capacity Based Response ("CBR") account balances for the Horizon Utilities RZ. The GA rate riders are applicable for non-RPP Class B customers only and the CBR rate riders are applicable for Class B customers only. Alectra Utilities' Class A customers for the Horizon Utilities RZ are invoiced actual GA and CBR. Therefore, none of the variance in the GA and CBR account balances should be attributed to these customers.

There were 36 Alectra Utilities customers in the Horizon Utilities RZ that newly qualified as Class A customers effective July 1, 2017, under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA as Class B customers up to and including June 30, 2017; and paid GA as Class A customers from July 1, 2017 to December 31, 2017. As such, these customers should be allocated only the portion of the GA account balance which accrued prior to their classification as Class A customers (i.e. from January 1, 2017 to June 30, 2017).

There was one Horizon Utilities' customer who ceased to qualify as a Class A customer effective July 1, 2017 under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). This customer paid GA and CBR as Class A customer up to and including June 30, 2017; and paid GA and CBR as Class B customer from July 1, 2017 to December 31, 2017.

As such, these customers should be allocated only the portion of the GA account balance which accrued after their reclassification to Class B customers (i.e. from July 1, 2017 to December 31, 2017).

These GA and CBR amounts will be settled through twelve equal adjustments to bills as directed in the Chapter 3 Filing Requirements. These customers will not be charged the GA or CBR rate riders.

Table 39 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

The total GA balance to be disposed of is $2,405,185, of which $2,190,170 will be disposed of via rate rider; and $205,940 and $9,075 will be disposed of via specific bill adjustments to the 36 new Class A customers and 1 new Class B customers respectively, as discussed above. Tabs "6A. GA Allocation Class A" and, "6B. GA Allocation_new Class B" in the IRM Model identify the detailed calculation of the bill adjustments.

The total CBR balance to be disposed of is ($55,880), of which ($53,803) will be disposed of via rate rider; and ($1,990) and ($88) will be disposed of via specific bill adjustments to the 36 new Class A customers and 1 new Class B customers respectively, as discussed above. Tabs "7A.CBR Allocation Class A" and, "7B. CBR Allocation_new Class B" in the IRM Model identify the detailed calculation of the bill adjustments.

Alectra Utilities requests disposition of its GA balance of $215,015 and its CBR balance of ($2,077) related to its 36 new Class A customers and 1 new Class B customer (effective July 1, 2017) respectively, through the bill adjustments identified in the IRM Model.

Table 39 –Disposition of GA and CBR Balances – Horizon Utilities RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	$2,190,170
Global Adjustment - New Class A Customers July 1/2017	$205,940
Global Adjustment - New Class B Customers July 1/2017	$9,075
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**$2,405,185**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	($53,803)
Capacity Based Recovery - New Class A Customers July 1/2017	($1,990)
Capacity Based Recovery - New Class B Customers July 1/2017	($88)
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($55,880)**

A summary of the rate riders applicable to each group of customers is identified in Table 40 below.

Table 40 – Rate Riders by Customer Group – Horizon Utilities RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2017 - Dec 31, 2017)	x	x			
Class B non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class A (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class A non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class B (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class B non-RPP (Jan 1, 2017 - Dec 31, 2017) Customers	x	x	x	x	
Class B RPP Customers	x	x	x		

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges.

Class A customers (who were Class A from January 1 – December 31, 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Class B, non-RPP customers (who were Class A customers for only a part of 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class A, non-RPP customers (who were Class B customers for only part of 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers (who were Class B from January 1 – December 31, 2017) are charged the sum of DVA Rate Riders 1 and 2; the GA Rate Rider; and the CBR B Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR B Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 41, below. The amount to be disposed of by rate rider is ($7,084,034) and the amount to be disposed of via customer specific bill adjustments is ($212,938) ($215,015 GA and ($2,077 CBR)).

Table 41 – Group 1 DVAs Disposition by Customer Group – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	$601,110
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($28,637)
Retail Transmission Network Charge	1584	($192,674)
Retail Transmission Connection Charge	1586	$443,506
Disposition and Recovery/Refund of Regulatory Balances	1595	$0
All Customers - DVA Rate Rider 1		**$823,304**
Power	1588	($5,319,006)
Wholesale Market Service Charge excluding CBR	1580	($4,724,700)
All Customers ex WMPs - DVA Rate Rider 2		**($10,043,706)**
Wholesale Market Service Charge - CBR Class B	1580	($53,803)
Wholesale Market Service Charge - New Class A/B Customers July 1/2017		($2,077)
All Class B Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($55,880)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2017 -Dec 31/2017	1589	$2,190,170
Global Adjustment - New Class A/B Customers July 1/2017	1589	$215,015
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**$2,405,185**
Total (Repayment to)/Recovery from Customers		**($6,871,097)**
Disposition via Rate Rider		($7,084,034)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2017		$215,015
Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2017		($2,077)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2017 actuals reported in Alectra Utilities 2017 RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 8 in the IRM Model filed as Attachment 6. Table 42 below summarizes the deferral and variance rate riders by class.

Table 42 – Disposition of GA and CBR Balances – Horizon Utilities RZ

Customer Class	Deferral/Variance Account Rate Rider		Deferral/Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B Jan 1 - Dec 31, 2017		CBR B Rate Rider Class B Consumer Jan 1 - Dec 31, 2017	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0021)				0.0016		(0.00002)	
General Service Less Than 50 Kw	(0.0021)				0.0016		(0.00002)	
General Service 50 To 4,999 Kw		0.0599		(0.8319)	0.0016			(0.00542)
Large Use (1)		0.0798		(1.2566)	0.0016			0.02427
Large Use (2)		0.0875		(0.8911)	0.0000			0.01049
Unmetered Scattered Load	(0.0021)				0.0016		(0.00002)	
Sentinel Lighting		(0.9877)			0.0016			(0.00723)
Street Lighting		(0.7592)			0.0016			(0.00556)

Alectra Utilities requests disposition of the Horizon Utilities RZ adjusted Group 1 balances of ($7,084,034), identified in Table 41, through the rate riders identified in Table 42, above. Alectra Utilities also requests disposition of the CBR B rate rider to the fifth decimal place for the Horizon Utilities RZ. The OEB indicates in the Treatment of Negligible Rate Adders and Rate Riders on page 26 of the Chapter 3 Filing Requirements that:

> *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.*

However, Alectra Utilities proposes that the CBR B balance be cleared with a volumetric rate rider to five decimal places in 2019 for the Horizon Utilities RZ. 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. The OEB approved this approach in Alectra Utilities' 2018 EDR Application.

For a typical RPP Residential customer consuming 750 kWh per month, the total monthly bill impact of the proposed Group 1 rate riders is a decrease of ($2.04)/month or (1.89%) on total bill.

GA Analysis Workform

The GA Analysis Workform ("GA Workform") for the Horizon Utilities RZ is filed as Attachment 7. The GA Workform compares the principal activity in the general ledger for Account 1589, Global Adjustment to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in Account 1589 for a specific year is reasonable.

The principal activity in Account 1589 recorded in 2017 was ($1,322,742) as identified in Table 43 below. The principal activity balance, after known adjustments of $3,650,554 was $2,327,812. This is compared to the expected principal balance in Account 1589 of $1,198,423 calculated in Attachment 7, which results in an unreconciled difference of $1,129,389. This represents 0.73% of Alectra Utilities 2017 IESO purchases in the Horizon Utilities RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 43 – GA Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	($1,322,742)
Add Known Adjustments	$3,650,554
Adjusted Principal Activity in RSVA(GA)	$2,327,812
Expected Principal Activity in RSVA(GA)	$1,198,423
Variance $	$1,129,389
Total 2017 IESO Purchases	$155,193,480
Absolute Variance as a % of IESO Purchases	0.73%

SETTLEMENT PROCESS WITH THE IESO

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its settlements process with the IESO or host distributor. Distributors must specify the Global Adjustment rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. Horizon Utilities RZ provides the settlement process below.

The manner in which Alectra Utilities settles for the Horizon Utilities RZ with the IESO is provided in Table 44 below and depends on the following: (i) whether the customer is a Regulated Price Plan ("RPP") consumer; and (ii) whether the customer is a Class A or Class B consumer. It is not dependent on the rate class.

Table 44 – Settlement Process with the IESO – Horizon Utilities RZ

Customer	GA Rate used for Billing	GA Rate used to Record Cost	Settlement Process	Consumption Estimates	Impact on GA Variance Account
Class A	Actual	Actual	Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	Class A consumption actuals are submitted to the IESO - actuals are known at the time of submission; therefore an estimate is not required	none
Class B non-RPP	1st Estimate	Actual	Alectra Utilities pays the IESO Actual GA and bills customers 1st estimate GA - no further settlement with the IESO is required	Class B non-RPP consumption is not submitted to the IESO; however an estimate is used in order to calculate the RPP consumption used in the RPP vs. Market Price Claim[2]	Difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP consumers on disposal of the GA Variance Account
Class B RPP	RPP Time-of-Use ("TOU") or Tiered Rates[1]	Actual	Alectra Utilities pays the IESO Actual GA and bills customers RPP rates - Alectra Utilities settles with the IESO on an monthly basis via the RPP vs. Market Price Claim[2]	RPP consumption is estimated and provided to the IESO as part of the RPP vs. Market Price Claim[2] provided to the IESO	none

1. GA is not billed separately for Class B RPP customers; incorporated into RPP Rates
2. RPP vs. Market Price Claim is discussed in further detail below

<u>Class A Customers</u>: The IESO publishes the actual GA for a month on the tenth business day of the following month. Class A Customers are billed by Alectra Utilities around the 15th of each month, at which time the actual GA is known. Alectra Utilities pays the IESO Class A GA actual for the Horizon Utilities RZ based on its customers' percentage contribution to the top five peak Ontario demand hours. No further settlement with the IESO is required. Alectra Utilities settles GA costs with Class A customers for the Horizon Utilities RZ on the basis of actual costs. None of the variance in the GA account balance is attributed to these customers, as previously mentioned.

Alectra Utilities submits total Class A actual demand for the Horizon Utilities RZ to the IESO on a monthly basis. An estimate is not required since actual consumption is known at the time of submission.

<u>Class B non-RPP Customers</u>: Class B non-RPP customers are billed in the Horizon Utilities RZ throughout the month. These customers pay the spot price for energy – either the Weighted Average Hourly Spot price ("WAHSP") or the Hourly Ontario Energy Price ("HOEP"); and the GA. Horizon Utilities RZ bills its Class B non-RPP customers using the IESO's 1st estimate for GA for the month which is published by the IESO on the last business day of the preceding month. Horizon Utilities RZ pays the IESO Class B GA based on its actual Class B volume at the actual Class B rate. No further settlement with the IESO is required. Any difference between GA revenues and GA costs are recorded in the GA variance account to be recovered from or repaid to Class B non-RPP customers. Alectra Utilities allocates the Class B GA billed by the IESO to its RPP and non-RPP customers for the Horizon Utilities RZ based on consumption. Class B non-RPP consumption is equal to the consumption for all customers billed at spot pricing (interval metered and non-interval metered) less the consumption for Class A customers. Actual consumption for interval metered spot customers and Class A customers is obtained from MV90, a data and processing application owned by Itron used for interval meter data collection, management and analysis. Non-interval metered consumption is estimated using billed kWh from the Horizon Utilities RZ billing system. The proportion of Class B non-RPP consumption to total Class B consumption is used to determine the actual GA allocated to Class B non-RPP customers on a monthly basis. Total Class B consumption is defined as the following:

Total kWh wholesale power purchased from the IESO

Add: Embedded Generation

Less: Class A consumption

The determination of Class B RPP consumption is discussed in further detail below.

Class B RPP Customers: Class B RPP customers are billed by Horizon Utilities RZ throughout the month at RPP TOU or Tiered Rates. The difference between how much Horizon Utilities RZ recovers from RPP customers at these rates and the amount Horizon Utilities RZ pays for the commodity supply in the wholesale marketplace to the IESO, is recorded and managed in an account by the IESO.

On a monthly basis, Alectra Utilities determines the balance in this account for the Horizon Utilities RZ and submits it to the IESO ("the RPP vs. Market Price claim"). The amount submitted is reflected on the invoice as either a debit (Alectra Utilities-Horizon Utilities RZ collected more revenue from RPP customers than it paid for electricity) or a credit (Alectra Utilities -Horizon Utilities RZ collected less revenue from RPP customers than it paid for electricity). Alectra Utilities compares the amount collected from RPP customers (kWh billed at TOU or Tiered Pricing) to the amount it pays to the IESO for the Horizon Utilities RZ for electricity for that same volume, to determine this amount. There are three components to the RPP vs. Market Price claim:

1. Estimated Claim for the Current Month (based on Estimated Purchases and Energy Prices)
2. True-up of Prior Month Claim using Actual Purchases and Energy Prices
3. True-up of "Current Month (5-month lag)" Claim using Actual Billed Consumption

1. Estimated Claim for the Current Month (based on Estimated Purchases and Energy Prices)

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available until five months post consumption due to a billing lag, Alectra Utilities estimates the eligible kWh for the Horizon Utilities RZ using wholesale power purchased from the IESO for the current month and makes an adjustment to reflect billed kWh five months later.

Eligible kWh includes embedded generation and is defined as the following:

Total kWh wholesale power purchased from the IESO

Add: Embedded Generation

Less: kWh Consumption for Interval Metered Customers billed at Spot

Less: Billed kWh for Non-Interval Metered Customers billed at Spot (monthly consumption is not available from the billing system for these customers so billed kWh is used as a proxy for consumption.

2. True-up of Prior Month Claim using Actual Purchases and Energy Prices

In the month after the RPP vs. Market Price claim is submitted, more accurate information is available to determine the claim. The prior month's claim is recalculated using updated values for purchases and energy prices. The differences between the current month's claim and the re-estimated claim is submitted in the subsequent month (e.g., re-estimated claim for April is submitted as part of the May RPP vs. Market Price Claim). Although this results in a more accurate claim amount, eligible kWhs are still based on purchases not actual consumption. The RPP vs. Market Price claim is trued up five months later when consumption is available from the billing system.

3. True-up of "Current Month (5-month lag)" Claim using Actual Billed Consumption

The original estimate and revised estimate of eligible kWh and associated dollar amounts are based on a top-down estimate of RPP consumption using wholesale power purchased. The Horizon Utilities RZ billing system is used to determine the actual kWh consumed by and billed to RPP customers. This information is not available until five months after the claim has been submitted to the IESO (there is a time lag between consumption and billing which is dependent upon a customer's meter read cycle and billing frequency). The true-up of the original estimate based on power purchased occurs one month after the original claim is filed. The final true-up based on actual billed consumption occurs five months after the original claim is filed as identified in Table 45 below.

Table 45– Timing of RPP vs. Market Claim True-up – Horizon Utilities RZ

April Submission	Original Claim	Revised Claim True-Up	Actual Claim True-Up
Period	April	May	November

The billed kWh consumption and corresponding dollar values are available from Horizon Utilities RZ's billing. These are allocated by month based on the customer's meter read date range – it is assumed that consumption occurs evenly over the period (same kWh usage and dollar per day). Although kWh consumption by hour is available from smart meters it is not available in the billing system; or aggregated elsewhere.

The calculation is performed five months subsequent to the customer's consumption to ensure that 100% of consumption for a particular month is captured (for example, after five months, 100% of consumption for November 2014 will have been billed by April 2015). Similar to the true-up for the prior month's claim discussed previously, the actual claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to the true-up for that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

DISPOSITION OF LRAM VARIANCE ACCOUNT

Alectra Utilities is applying for disposition of the balance in the LRAM variance account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities in 2016 in the Horizon Utilities RZ. The total amount requested for disposition is a debit of $649,803 including forecasted carrying charges of $21,954 through to December 31, 2018. Actual savings from CDM activities for 2016 was above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in Alectra Utilities 2018 EDR Application (EB-2017-0024). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2013 through 2015 in the Horizon Utilities RZ.

Lost Revenue Adjustment Mechanism for 2011-2014 and 2015-2020

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive to the OEB (the "Directive") to establish electricity and conservation and demand management targets to be met by licensed electricity distributors over a four year period commencing January 1, 2011. The Minister of Energy and Infrastructure included guidance to the OEB that lost revenues that result from CDM programs should not act as a disincentive to a distributor to promote CDM activities.

On April 26, 2012, in response to the Directive, the OEB issued a new set of *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets that are a condition of licence. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period.

The OEB authorized the establishment of an LRAMVA to record, at the customer rate-class level, the difference between:

(i) the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for CDM programs, and

(ii) the level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

The variance calculated from the comparison will result in a credit or a debit to the ratepayer at the customer class level in the LRAMVA.

On March 31, 2014, the Ministry of Energy and Infrastructure, in response to the Government of Ontario's Long-Term Energy Plan ("LTEP"), issued a directive to the OEB ("the Conservation Directive") to promote CDM, including amending the licences of electricity distributors and establishing CDM Requirement guidelines (the "2015 CDM Guidelines").

On December 19, 2014, the OEB issued *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* (EB-2014-0278) ("2015 CDM Guidelines") which amended the electricity distribution licences of all electricity distributors to include a condition that requires the distributors to make CDM programs available to each customer segment in their service area and to report annual CDM results to the IESO. The Board also requires that electricity distributors work with natural gas distributors and the IESO in coordinating and integrating electricity conservation and natural gas demand side management programs. The 2015 CDM Guidelines also confirmed the continuation of the LRAM mechanism to compensate distributors for lost revenues resulting from CDM programs for the 2015 to 2020 period.

On May 19, 2016, the OEB issued an *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs,* on the calculation of the LRAMVA in respect of peak demand savings. In this report, the OEB determined that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year. The OEB also indicated that peak demand savings from Demand Response ("DR") programs should generally not be included within the LRAMVA calculation.

LRAM Calculations

The OEB has identified that distributors can apply for disposition of the balance in the LRAMVA as part of their cost of service applications and may apply for disposition on an annual basis, as part of their IRM application, if the balance is deemed significant by the applicant. Alectra Utilities is requesting approval for recovery of lost revenues of $649,803, including carrying charges, which is above the materiality threshold for the Horizon Utilities RZ. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $602,301.

Alectra Utilities has determined the LRAM amount for the Horizon Utilities RZ in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines and its 2016 Updated Policy for the calculation of LRAMVA, in respect of peak demand savings. Alectra Utilities has completed the 2018 LRAMVA work form for the Horizon Utilities RZ provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA work form is filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016, and is provided in Attachment 12. Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Horizon Utilities RZ in its lost revenue calculation in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities provides the following information for the Horizon Utilities RZ:

(i) Alectra Utilities has used the most recent input assumptions available at the time of the program evaluation when calculating the lost revenue amount; and

(ii) Alectra Utilities has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of the lost revenue calculation. The IESO's Final Annual Verified Results for 2016 is filed as Attachment 13.

(iii) The IESO reports results by program. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Alectra Utilities estimated the split by rate class, drawing on participant-specific information where available; and

(iv) Alectra Utilities has provided additional data in Tab 10. Street Lighting of the LRAMVA Model in support of the Street Lighting project savings. Demand savings for the retrofit streetlight project do not appear on the IESO's Final Verified Result Report, as the reduction to peak demand occurs outside the IESO's peak hours. Demand savings were calculated based on the difference between billed kW demand based on streetlight reports from the municipalities and billed kW based on the demand prior to the LED streetlight project.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2017. Alectra Utilities proposes to dispose of its 2017 LRAMVA balance for the Horizon Utilities RZ in a future rate proceeding. Alectra Utilities identifies that the balance in Account 1568, LRAMVA, as identified in Tab "3. Continuity Schedule" does not match the amount being requested for disposition due to the exclusion of the 2017 balances as mentioned previously.

Alectra Utilities is seeking recovery of lost revenues for the Horizon Utilities RZ for the period January 1, 2016 to December 31, 2016 resulting from the following:

(i) 2015 CDM persistence savings in 2016; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2016.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 46 identified below.

Table 46 – Distribution Volumetric Rates – Horizon Utilities RZ

Year	Residential	GS<50 kW	General Service 50 to 4,999 kW	Large Use (1)	Large Use (2)	Street Lighting
	kWh	kWh	kW	kW	kW	kW
2016	$0.0121	$0.0106	$2.5413	$1.3985	$0.2609	$6.0733

Horizon Utilities' LRAMVA threshold approved in its 2015 Custom IR Application (EB-2014-0002) is used as the comparator against actual savings for the lost revenue calculation for 2016. Horizon Utilities' LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 47 identified below.

Table 47 – LRAMVA Thresholds – Horizon Utilities RZ

Year	LRAMVA Threshold	Residential	GS<50 KW	General Service 50 To 4,999 KW
		kWh	kWh	kW
2015	2015	3,350,520	928,649	34,728
2016	2015	6,454,043	1,775,136	69,456

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2016 to December 31, 2018 for the Horizon Utilities RZ in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $649,803, representing a principal balance of $627,849 and carrying charges of $21,954.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 48 and 49 below for the Horizon Utilities RZ, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 48 – LRAMVA Totals by Rate Class – Horizon Utilities RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$303,534	$10,614	$314,148
GS<50 kW	kWh	$268,013	$9,372	$277,385
General Service 50 To 4,999 KW	kW	($63,546)	($2,222)	($65,768)
Large Use (1)	kW	$7,731	$270	$8,002
Large Use (2)	kW	$11,361	$397	$11,758
Street Lighting	kW	$100,755	$3,523	$104,279
Total		**$627,849**	**$21,954**	**$649,803**

1 **Table 49 – LRAMVA by Year and Rate Class – Horizon Utilities RZ**

Description	Residential	GS<50 kW	General Service 50 To 4,999 KW	Large Use (1)	Large Use (2)	Street Lighting	Total
	kWh	kWh	kW	kW	kW	kW	
2016 Actuals	$381,628	$286,830	$112,962	$7,731	$11,361	$100,755	$901,268
2016 Forecast	($78,094)	($18,816)	($176,509)	$0	$0	$0	($273,419)
2016 LRAM Balance	**$303,534**	**$268,013**	**($63,546)**	**$7,731**	**$11,361**	**$100,755**	**$627,849**
Carrying Charges	**$10,614**	**$9,372**	**($2,222)**	**$270**	**$397**	**$3,523**	**$21,954**
Total LRAMVA Balance	**$314,148**	**$277,385**	**($65,768)**	**$8,002**	**$11,758**	**$104,279**	**$649,803**

2

3 The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are
4 identified in Table 50 below and included in Tab "8. Calculation of Def-Var RR" in the IRM
5 Model.

6 **Table 50 – LRAMVA Rate Riders – Horizon Utilities RZ**

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.00	$0.0002	kWh
General Service Less Than 50 kW	$0.00	$0.0005	kWh
General Service 50 To 4,999 kW	$0.00	($0.0136)	kW
Large Use (1)	$0.00	$0.0175	kW
Large Use (2)	$0.00	$0.0059	kW
Unmetered Scattered Load	$0.00	$0.0000	kWh
Sentinel Lighting	$0.00	$0.0000	kW
Street Lighting	$0.00	$1.1939	kW

SUMMARY OF BILL IMPACTS

A summary of bill impacts for the typical customer by rate class is presented in Tables 51 to 53 below. Attachment 3 provides a detailed summary of the bill impacts for each customer class for 2019.

Table 51 – Distribution Bill Impacts by Rate Class – Horizon Utilities RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.04)	(0.15)%
GS<50 kW	kWh	2,000	$ 2.39	3.81%
GS>50 kW	kW	250	$ 12.75	1.24%
Large User	kW	5,000	$ 636.36	2.01%
Large User with Dedicated Assets	kW	20,000	$ 330.83	2.70%
Street Lighting	kW	4,974	$ 3,240.86	3.18%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

Table 52 – Distribution Bill and Rate Rider Impacts by Rate Class – Horizon Utilities RZ

Distribution Bill and All Rate Rider Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (1.63)	(5.57)%
GS<50 kW	kWh	2,000	$ (1.85)	(2.70)%
GS>50 kW	kW	250	$ (5.61)	(0.85)%
Large User	kW	5,000	$ (5,126.29)	(16.90)%
Large User with Dedicated Assets	kW	20,000	$ (15,531.39)	(182.44)%
Street Lighting	kW	4,974	$ 2,288.49	2.39%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

1 **Table 53 – Total Bill Impacts by Rate Class (before HST) – Horizon Utilities RZ**

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (1.95)	(1.85)%
GS<50 kW	kWh	2,000	$ (16.60)	(5.90)%
GS>50 kW	kW	250	$ (811.43)	(5.41)%
Large User	kW	5,000	$ (23,832.22)	(6.73)%
Large User with Dedicated Assets	kW	20,000	$ (90,355.13)	(6.94)%
Street Lighting	kW	4,974	$ (10,745.94)	(3.28)%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

CONCLUSION

Alectra Utilities' proposed 2019 rates for the distribution of electricity in the Horizon Utilities RZ include the annual adjustments agreed upon in the Board-Approved Settlement Agreement in Horizon Utilities Custom IR Application and in the Board-Approved Decision and Order in Horizon Utilities 2016, 2017 and 2018 Annual Filings.

Alectra Utilities' Specific Service Charges for the Horizon Utilities RZ are consistent with those previously approved by the Board in Horizon Utilities' 2015 Tariff of Rates and Charges (EB-2014-0002).

Alectra Utilities respectfully requests that the Board approve the relief sought for the Horizon Utilities RZ in this Annual Filing.

BRAMPTON RATE ZONE

MANAGER'S SUMMARY

Alectra Utilities is applying for distribution rates and other charges in the Brampton RZ, pursuant to a Price Cap IR, effective January 1, 2019. This application impacts customers in the City of Brampton.

Alectra Utilities has completed the IRM Model for the Brampton RZ and will update the Application to include the 2019 IRM Rate Generator Model ("2019 IRM Model") when published by the OEB. This Application has been prepared in accordance with the updated *Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications* (the "Chapter 3 Filing Requirements"), dated July 20, 2017, including the key OEB reference documents listed therein, *the Letter from the Board to Licensed Electricity Distributors re: I. Updated Filing Requirements; and, II. Process for 2018 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications,* dated July 20, 2017.

Relief Sought in This Application

Alectra Utilities is seeking Board approval for the following in the Brampton RZ:

a. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's IRM Price Cap Index Adjustment Mechanism formula;

b. The continuation of the implementation of the new distribution rate design for residential electricity customers;

c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A customer;

e. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A customer;

f. The recovery of the net financial impact of the new capitalization policy in 2017 through rate riders over a one year period effective January 1, 2019;

g. An adjustment to the retail transmission service rates effective January 1, 2019;

h. 2019 Renewable Generation Connection Rate Protection from provincial ratepayers;

i. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period; and

j. Current (i.e., 2018) rates provided in Attachment 14 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

ANNUAL PRICE CAP ADJUSTMENT MECHANISM

As part of the *RRFE*, the OEB initiated a review of utility performance, per the *Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379)" proceeding. As part of this proceeding, the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board (the "PEG Report") entitled, *Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board*. The original PEG Report was issued on May 3, 2013. It established the parameters for use to determine the Price Cap Index for the 4th Generation IRM (now referred to as Price Cap IR), including: a productivity factor of 0.00%, the approach to determine the Industry Specific Inflation Factor (replacing the 3rd Generation IRM GDP-IPI inflation factor), and the initial stretch factor assignments.

Stretch Factor

The Stretch Factor assignments for 2019 IRM filers have not yet been updated by the Board. Alectra Utilities has used a Stretch Factor of 0.3% for the Brampton RZ in this Application, in accordance with the most recent PEG Report, issued on August 17, 2017. The August 2017 Report placed Alectra Utilities' Brampton RZ in Group III for the purpose of calculating stretch factors for 2018.

Inflation Factor

The Industry Specific Inflation Factor for 2019 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor for the Brampton RZ published for 2018 IRM filers, i.e., 1.2%, as a proxy for 2019.

Alectra Utilities will update the IRM Model with the 2019 stretch factor and inflation factor for the Brampton RZ, in order to calculate the Price Cap Index once these factors are published by the Board.

The Price Cap Index, as determined in the IRM Model, filed as Attachment 17 is 0.9%, is identified in Table 54, below.

Table 54 – Calculation of Price Cap Index – Brampton RZ

Factor	%
Inflation Factor	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.30%
Price Cap Index	**0.90%**

The Price Cap Index of 0.9% has been applied to Alectra Utilities' 2018 Service Charges and Distribution Volumetric Rates by rate class for the Brampton RZ to determine the 2019 Service Charges and Distribution Volumetric Rates. The Alectra Utilities 2019 Proposed Tariff of Rates and Charges for the Brampton RZ is filed as Attachment 15.

RATE DESIGN FOR RESIDENTIAL ELECTRICITY CUSTOMERS

On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Customers*, which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year period commencing in 2016 and ending in 2019.

The Board directed that "*Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral."*

Hydro One Brampton incorporated the first year transition adjustment in its proposed rates for 2016 in a manner consistent with OEB policy. As per the Decision and Order for the 2016 IRM Application[8]: "[The OEB] *find[s] that the increases to the monthly fixed charge and to low consumption consumers are consistent with OEB policy and approve the increase as calculated in the final rate model."*

Hydro One Brampton incorporated the second year transition adjustment in its proposed rates for 2017 in a manner consistent with OEB policy. As per the Decision and Order for the 2017 IRM Application[9], the Board confirmed that: *"the increases to the monthly fixed charge and to low consumption residential consumers are below the thresholds set in the OEB policy and [the OEB] approves the increase as proposed by the applicant and calculated in the final rate model*."

Alectra Utilities incorporated the third year transition adjustment in its proposed rates for 2018, for the Brampton RZ, in a manner consistent with OEB policy. As per the Decision and Order for the 2018 EDR Application[10], the Board confirmed that "*the proposed 2018 increase to the monthly fixed charge is in accordance with the OEB's 2015-0065 Decision and residential rate design policy. The results of the monthly fixed charge, and total bill impact for low volume*

[8] EB-2015-0078, p 8.

[9] EB-2016-0080, p.14.

[10] EB-2017-0024, p.76.

customer tests show no mitigation is required. The OEB approves the increase as proposed by the applicant and calculated in the final rate model."

Alectra Utilities has incorporated the final year transition adjustment in its proposed rates for the Brampton RZ for 2019. The calculation of the proposed residential fixed and variable rates is identified in Tab 17 "Rev2Cost-GDPIPI" of the IRM Model filed as Attachment 17.

The Board instructed distributors that, for the purposes of implementing the new fixed rate design, a 10% test will be applied to customers who consume much less electricity than the typical residential customers.
This will allow any mitigation plans to be tailored to those customers who use the least power and whose bills will likely increase due to the shift in the fixed rates. If a customer at the 10th consumption percentile level of electricity has a bill impact of 10% or higher, the distributor must make a proposal for a rate mitigation plan.

Alectra Utilities confirms that the Residential monthly service charge increase of $3.31 is below the threshold of $4 per month identified in the Board's policy. Accordingly, rate mitigation is not necessary since a customer at the lowest decile of electricity consumption will not have a bill impact of 10% or higher.

Alectra Utilities has followed the Board's direction to assess the combined effect of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service by evaluating the total bill impact for a residential customer at Brampton RZ's 10th consumption percentile. The following is a description of the method Alectra Utilities used to derive the 10th consumption percentile for the Brampton RZ:

1. Alectra Utilities ran a system query to obtain data for all Residential Class consumers of record as of December 31, 2017 for the Brampton RZ.

2. Through the query, Alectra Utilities obtained Brampton RZ data for 2017 for the metered consumption by month, the number of service months and the computed average monthly kWh consumption for all active Residential Class consumers, as of the end of 2017. Customers who had moved out were excluded and customers who moved in were included in the data.

3. The total number of active residential class customers with the average consumption over 50 kWh per month as of December 31, 2017 is 149,954. To identify the 10th percentile of lowest consumers above 50 kWh, the data for all Residential Class customers was sorted by average monthly consumption for 2017 from lowest to highest and 10% of the total number of customers above 50 kWh was determined to be the 14,995th lowest usage customer as follows: 10% of 149,954 Residential Customers = 14,995.

Alectra Utilities has provided the bill impact for a Residential customer that consumes 331 kWh, monthly in Table 55, below. The monthly service charge increased by $3.31 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 2.71%.

Table 55 – 10th Consumption Percentile Residential Customer Bill Impact (331 kWh) – Brampton RZ

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**331**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0341**	
Proposed/Approved Loss Factor	**1.0341**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	**$ 20.92**	1	$ 20.92	**$ 24.23**	1	$ 24.23	$ 3.31	15.82%
Distribution Volumetric Rate	**$ 0.0040**	331	$ 1.32	**$ -**	331	$ -	$ (1.32)	-100.00%
Fixed Rate Riders	**$ 0.50**	1	$ 0.50	**$ 0.61**	1	$ 0.61	$ 0.11	22.00%
Volumetric Rate Riders	**$ -**	331	$ -	**$ 0.0002**	331	$ 0.07	$ 0.07	
Sub-Total A (excluding pass through)			$ 22.74			$ 24.91	**$ 2.16**	**9.51%**
Line Losses on Cost of Power	**$ 0.0822**	11	$ 0.93	**$ 0.0820**	11	$ 0.93	$ (0.00)	-0.21%
Total Deferral/Variance Account Rate Riders	**-$ 0.0010**	331	$ (0.33)	**-$ 0.00224**	331	$ (0.74)	$ (0.41)	124.00%
GA Rate Riders								
Low Voltage Service Charge	**$ -**	331	$ -	**$ -**	331	$ -	$ -	
Smart Meter Entity Charge (if applicable)	**$ 0.57**	1	$ 0.57	**$ 0.57**	1	$ 0.57	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 23.91**			**$ 25.66**	**$ 1.75**	**7.32%**
RTSR - Network	**$ 0.0074**	342	$ 2.53	**$ 0.0072**	342	$ 2.46	$ (0.07)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0065**	342	$ 2.22	**$ 0.0063**	342	$ 2.16	$ (0.07)	-3.08%
Sub-Total C - Delivery (including Sub-Total B)			**$ 28.67**			**$ 30.28**	**$ 1.61**	**5.63%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	342	$ 1.23	**$ 0.0036**	342	$ 1.23	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	342	$ 0.10	**$ 0.0003**	342	$ 0.10	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	**$ 0.0650**	215	$ 13.98	**$ 0.0650**	215	$ 13.98	$ -	0.00%
TOU - Mid Peak	**$ 0.0950**	56	$ 5.35	**$ 0.0940**	56	$ 5.29	$ (0.06)	-1.05%
TOU - On Peak	**$ 0.1320**	60	$ 7.86	**$ 0.1320**	60	$ 7.86	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 57.45**			**$ 59.00**	**$ 1.56**	**2.71%**
HST	13%		$ 7.47	13%		$ 7.67	$ 0.20	2.71%
8% Provincial Rebate	-8%		$ (4.60)	-8%		$ (4.72)	$ (0.13)	2.71%
Total Bill on TOU			**$ 60.32**			**$ 61.95**	**$ 1.63**	**2.71%**

ELECTRICITY DISTRIBUTION RETAIL TRANSMISSION SERVICE RATES

The Board's *Guideline for Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") (G-2008-0001) was issued June 28, 2012. On January 25 2018, the OEB issued its Decision and Order in respect of the 2018 Uniform Transmission Rates ("UTRs") (EB-2017-0359). On December 21, 2016, the OEB issued its Decision and Order in respect of Hydro One Networks Inc. ("HONI") application for electricity distribution rates and other charges beginning January 1, 2017, which contain HONI's sub transmission rates ("STRs) at page 10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 56 below.

Table 56 – Current Board-Approved UTRs and STRs – Brampton RZ

UTRs	$
Network Service Rate	$3.61
Line Connection Service Rate	$0.95
Transformation Connection Service Rate	$2.34

STRs	$
Network Service Rate	$3.1942
Line Connection Service Rate	$0.7710
Transformation Connection Service Rate	$1.7493

Alectra Utilities has updated Tabs 11-15 of the IRM Model for the Brampton RZ, filed as Attachment 17, to incorporate: i) the most recent UTRs and STRs approved by the Board; and ii) an update to Alectra Utilities demand in the Brampton RZ from 2016 to 2017 actual values. The RTSRs are calculated in Tab 16 of the IRM Model.

Alectra Utilities will update the RTSRs for the Brampton RZ, should the actual UTRs and STRs be approved prior to the OEB issuing the final rate order for this application.

The RTSR rates for the Embedded Distributor service class are equal to RTSR rates for General Service 700 to 4,999 kW service class, as approved by the OEB at Hydro One Brampton's request in its 2015 Cost of Service application (EB-2014-0083) in Exhibit 7, Tab 1, Schedule 3.

REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative (*EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met. Consistent with a Letter from the Board to Licensed Electricity Distributors re: *Process for 2015 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*, dated July 25, 2014, distributors may also elect to dispose of Group 1 account balances below the threshold.

Group 1 accounts consist of the following Uniform System of Accounts ("USoA"):

- 1550 - Low Voltage Account;
- 1551 - SME Charge Account;
- 1580 - RSVA Wholesale Market Service Charge Account;
- 1584 - RSVA Retail Transmission Network Charge Account;
- 1586 - RSVA Retail Transmission Connection Charge Account;
- 1588 - RSVA Power Account;
- 1589 - RSVA Global Adjustment Account;
- 1590 - Recovery of Regulatory Asset Balances Account (if applicable); and
- 1595 - Disposition and Recovery/Refund of Regulatory Balances Account.

The Group 1 balances for the Brampton RZ as of December 31, 2017, in the amount of ($10,718,798) have been adjusted for the following items to determine the amount for disposition of ($2,875,293), as identified in Table 57, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition as directed in the OEB's letter on the *"Guidance on the*

Disposition of Accounts 1588 and 1589", dated May 23, 2017. For the Brampton RZ, an adjustment of ($623,541) and $2,212,711 has been made to Account 1588 and Account 1589 respectively, to reflect RPP settlement true-up claims for 2017 that were settled in 2018. These amounts have been entered into the IRM model, Tab "3. Continuity Schedule" Column "Principal Adjustment during 2017". See Table 57 below for a summary of this adjustment. Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;

- Only Class B Capacity Based Recovery ("CBR") amounts are to be disposed of through this rate proceeding as directed by the OEB in its *Accounting Guidance on Capacity Based Recovery* issued July 25, 2016 and;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e. the amount for disposition includes 2018 projected carrying charges).

Table 57 – Group 1 Account Balances for Disposition – Brampton RZ

Description	Amount
Group 1 Account Balances as of December 31, 2017	**($10,718,798)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers	($5,666,082)
RPP Settlement True-up Claims Adjustment	$1,589,170
Add Projected Carrying Charges	($57,434)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	$645,687
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($2,875,293)**

Alectra Utilities has computed the disposition threshold for the Brampton RZ, based on the adjusted Group 1 balances, to be ($0.0007)/kWh, as identified in Table 58, below. Alectra Utilities requests disposition of its Group 1 account balances for the Brampton RZ in this Application.

Table 58 – Calculation of Disposition Threshold – Brampton RZ

Description	Account	Amount
Low Voltage	1550	$452,865
Smart Meter Entity Charge	1551	($127,046)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	($124,827)
RSVA - Wholesale Market Service Charge excluding CBR	1580	($7,733,770)
RSVA - Retail Transmission Network Charge	1584	($468,250)
RSVA - Retail Transmission Connection Charge	1586	$491,094
RSVA - Power	1588	($234,842)
RSVA - Global Adjustment	1589	($2,069,408)
Disposition and Recovery/Refund of Regulatory Balances	1595	($904,614)
Group 1 Account Balances as of December 31, 2017		**($10,718,798)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers		($5,666,082)
RPP Settlement True-up Claims Adjustment		$1,589,170
Add Projected Carrying Charges		($57,434)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		$645,687
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($2,875,293)**
2017 kWhs		3,937,310,163
Threshold Test $/kWh		**($0.0007)**

Alectra Utilities has completed Tab 3. Continuity Schedule of the IRM Model for the Brampton RZ, filed as Attachment 17. Alectra Utilities has reconciled the Group 1 balances filed in the 2017 RRR for the Brampton RZ, section 2.1.7 as identified in Table 59 below. Alectra Utilities confirms that the last Board approved balance of ($5,666,082) for Brampton RZ has been transferred to Account 1595 (as identified in Alectra Utilities' 2018 EDR Application EB-2017-0024). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2017 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances for the Brampton RZ. The prescribed interest rate of 1.5% for 2018 Q1 and 1.89% for 2018 Q2-Q4 were used to calculate forecasted interest for 2018. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 59 – Deferral and Variance Account Reconciliation – Brampton RZ

Account Description	Account	Principal Amounts as of Dec 31, 2017	Carrying Charges to Dec 31, 2017	Principal Disposition during 2018 - instructed by Board EB-2017-0024	Interest Disposition during 2018 - instructed by Board EB-2017-0024	Projected Carrying Charges to Dec 31, 2018	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims 2017 Reversal	Projected Carrying Charges to December 31, 2018	1595 Balances Not Claimed in 2019	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	447,496	5,369	(247,217)	(5,527)	3,590	203,711				203,711
Smart Meter Entity Charge	1551	(125,838)	(1,208)	59,949	1,277	(1,181)	(67,001)				(67,001)
RSVA - Wholesale Market Service Charge - CBR B	1580	(121,943)	(2,885)	-	-	(2,186)	(127,013)				(127,013)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(7,652,872)	(80,898)	3,726,242	81,704	(70,385)	(3,996,208)				(3,996,208)
RSVA - Retail Transmission Network Charge	1584	(459,597)	(8,653)	479,528	11,826	357	23,461				23,461
RSVA - Retail Transmission Connection Charge	1586	483,895	7,199	(555,267)	(11,840)	(1,279)	(77,293)				(77,293)
RSVA - Power	1588	(220,873)	(13,969)	217,342	14,511	(63)	(3,053)	(623,541)	(11,177)		(637,771)
Sub-total not including RSVA Power Global Adjustment		(7,649,731)	(95,045)	3,680,577	91,950	(71,147)	(4,043,396)	(623,541)	(11,177)		(4,678,115)
RSVA - Power Global Adjustment	1589	(2,079,678)	10,270	1,611,142	17,112	(8,399)	(449,553)	2,212,711	39,663		1,802,822
Total including RSVA Power Global Adjustment		(9,729,410)	(84,775)	5,291,719	109,063	(79,546)	(4,492,949)	1,589,170	28,486		(2,875,293)
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	(924)	(15)	924	21	-	6			6	-
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	264,414	(98,894)	(263,919)	101,951	9	3,561			3,561	-
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	(424,905)	(683)	424,904	1,421	(0)	737			737	-
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	(356,113)	(287,495)	-	-	(6,383)	(649,991)			(649,991)	-
Total 1595		(517,527)	(387,087)	161,909	103,392	(6,374)	(645,687)	-	-	(645,687)	-
Total Group 1		**(10,246,936)**	**(471,862)**	**5,453,628**	**212,455**	**(85,920)**	**(5,138,636)**	**1,589,170**	**28,486**	**(645,687)**	**(2,875,293)**
Total Amount for Disposition		**(10,246,936)**	**(471,862)**	**5,453,628**	**212,455**	**(85,920)**	**(5,138,636)**	**1,589,170**	**28,486**	**(645,687)**	**(2,875,293)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances in the Brampton RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year*".

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders for the Brampton RZ to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Recovery (‘CBR”) Disposition

Alectra Utilities has also established separate rate riders to dispose of the global adjustment (“GA”) and the Capacity Based Response (“CBR”) account balances for the Brampton RZ. The GA rate riders are applicable for non-RPP Class B customers only and the CBR rate riders are applicable for Class B customers only. Alectra Utilities’ Brampton RZ’s Class A customers are invoiced actual GA and CBR and as such none of the variance in the GA and CBR account balances should be attributed to these customers.

There were 72 Brampton RZ customers, that newly qualified as Class A customers effective July 1, 2017 under the IESO’s expansion of the Industrial Conservation Initiative (“ICI”). These customers paid GA and CBR as Class B customers up to and including June 30, 2017; and paid GA and CBR as Class A customers from July 1, 2017 to December 31, 2017 These customers should be allocated only the portion of the GA and CBR account balances which accrued prior to their classification as Class A customers (i.e. from January 1, 2017 to June 30, 2017).

There were no Alectra Utilities customers, in the Brampton RZ, that ceased to qualify as a Class A customer effective July 1, 2017, under the IESO’s expansion of the Industrial Conservation Initiative (“ICI”).

These GA and CBR amounts will be settled through twelve equal adjustments to bills, as directed in the Chapter 3 Filing Requirements. These customers will not be charged the GA or CBR rate riders.

Table 60 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

The total GA balance to be disposed of is $1,802,822, of which $1,501,122 will be disposed of via rate riders and $301,700 will be disposed of via specific bill adjustments for the 72 new Class A customers, as discussed above. Tabs “6A. GA Allocation Class A” in the IRM Model identify the detailed calculation of the total bill adjustments of $301,700.

The total CBR balance to be disposed of is ($127,013) of which ($117,083) will be disposed of via rate riders and ($9,930) will be disposed of via specific bill adjustments to the 72 new Class A customers, as discussed above. Tabs “7A. CBR Allocation_Class A” in the IRM Model identify the detailed calculation of the total bill adjustments of ($9,930).

Alectra Utilities requests disposition of its GA balance of $301,700 and its CBR balance of ($9,930) related to its 72 new Class A customers for the Brampton RZ (effective July 1, 2017) respectively, through the bill adjustments identified in the IRM Model.

Table 60 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Table 60 – Disposition of GA and CBR Balances – Brampton RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	$1,501,122
Global Adjustment - New Class A Customers July 1/2017	$301,700
Global Adjustment - New Class B Customers July 1/2017	-
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**$1,802,822**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	($117,083)
Capacity Based Recovery - New Class A Customers July 1/2017	($9,930)
Capacity Based Recovery - New Class B Customers July 1/2017	-
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($127,013)**

A summary of the rate riders applicable to each group of customers is identified in Table 61 below.

Table 61 – Rate Riders by Customer Group – Brampton RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2017 - Dec 31, 2017)	x	x			
Class B non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class A (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class A non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class B (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class B non-RPP (Jan 1, 2017 - Dec 31, 2017) Customers	x	x	x	x	
Class B RPP Customers	x	x	x		

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges

Class A customers (that were Class A from January 1 – December 31, 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Class A, non-RPP customers (who were Class B customers for only part of 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers (who were Class B from January 1 – December 31, 2017) are charged the sum of DVA Rate Riders 1 and 2; the GA Rate Rider; and the CBR B Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR B Rate Rider.

The Group 1 Disposition by customer group is identified in Table 62 below. The amount to be disposed of by rate rider is ($3,167,063) and the amount to be disposed of via customer specific bill adjustments is $301,700 GA and ($9,930) CBR.

Table 62 – Group 1 Disposition by Customer Group – Brampton RZ

Description	Account	Amount
Low Voltage	1550	$203,711
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($67,001)
Retail Transmission Network Charge	1584	$23,461
Retail Transmission Connection Charge	1586	($77,293)
Disposition and Recovery/Refund of Regulatory Balances	1595	$0
All Customers - DVA Rate Rider 1		**$82,878**
Power	1588	($637,771)
Wholesale Market Service Charge excluding CBR	1580	($3,996,208)
All Customers ex WMPs - DVA Rate Rider 2		**($4,633,979)**
Wholesale Market Service Charge - CBR Class B	1580	($117,083)
Wholesale Market Service Charge - New Class A/B Customers July 1/2017		($9,930)
All Class B Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($127,013)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2017 -Dec 31/2017	1589	$1,501,122
Global Adjustment - New Class A/B Customers July 1/2017	1589	$301,700
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**$1,802,822**
Total (Repayment to)/Recovery from Customers		**($2,875,293)**
Disposition via Rate Rider		($3,167,063)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2017		$301,700
Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2017		($9,930)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2017 actuals, reported in Alectra Utilities' 2017 RRRs, have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 7 in the IRM Model filed as Attachment 17. Table 63 below summarizes the deferral and variance account rate riders by customer class. As identified in the Chapter 3 Filing Requirements, "*Effective in 2017, the billing determinant and all the rate riders for the GA will be calculated on an energy basis (kWhs) regardless of the billing determinant used for distribution rates for the particular class*."

Table 63 – Proposed Rate Riders by Customer Class – Brampton RZ

Customer Class	Deferral/Variance Account Rate Rider		Deferral/Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B Jan 1 - Dec 31, 2017		CBR B Rate Rider Class B Consumer Jan 1 - Dec 31, 2017	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential Service Classification	(0.0012)				0.0012		(0.00004)	
General Service Less Than 50 Kw Service Classification	(0.0012)				0.0012		(0.00004)	
General Service 50 To 699 Kw Service Classification		0.0134		(0.4220)	0.0012			(0.01435)
General Service 700 To 4,999 Kw Service Classification		0.0162		(0.4994)	0.0012			(0.01440)
Large Use Service Classification		(0.6290)						0.00000
Unmetered Scattered Load Service Classification	(0.0012)				0.0012		(0.00004)	
Street Lighting Service Classification		(0.4067)			0.0012			(0.01422)
Embedded Distributor Service Classification		(0.0012)			0.0012			(0.00004)
Distributed Generation [Dgen] Service Classification		(0.0012)			0.0012			(0.00004)

Alectra Utilities requests disposition of its adjusted Group 1 balances of ($3,167,063) for the Brampton RZ, identified in Table 62, through the rate riders identified in Table 63, above. Alectra Utilities also requests disposition of the CBR B rate rider to the fifth decimal place for the Brampton RZ. The OEB indicates in the Treatment of Negligible Rate Adders and Rate Riders on page 26 of the Chapter 3 Filing Requirements that:

> *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.*

However, Alectra Utilities proposes that the CBR B balance be cleared with a volumetric rate rider to five decimal places in 2018 for the Brampton RZ. 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. The OEB approved this approach in Alectra Utilities' 2018 EDR Application.

Alectra Utilities identified in its 2018 EDR Application that the Brampton RZ's CIS system was unable to accommodate rate riders to the fifth decimal place. As Alectra Utilities will transition the Brampton RZ's customers to Alectra Utilities' billing system in 2018, Alectra Utilities will be able to accomodate the billing of the rate riders to the fifth decimal place.

For a typical RPP Residential customer consuming 750 kWh per month, the total monthly bill impact of the proposed Group 1 rate riders is a decrease of ($1.68)/month or (1.36%) on the total bill.

GA Analysis Workform

The GA Analysis Workform (“GA Workform”) for the Brampton RZ is filed as Attachment 18. The GA Workform compares the principal activity in the general ledger for Account 1589, to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in Account 1589 in a specific year is reasonable.

The principal activity in Account 1589 recorded in 2017 was ($468,536) as identified in Table 64 below. The principal activity balance, after known adjustments of $2,212,711 was $1,744,175 This is compared to the expected principal balance in Account 1589 of $606,629 calculated in Attachment 18, which results in an unreconciled difference of $1,137,547. This represents 0.70% of Alectra Utilities 2017 IESO purchases in the Brampton RZ, which is within the OEB’s threshold (+/- 1% of IESO purchases).

Table 64 – GA Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	($468,536)
Add Known Adjustments	$2,212,711
Adjusted Principal Activity in RSVA(GA)	$1,744,175
Expected Principal Activity in RSVA(GA)	$606,629
Variance $	$1,137,547
Total 2017 IESO Purchases	$162,942,632
Absolute Variance as a % of IESO Purchases	0.70%

SETTLEMENT PROCESS WITH THE IESO

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its settlements process with the IESO or host distributor. Distributors must specify the Global Adjustment rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. Alectra Utilities provides its settlement process for the Brampton RZ with the IESO, below.

The manner in which Alectra Utilities settles with the IESO for the Brampton RZ is provided in Table 65 below and depends on the following: (i) whether the customer is a Regulated Price Plan ("RPP") consumer; and (ii) whether the customer is a Class A or Class B consumer. It is not dependent on the rate class.

Table 65 – Settlement Process with the IESO - Brampton RZ

Customer	GA Rate used for Billing	GA Rate used to Record Cost	Settlement Process	Consumption Estimates	Impact on GA Variance Account
Class A	Actual	Actual	Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	Class A consumption actuals are submitted to the IESO - actuals are known at the time of submission; therefore an estimate is not required	none
Class B non-RPP	1st Estimate	Actual	Alectra Utilities pays the IESO Actual GA and bills customers 1st estimate GA - no further settlement with the IESO is required	Class B non-RPP consumption is not submitted to the IESO; however an estimate is used in order to calculate the RPP consumption used in the RPP vs. Market Price Claim[2]	Difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP consumers on disposal of the GA Variance Account
Class B RPP	RPP Time-of-Use ("TOU") or Tiered Rates[1]	Actual	Alectra Utilities pays the IESO Actual GA and bills customers RPP rates - Alectra Utilities settles with the IESO on an monthly basis via the RPP vs. Market Price Claim[2]	RPP consumption is estimated and provided to the IESO as part of the RPP vs. Market Price Claim[2] provided to the IESO	none

1. GA is not billed separately for Class B RPP customers; incorporated into RPP Rates
2. RPP vs. Market Price Claim is discussed in further detail below

<u>Class A Customers</u>: The IESO publishes the actual GA for a month on the tenth business day of the following month. The GA costs invoiced to Alectra Utilities for the Brampton RZ by the IESO represents the total provincial system-wide GA costs for the month multiplied by the Brampton RZ peak demand factor, which is the aggregate of its Class A customers' peak demand factors. No further settlement with the IESO is required. Alectra Utilities bills Class A customers in the Brampton RZ the GA based on their respective peak demand factors or their percentage contribution to the top five peak Ontario demand hours. There is no variance in the GA account balance attributed to these customers, as a result. Alectra Utilities submits total Class A actual consumption for the Brampton RZ to the IESO on a monthly basis as part of the monthly RPP vs. Market Claim submission.

Class B non-RPP Customers: Class B non-RPP customers are billed by Alectra Utilities for the Brampton RZ throughout the month. These customers pay the spot market price for energy – either the Weighted Average Hourly Spot price ("WAHSP") or the Hourly Ontario Energy Price ("HOEP"); and the GA. Alectra Utilities bills its Brampton RZ Class B non-RPP customers using the IESO's 1st estimate for GA for the month which is published by the IESO on the last business day of the preceding month. Alectra Utilities pays the IESO Class B GA for the Brampton RZ based on its actual Class B volume at the actual Class B rate. No further settlement with the IESO is required. Any difference between GA revenues and GA costs are recorded in the GA variance account to be recovered from or refunded to Class B non-RPP customers. Alectra Utilities allocates the Class B GA charged by the IESO for the Brampton RZ to its RPP and non-RPP customers based on consumption. Class B non-RPP consumption is equal to the consumption for all customers billed at spot pricing (interval metered and non-interval metered) less the consumption for Class A customers. Billing statistics data is used to estimate consumption for Class B non-RPP customers. The determination of Class B RPP consumption is discussed in further detail, below.

Class B RPP Customers: Brampton RZ Class B RPP customers are billed by Alectra Utilities throughout the month at RPP TOU or Tiered Rates. The difference between how much Alectra Utilities recovers from Brampton RZ RPP customers at these rates and the amount Alectra Utilities pays for the commodity supply in the wholesale marketplace for the Brampton RZ to the IESO, is recorded and managed in an account by the IESO.

On a monthly basis, this difference is settled with the IESO via the RPP vs. Market Price claim. The amount submitted is reflected on the following month's IESO invoice as either a debit (Alectra Utilities collected more revenue from RPP customers in the Brampton RZ than it paid for electricity) or a credit (Alectra Utilities collected less revenue from RPP customers in the Brampton RZ than it paid for electricity). Alectra Utilities compares the amount collected from

RPP customers for the Brampton RZ (kWh billed at TOU or Tiered Pricing) to the amount it pays to the IESO for electricity for that same volume, to determine this amount. There are two components to the RPP vs. Market Price claim:

1. Estimated RPP settlement amount for the current month; and
2. A true-up adjustment to the RPP settlement amount for the prior month (the difference between the actual and estimated RPP settlement amounts for the prior month)

1. Estimated RPP settlement amount for the current month

- Estimated total kWhs of commodity purchased for the month and the associated dollars based on Spot Market Price.
- The billing statistics for the current month of the prior year are used as the estimate of the percentage of volumes billed to customers at Spot Market Prices. This percentage is used to allocate the volumes billed to customers based on Spot Market prices, and those billed on RPP prices.
- The volumes billed to customers at RPP rates is then allocated across the various RPP price Tiers and TOU price blocks. The kWh allocation %s are estimated based on the actual percentage ratios from the billing statistics for the current month of the prior year.
- The quantities for each Tier/TOU price block are multiplied by the average spot market price purchased.
- As the actual wholesale GA rate for the month is not available at the time of the calculation, the 2nd estimate GA rate provided by IESO for the current month is used to calculate the GA portion of the settlement calculations.
- The Energy at Spot Market Price and the GA represents an estimate of what the IESO will bill Alectra Utilities for the Brampton RZ for the month.
- The OEB approved RPP prices are multiplied by the volumes estimated for each of the Tier/TOU price blocks and represents an estimate of the amount to be billed to RPP customers for the commodity and GA.

- The current month estimated Settlement is the difference between 1) the estimated Commodity plus GA to be billed by the IESO for the RPP customers, and 2) the estimated power billed by Alectra Utilities Brampton RZ to RPP customers.

2. True-up adjustment to the RPP settlement amount

- The billing statistics for the prior month of the current year for the percentage of volumes billed to customers at Spot Market Prices is used,
- The billing statistics for the prior month of the current year for the actual kWh allocation %'s for each Tier/TOU price Block are used, and
- The actual Class B GA rate for the prior month is used.
- The actual RPP claim calculated for the prior month is compared to the prior month's estimate to determine the true-up adjustment.

Table 66 – Timing of RPP vs. Market Claim True-up – Brampton RZ

Period Covered	Original Claim	Actual Claim True-Up
April	April	May

CAPITALIZATION POLICY

Alectra Utilities implemented a new capitalization policy in 2017 (as a result of the consolidation, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones.

IFRS 10 *Consolidated Financial Statements,* states that uniform accounting policies have to be adopted for like transactions in a group of companies. Further, IFRS 3 *Business Combinations* prescribes that the accounting policies of the parties to the merger should align to the acquirer's policy. IFRS 3 provides guidance on identifying the acquirer by assessing the relative voting rights in the combined entity after the merger; the acquirer being the combining entity whose owners, as a group, receive the largest portion of voting rights in the combined entity.

For the predecessor companies that formed Alectra Utilities, PowerStream is the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities adopted the PowerStream capitalization policy.

The OEB established three new deferral accounts to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs, in Procedural Order No. 3, as part of Alectra Utilities' 2018 EDR Application proceeding. In the 2018 EDR Application Decision, the OEB stated that: "*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, 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.* Further, the OEB stated that: "*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*[11]*."*

The total 2017 net impact of the financial differences arising from the change to Alectra Utilities' capitalization policy in the Brampton RZ is a reduction in revenue requirement of $1.2MM.

The net impact of the capitalization policy change includes the following items:

- The actual impact on OM&A expenditures in each year following the change in capitalization policy until rebasing;
- The actual impact on depreciation expense over the life of the underlying assets as a result of the increase/decrease in capitalization costs;
- The impact on income tax or PILs for the amount paid to taxation authorities; and
- The annual return on the cumulative impact from the annual change in capitalization.

Alectra Utilities proposes to recover this amount over a one year period from all customers in the Brampton rate zone. Tables 67 to 70 below provide the total 2017 impact of the change in capitalization policy for the Brampton rate zone.

Table 67 – Capitalization Policy Total Net Financial Impact Brampton Rate Zone

Capitalization Policy Impact	2017 Actual
Total OM&A Impact	($1,830,532)
Total Depreciation Impact	$22,882
Total PILs Impact	$465,687
Total Return on Capital Impact	$130,252
Total Net Impact	**($1,211,711)**

[11] EB-2017-0024 pg. 81

Table 68 – Capitalization Policy Total OM&A and Depreciation Impact Brampton RZ

OM&A Impact – Brampton RZ	2017 Actual
Direct Labour Costs	($849,888)
Benefit Costs	($576,904)
Material Handling Costs	($403,740)
Fleet Costs	$0
Total Impact	**($1,830,532)**

Depreciation Impact – Brampton RZ	2017 Actual
Depreciation Expense	$22,882
Total Depreciation Impact	**$22,882**

Table 69 – Capitalization Policy Total PILs Impact Brampton Rate Zone

PILs Impact – Brampton RZ	2017 Actual
OM&A Impact	($1,830,532)
Depreciation Impact	$22,882
NIBT	($1,807,650)
Add back: Depreciation	($22,882)
Deduct: CCA	$73,221
Taxable income	($1,757,311)
Income tax @ 26.5%	**$465,687**

Table 70 – Capitalization Policy Total Return on Capital Impact Brampton Rate Zone

Return on Capital_BRZ	2017 Actual
Increased capitalization	($1,830,532)
Depreciation Expense	$22,882
Increased Capital in Rate Base	($1,807,650)
Deemed ShortTerm Debt %	4.00%
Deemed LongTerm Debt %	56.00%
Short Term Interest	2.16%
Long Term Interest	6.07%
Deemed ShortTerm Debt %	($72,306)
Deemed Long Term Debt %	($1,012,284)
Short Term Interest	($1,562)
Long Term Interest	($61,446)
Return on Rate Base - Interest	($63,007)
Deemed Equity	($723,060)
	9.30%
Return on Capital - Equity	($67,245)
Return on Capital	**$130,252**

Alectra Utilities is seeking Board approval for the capitalization policy rate riders, for the Brampton RZ, identified in Table 71 to recover the revenue requirement of $1,211,711 identified in Table 67 above. The revenue requirement has been allocated to rate classes based on the current allocation of revenue as provided in the Capitalization Policy Rate Rider Model for the Brampton RZ filed as Attachment 19. The revenue requirement for the residential class will be recovered via a fixed rate rider as per the OEB's letter issued July 16, 2015 (EB-2012-0410). Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in Attachment 19.

Table 71 – Capitalization Policy Rate Riders – Brampton RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.38	$0.00	kWh
General Service Less Than 50 kW	$0.41	$0.0003	kWh
General Service 50 To 699 kW	$2.04	$0.0463	kW
General Service 700 To 4,999 kW	$18.45	$0.0538	kW
Large Use	$76.77	$0.0407	kW
Unmetered Scattered Load	$0.02	$0.0003	kWh
Street Lighting	$0.04	$0.1882	kW
Embedded Distributor	$67.87	$0.00	kWh
Distributed Generation	$1.70	$0.00	kWh

RENEWABLE GENERATION CONNECTION RATE PROTECTION

In the 2015 Cost of Service Rate Application (EB-2014-0083), the Board approved Hydro One Brampton's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2015 to 2019. Hydro One Brampton's DSP was reviewed by the OEB and its funding requests for eligible investments for 2015 to 2019 were approved by the OEB.

Alectra Utilities is requesting to collect renewable generation funding of $145,922 in 2019 or $12,160 per month from all provincial ratepayers, as identified in Table 72 below for the Brampton RZ.

Table 72 – Green Energy Plan Rate Protection Benefit and Charge in 2019– Brampton RZ

	2019	
Description	**Yearly**	**Monthly**
Renewable Enabling Improvement Investments	$113,770	$ 9,481
Renewable Expansion Investments	$ 32,152	$ 2,679
Total Recovery:	**$145,922**	**$ 12,160**

DISPOSITION OF LRAM VARIANCE ACCOUNT

Alectra Utilities is applying for disposition of the balance in the LRAMVA account resulting from its Conservation and Demand Management ("CDM") activities in 2016 in the Brampton RZ. The total amount requested for disposition is a debit of $722,462 including forecasted carrying charges of $24,409 through to December 31, 2018. Actual savings from CDM activities for 2016 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Brampton's most recent application for the recovery of lost revenues due to CDM activities was filed in Hydro One Brampton's 2017 IRM Application (EB-2016-0080). In that proceeding, the Board approved Hydro One Brampton's request to recover lost revenues from CDM activities in 2013 through 2015, and the related persistence through this period.

Lost Revenue Adjustment Mechanism for 2011-2014 and 2015-2020

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive to the OEB (the "Directive") to establish electricity and conservation and demand management targets to be met by licensed electricity distributors over a four year period commencing January 1, 2011. The Minister of Energy and Infrastructure included guidance to the OEB that lost revenues that result from CDM programs should not act as a disincentive to a distributor to promote CDM activities.

On April 26, 2012, in response to the Directive, the OEB issued a new set of *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets that are a condition of licence. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period.

The OEB authorized the establishment of an LRAM variance account ("LRAMVA") to record, at the customer rate-class level, the difference between:

(iii) the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for CDM programs, and

(iv) the level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

The variance calculated from the comparison will result in a credit or a debit to the ratepayer at the customer class level in the LRAMVA.

On March 31, 2014, the Ministry of Energy and Infrastructure, in response to the Government of Ontario's Long-Term Energy Plan ("LTEP"), issued a directive to the OEB ("the Conservation Directive") to promote CDM, including amending the licences of electricity distributors and establishing CDM Requirement guidelines (the "2015 CDM Guidelines").

On December 19, 2014, the OEB issued *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* (EB-2014-0278) ("2015 CDM Guidelines") which amended the electricity distribution licences of all electricity distributors to include a condition that requires the distributors to make CDM programs available to each customer segment in their service area and to report annual CDM results to the IESO. The Board also requires that electricity distributors work with natural gas distributors and the IESO in coordinating and integrating electricity conservation and natural gas demand side management programs. The 2015 CDM Guidelines also confirmed the continuation of the LRAM mechanism to compensate distributors for lost revenues resulting from CDM programs for the 2015 to 2020 period.

On May 19, 2016, the OEB issued an *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs,* on the calculation of the LRAMVA in respect of peak demand savings. In this report, the OEB determined that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year.

The OEB also indicated that peak demand savings from Demand Response ("DR") programs should generally not be included within the LRAMVA calculation.

LRAM Calculations

The OEB has identified that distributors can apply for disposition of the balance in the LRAMVA as part of their cost of service applications and may apply for disposition on an annual basis, as part of their IRM application, if the balance is deemed significant by the applicant. Alectra Utilities is requesting approval for recovery of lost revenues of $722,462, including carrying charges, which is above the materiality threshold for the Brampton RZ. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $340,090.

Alectra Utilities has determined the LRAM amount for the Brampton RZ in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines and its 2016 Updated Policy for the calculation of LRAMVA, in respect of peak demand savings. Alectra Utilities has completed the Version 2.0 of the LRAMVA work form for the Brampton RZ provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA work form is filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016, and is provided in Attachment 20. Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Brampton RZ in its lost revenue calculation in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities provides the following information for the Brampton RZ:

(i) Alectra Utilities has used the most recent input assumptions available at the time of the program evaluation when calculating the lost revenue amount for the Brampton RZ; and

(ii) Alectra Utiltiies has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of the lost revenue calculation for the Brampton RZ. The IESO's Final Annual Verified Results for 2016 is filed as Attachment 21.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2017. Alectra Utilities proposes to dispose of its 2017 LRAMVA balance for the Brampton RZ in a future rate proceeding. Alectra Utilities identifies that the balance in Account 1568, LRAMVA, as identified in Tab "3. Continuity Schedule" does not match the amount being requested for disposition due to the exclusion of the 2017 balances as mentioned previously.

Alectra Utilities is seeking recovery of lost revenues for the Brampton RZ for the period January 1, 2016 to December 31, 2016 resulting from the following:

(i) 2013 to 2015 CDM persistence savings in 2016; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2016.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 73 identified below.

Table 73 – Distribution Volumetric Rates – Brampton RZ

Year	Residential	GS<50 kW	General Service 50 To 699 Kw	General Service 700 To 4,999 Kw	Large Use
	kWh	kWh	kW	kW	kW
2016	$0.0118	$0.0164	$2.7940	$3.2434	$2.4556

Alectra Utilities' Brampton RZ's LRAMVA threshold approved in its 2015 Cost of Service Application (EB-2014-0083) is used as the comparator against actual savings for the lost revenue calculation for 2016. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 74 identified below.

Table 74 – LRAMVA Thresholds – Brampton RZ

Year	LRAMVA Threshold	Residential	GS<50 KW	General Service 50 To 699 KW	General Service 700 To 4,999 KW
		kWh	kWh	kW	kW
2015	2015	12,486,005	1,448,724	64,526	35,242
2016	2015	12,486,005	1,448,724	64,526	35,242

Alectra Utilities has calculated carrying charges on the LRAM amounts for the Brampton RZ from January 1, 2016 to December 31, 2018 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $722,462, representing a principal balance of $698,054 and carrying charges of $24,409.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 75 and 76 below for the Brampton RZ, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 75 – LRAMVA Totals by Rate Class – Brampton RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$256,587	$8,972	$265,559
GS<50 kW	kWh	$262,901	$9,193	$272,093
General Service 50 To 699 KW	kW	$93,698	$3,276	$96,974
General Service 700 To 4,999 KW	kW	$51,606	$1,805	$53,411
Large Use	kW	$33,261	$1,163	$34,424
Total		**$698,054**	**$24,409**	**$722,462**

1 **Table 76 – LRAMVA by Year and Rate Class – Brampton RZ**

Description	Residential	GS<50 kW	General Service 50 To 699 KW	General Service 700 To 4,999 KW	Large Use	Total
	kWh	kWh	kW	kW	kW	
2016 Actuals	$403,922	$286,660	$273,983	$165,911	$33,261	$1,163,737
2016 Forecast	($147,335)	($23,759)	($180,285)	($114,304)	$0	($465,683)
2016 LRAM Balance	**$256,587**	**$262,901**	**$93,698**	**$51,606**	**$33,261**	**$698,054**
Carrying Charges	**$8,972**	**$9,193**	**$3,276**	**$1,805**	**$1,163**	**$24,409**
Total LRAMVA Balance	**$265,559**	**$272,093**	**$96,974**	**$53,411**	**$34,424**	**$722,462**

2

3 The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are
4 identified in Table 77 below and included in Tab “8. Calculation of Def-Var RR” in the IRM
5 Model.

6 **Table 77 – LRAMVA Rate Riders – Brampton RZ**

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.00	$0.0002	kWh
GS<50 kW	$0.00	$0.0008	kWh
General Service 50 To 699 KW	$0.00	$0.0309	kW
General Service 700 To 4,999 KW	$0.00	$0.0269	kW
Large Use	$0.00	$0.0527	kW

TAX CHANGES

The OEB policy, as described in the Board'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 their OEB approved base rates. If applicable, these amounts will be refunded to customers over a 12-month period.

In this application, Alectra Utilities is not applying for a rate rider associated with the 50/50 sharing of the legislated tax change impact as Alectra Utilities' corporate tax rate of 26.50% is not expected to change in 2019. Therefore, there is no shared tax savings in this application.

SUMMARY OF BILL IMPACTS

A summary of bill impacts for the typical customer by rate class is presented in Tables 78 to 80 below. Attachment 16 provides a detailed summary of the bill impacts for each customer class for 2019.

Table 78 – Distribution Bill Impacts by Rate Class – Brampton RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ 0.57	2.3%
GS<50	kWh	2,000	$ 2.84	4.7%
GS 50-699 kW	kW	500	$ 52.06	3.3%
GS 700-4,999 kW	kW	1,432	$ 158.92	2.7%
Large User	kW	20,000	$ 2,322.12	4.2%
Street Lighting	kW	4,000	$ 2,939.57	2.1%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

Table 79 – Distribution Bill and Rate Rider Impacts by Rate Class – Brampton RZ

Distribution Bill and All Rate Rider Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.36)	(1.4)%
GS<50	kWh	2,000	$ 0.36	0.6%
GS 50-699 kW	kW	500	$ 4.83	0.4%
GS 700-4,999 kW	kW	1,432	$ 10.85	0.2%
Large User	kW	20,000	$ (10,257.88)	(22.9)%
Street Lighting	kW	4,000	$ 2,113.79	1.5%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

1 **Table 80 – Total Bill Impacts by Rate Class (before HST) – Brampton RZ**

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.67)	(0.7)%
GS<50	kWh	2,000	$ (0.47)	(0.2)%
GS 50-699 kW	kW	500	$ (59.67)	(0.2)%
GS 700-4,999 kW	kW	1,432	$ (191.45)	(0.2)%
Large User	kW	20,000	$ (13,486.13)	(1.0)%
Street Lighting	kW	4,000	$ 1,265.89	0.3%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

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CONCLUSION

Alectra Utilities respectfully requests that the Board approve the relief sought for the Brampton RZ in this Application.

POWERSTREAM RATE ZONE

MANAGER'S SUMMARY

Alectra Utilities is applying for distribution rates and other charges in the PowerStream RZ, pursuant to a Price Cap IR, effective January 1, 2019. This application impacts customers in the Cities of Barrie, Markham, Vaughan and the Towns of Aurora, Richmond Hill, Alliston, Beeton, Bradford West Gwillimbury, Penetanguishene, Thornton, and Tottenham.

Alectra Utilities has completed the IRM Model for the PowerStream RZ and will update the Application to include the 2019 IRM Rate Generator Model ("2019 IRM Model") once it is available from the OEB. This Application has been prepared in accordance with the updated *Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications* (the "Chapter 3 Filing Requirements"), dated July 20, 2017, including the key OEB reference documents listed therein, the Letter from the Board to Licensed Electricity Distributors *re: I. Updated Filing Requirements; and, II. Process for 2018 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications,* dated July 20, 2017.

Alectra Utilities also applies for incremental capital funding for the Powerstream RZ in accordance with the OEB's: Chapter 3 Filing Requirements; the MAADs Handbook; the OEB's *Handbook for Utility Rate Applications* (the "Rate Handbook"), dated October 13, 2016; the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014; and the subsequent *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016.

Relief Sought in This Application

Alectra Utilities is seeking Board approval for the following in the PowerStream RZ:

i. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

ii. The continuation of the implementation of the new distribution rate design for residential electricity customers;

iii. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

iv. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

v. An adjustment to the retail transmission service rates effective January 1, 2019;

vi. 2019 Renewable Generation Connection Rate Protection from provincial ratepayers;

vii. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period;

viii. Incremental capital rate riders effective January 1, 2019 until the next rebasing application; and

ix. Current (i.e., 2018) rates provided in Attachment 23 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

ANNUAL PRICE CAP ADJUSTMENT MECHANISM

As part of the RRFE, the OEB initiated a review of utility performance per the *Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379)" proceeding. As part of this proceeding, the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board, "*Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board*". The original PEG Report was issued on May 3, 2013, and established the parameters for use to determine the Price Cap Index for the 4th Generation IRM including: a productivity factor of 0.00%, the approach to determine the Industry Specific Inflation Factor (replacing the 3rd Generation IRM GDP-IPI inflation factor), and the initial stretch factor assignments.

Stretch Factor

The Stretch Factor assignments for 2019 IRM filers have not yet been updated by the Board. Alectra Utilities has used Stretch Factor of 0.3% for the PowerStream RZ in this Application, in accordance with the most recent PEG Report, issued on August 17, 2017. The August 2017 report placed Alectra Utilities' PowerStream RZ in Group III for the purpose of calculating stretch factors for 2018.

Inflation Factor

The Industry Specific Inflation Factor for 2019 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor for the PowerStream RZ published for 2018 IRM filers; i.e., 1.2%, as a proxy for 2019.

Alectra Utilities will update the IRM Model with the 2019 stretch factor and inflation factor, in order to calculate the Price Cap Index, once these factors are published by the Board.

The Price Cap Index, as determined in the IRM Model filed as Attachment 25 is 0.9%, is identified in Table 81, below.

Table 81 – Calculation of Price Cap Index – PowerStream RZ

Factor	%
Inflation Factor	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.30%
Price Cap Index	**0.90%**

The Price Cap Index of 0.9% has been applied to the 2018 Service Charges and Distribution Volumetric Rates by rate class to determine Alectra Utilities 2019 Service Charges and Distribution Volumetric Rates for the PowerStream RZ. The related 2019 Proposed Tariff of Rates and Charges for the PowerStream RZ is filed as Attachment 23.

RATE DESIGN FOR RESIDENTIAL ELECTRICITY CUSTOMERS

On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Customers*, which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year period commencing in 2016 and ending in 2019.

The Board directed that *"Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral."*

PowerStream incorporated the first year transition adjustment in its proposed rates for 2017, in a manner consistent with OEB policy. As per the Decision and Order for the PowerStream 2016 Rate Application (EB-2015-0003), the Board accepted PowerStream's proposal to transition to a fully fixed monthly distribution charge over four years starting in 2017 and ending in 2020.

Alectra Utilities incorporated the second year transition adjustment in its proposed rates for 2018, for the PowerStream RZ, in a manner consistent with OEB policy. As per the Decision and Order for the 2018 annual filing, the Board approved the proposed increase in the fixed distribution rate and corresponding decrease in the variable distribution rate for the residential class in 2018.

Alectra Utilities has incorporated the third year transition adjustment for the PowerStream RZ in its proposed rates for 2019. The calculation of the proposed residential fixed and variable rates is identified in Tab 17. Rev2Cost-GDPIPI of the IRM Model filed as Attachment 25.

The Board instructed distributors that, for the purposes of implementing the new fixed rate design, a 10% test will be applied to customers who consume much less electricity than the typical residential customers.

This will allow any mitigation plans to be tailored to those customers who use the least power and whose bills will likely increase due to the shift in the fixed rates. If a customer at the 10^{th} consumption percentile level of electricity has a bill impact of 10% or higher, the distributor must make a proposal for a rate mitigation plan.

Alectra Utilities confirms that the Residential monthly service charge increase of $3.20 is below the threshold of $4 per month identified in the Board's policy. Accordingly, rate mitigation is not necessary since a customer at the lowest decile of electricity consumption will not have a bill impact of 10% or higher.

Alectra Utilities has followed the Board's direction to assess the combined effect of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service for the PowerStream RZ, by evaluating the total bill impact for a residential customer at the 10th consumption percentile. The following is a description of the method that Alectra Utilities used to derive the 10th consumption percentile for the PowerStream RZ.

1. Alectra Utilities ranked the annual kWh usage of active residential customers who consumed electricity at the location for a minimum of twelve months from the lowest to the highest number of kWhs for the PowerStream RZ.
2. Alectra Utilities looked at the consumption level of the customer whose rank was 1/10th of the total number of customers ranked for the PowerStream RZ.
3. Alectra Utilities calculated the 10th percentile customer's average monthly usage by dividing the annual consumption by 12 months for the PowerStream RZ.
4. Alectra Utilities determined the number of monthly kWhs at the 10th consumption percentile to be 309 kWh for the PowerStream RZ.

Alectra Utilities has provided in Table 82 below, the bill impact for a Residential customer who consumes 309 kWh monthly. The monthly service charge increased by $3.20 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 2.57%.

Table 82 – 10th Consumption Percentile Residential Customer Bill Impact (309 kWh) – PowerStream RZ

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 309 kWh
Current Loss Factor 1.0369
Proposed/Approved Loss Factor 1.0369

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 21.63	1	$ 21.63	$ 24.83	1	$ 24.83	$ 3.20	14.79%
Distribution Volumetric Rate	$ 0.0088	308.871	$ 2.72	$ 0.0044	308.871	$ 1.36	$ (1.36)	-50.00%
Fixed Rate Riders	$ 0.25	1	$ 0.25	$ 0.31	1	$ 0.31	$ 0.06	24.00%
Volumetric Rate Riders	$ -	308.871	$ -	$ 0.0003	308.871	$ 0.09	$ 0.09	
Sub-Total A (excluding pass through)			**$ 24.60**			**$ 26.59**	**$ 1.99**	**8.10%**
Line Losses on Cost of Power	$ 0.0820	11	$ 0.93	$ 0.0820	11	$ 0.93	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0028	309	$ (0.86)	-$ 0.00380	309	$ (1.17)	$ (0.31)	35.71%
Low Voltage Service Charge	$ 0.0005	309	$ 0.15	$ 0.0005	309	$ 0.15	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.75	1	$ 0.75	$ 0.57	1	$ 0.57	$ (0.18)	-24.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 25.57**			**$ 27.08**	**$ 1.50**	**5.88%**
RTSR - Network	$ 0.0075	320	$ 2.40	$ 0.0073	320	$ 2.34	$ (0.06)	-2.67%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0040	320	$ 1.28	$ 0.0040	320	$ 1.28	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 29.26**			**$ 30.70**	**$ 1.44**	**4.92%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	320	$ 1.15	$ 0.0036	320	$ 1.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	320	$ 0.10	$ 0.0003	320	$ 0.10	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	201	$ 13.05	$ 0.0650	201	$ 13.05	$ -	0.00%
TOU - Mid Peak	$ 0.0940	53	$ 4.94	$ 0.0940	53	$ 4.94	$ -	0.00%
TOU - On Peak	$ 0.1320	56	$ 7.34	$ 0.1320	56	$ 7.34	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 56.08**			**$ 57.52**	**$ 1.44**	2.57%
HST	13%		$ 7.29	13%		$ 7.48	$ 0.19	2.57%
8% Provincial Rebate	-8%		$ (4.49)	-8%		$ (4.60)	$ (0.12)	2.57%
Total Bill on TOU			**$ 58.88**			**$ 60.40**	**$ 1.51**	2.57%

ELECTRICITY DISTRIBUTION RETAIL TRANSMISSION SERVICE RATES

The Board's *Guideline for Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") (G-2008-0001) was issued June 28, 2012. On January 25 2018, the OEB issued its Decision and Order in respect of the 2018 Uniform Transmission Rates ("UTRs") (EB-2017-0359). On December 21, 2016, the OEB issued its Decision and Order in respect of Hydro One Networks Inc. ("HONI") application for electricity distribution rates and other charges beginning January 1, 2017, which contain HONI's sub transmission rates ("STRs") at page 10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 83, below.

Table 83 – Current Board-Approved UTRs and STRs – PowerStream RZ

UTRs	$
Network Service Rate	$3.61
Line Connection Service Rate	$0.95
Transformation Connection Service Rate	$2.34
STRs	**$**
Network Service Rate	$3.1942
Line Connection Service Rate	$0.7710
Transformation Connection Service Rate	$1.7493

Alectra Utilities has updated Tabs 11-15 of the IRM Model for the PowerStream RZ filed as Attachment 25 to incorporate i) the most recent UTRs and STRs approved by the Board; and ii) an update to demand in the PowerStream RZ from 2016 to 2017 actual values. The RTSRs are calculated in Tab 16 of the IRM Model.

Alectra Utilities will update the RTSRs for the PowerStream RZ should the actual UTRs and STRs be approved prior to the OEB issuing the final rate order for this application.

REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative (*EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met. Consistent with a Letter from the Board to Licensed Electricity Distributors re: *Process for 2015 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*, dated July 25, 2014 distributors may also elect to dispose of Group 1 account balances below the threshold.

Group 1 accounts consist of the following Uniform System of Accounts ("USoA"):

- 1550 - Low Voltage Account;
- 1551 - SME Charge Account;
- 1580 - RSVA Wholesale Market Service Charge Account;
- 1584 - RSVA Retail Transmission Network Charge Account;
- 1586 - RSVA Retail Transmission Connection Charge Account;
- 1588 - RSVA Power Account;
- 1589 - RSVA Global Adjustment Account;
- 1590 - Recovery of Regulatory Asset Balances Account (if applicable); and
- 1595 - Disposition and Recovery/Refund of Regulatory Balances Account.

The Group 1 balances for the PowerStream RZ as of December 31, 2017, in the amount of ($29,425,076), have been adjusted for the following items to determine the amount for disposition of ($3,231,993) as identified in Table 84 below:

- Only residual balances in Account 1595 for which rate riders have expired are included;

- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition as directed in the OEB's letter on the "*Guidance on the Disposition of Accounts 1588 and 1589*", dated May 23, 2017. For the PowerStream RZ an adjustment of $4,413,063 and ($430,861) has been made to Accounts 1588 and 1589, respectively to reflect RPP settlement true-up claims for 2017 that were settled in 2018. These amounts have been entered into the IRM model, Tab "3. Continuity Schedule" Column "Principal Adjustment during 2016". See Table 84 below for a summary of this adjustment. Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- Only Class B Capacity Based Recovery ("CBR") amounts are to be disposed of through this rate proceeding, as directed by the OEB in its *Accounting Guidance on Capacity Based Recovery* issued July 25, 2016; and
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e. the amount for disposition includes 2018 projected carrying charges).

Table 84 – Group 1 Account Balances for Disposition – PowerStream RZ

Description	Amount
Group 1 Account Balances as of December 31, 2017	**($29,425,076)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers	($22,305,316)
RPP Settlement True-up Claims Adjustment	$3,982,202
Add Projected Carrying Charges	($56,845)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	($37,590)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($3,231,993)**

Alectra Utilities has computed the disposition threshold for the PowerStream RZ, based on the adjusted Group 1 balances to be ($0.0004)/kWh, as identified in Table 85, below. Alectra Utilities requests disposition of its Group 1 account balances for the PowerStream RZ in this Application.

Table 85 - Calculation of Disposition Threshold – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	$6,086,098
Smart Meter Entity Charge	1551	($648,078)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	$1,915,509
RSVA - Wholesale Market Service Charge excluding CBR	1580	($34,531,120)
RSVA - Retail Transmission Network Charge	1584	($13,336,137)
RSVA - Retail Transmission Connection Charge	1586	$1,663,980
RSVA - Power	1588	$3,614,300
RSVA - Global Adjustment	1589	$5,911,720
Disposition and Recovery/Refund of Regulatory Balances	1595	($101,347)
Group 1 Account Balances as of December 31, 2017		**($29,425,076)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers		($22,305,316)
RPP Settlement True-up Claims Adjustment		$3,982,202
Add Projected Carrying Charges		($56,845)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		($37,590)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($3,231,993)**
2017 kWhs		8,235,912,292
Threshold Test $/kWh		**($0.0004)**

Alectra Utilities has completed Tab 3. Continuity Schedule of the IRM Model for the PowerStream RZ filed as Attachment 25. Alectra Utilities has reconciled the Group 1 balances filed in the 2017 RRR for the PowerStream RZ, section 2.1.7 as identified in Table 86 below. Alectra Utilities confirms that the last Board approved balance of ($22,305,316) for PowerStream RZ has been transferred to Account 1595 (as identified in Alectra Utilities' 2018 EDR Application EB-2017-0024). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2017 RRR, section 2.1.5.4. Alectra Utilities relied on the Board's prescribed interest rate to calculate carrying charges on the deferral and variance account balances for the PowerStream RZ. The prescribed interest rate of 1.5% for 2018 Q1 and 1.89% for 2018 Q2-Q4 were used to calculate forecasted interest for 2018. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 86 – Deferral and Variance Account Reconciliation – PowerStream RZ

Account Description	Account	Principal Amounts as of Dec 31, 2017	Carrying Charges to Dec 31, 2017	Principal Disposition during 2018 - instructed by Board EB-2017-0024	Interest Disposition during 2018 - instructed by Board EB-2017-0024	Projected Carrying Charges to Dec 31, 2018	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims 2017 Reversal	Projected Carrying Charges to December 31, 2018	1595 Balances Not Claimed in 2019	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	5,983,822	102,277	(4,477,534)	(117,006)	27,000	1,518,559				1,518,559
Smart Meter Entity Charge	1551	(642,269)	(5,809)	252,810	6,561	(6,981)	(395,688)				(395,688)
RSVA - Wholesale Market Service Charge - CBR B	1580	1,863,100	52,410	(1,947,271)	(63,569)	(1,509)	(96,840)				(96,840)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(33,873,012)	(658,107)	25,885,605	754,948	(143,174)	(8,033,741)				(8,033,741)
RSVA - Retail Transmission Network Charge	1584	(13,164,431)	(171,706)	6,495,670	166,419	(119,538)	(6,793,585)				(6,793,585)
RSVA - Retail Transmission Connection Charge	1586	1,613,442	50,538	(2,623,509)	(72,272)	(18,105)	(1,049,907)				(1,049,907)
RSVA - Power	1588	3,615,019	(720)	(1,047,973)	(38,944)	46,014	2,573,397	4,413,063	79,104		7,065,564
Sub-total not including RSVA Power Global Adjustment		(34,604,330)	(631,118)	22,537,798	636,138	(216,293)	(12,277,804)	4,413,063	79,104		(7,785,638)
RSVA - Power Global Adjustment	1589	5,767,704	144,016	(890,272)	(116,647)	87,428	4,992,229	(430,861)	(7,723)		4,553,645
Total including RSVA Power Global Adjustment		(28,836,626)	(487,102)	21,647,527	519,491	(128,865)	(7,285,575)	3,982,202	71,381		(3,231,993)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	2	(21,764)	(2)	21,764	-	(0)			(0)	-
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	7,318	241	(7,318)	(280)	-	(39)			(39)	-
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	336	47	(336)	(49)	-	(2)			(2)	-
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	12,466	153,423	(12,466)	(153,489)	-	(66)			(66)	-
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	35,642	(289,058)	0	290,474	639	37,697			37,697	-
Total 1595		55,763	(157,111)	(20,122)	158,420	639	37,590	-	-	37,590	-
Total Group 1		**(28,780,863)**	**(644,213)**	**21,627,405**	**677,911**	**(128,226)**	**(7,247,986)**	**3,982,202**	**71,381**	**37,590**	**(3,231,993)**
Total Amount for Disposition		**(28,780,863)**	**(644,213)**	**21,627,405**	**677,911**	**(128,226)**	**(7,247,986)**	**3,982,202**	**71,381**	**37,590**	**(3,231,993)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances in the PowerStream RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year"*.

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utiltiies has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Recovery ("CBR") Disposition

Alectra Utilities has also established separate rate riders to dispose of the global adjustment ("GA") and Capacity Based Response ("CBR") account balances for the PowerStream RZ. These rate riders are applicable for non-RPP Class B customers only. PowerStream Class A customers are invoiced the actual GA and as such none of the variance in the GA account balance should be attributed to these customers.

As discussed below in the section on the settlement process, Alectra Utilities bills its Class B interval metered customers for the PowerStream RZ based on the actual GA cost per kWh for the month. These customers are billed on a calendar month basis and at the time of billing the actual GA cost per kWh is available. This is done so that no variance is created.

Non-interval metered Class B customers are billed throughout the month, often when the final GA cost is not known. All non-interval metered Class B non-RPP customers are billed for GA based on the first estimate rate.

The result of this billing practice is that the entire GA variance of $4,553,645 for disposition is attributable to Class B non-RPP non-interval metered customers and not to Class B non-RPP interval metered customers.

Alectra Utilities has calculated rate riders to recover the entire GA variance balance from Class B non-RPP non-interval metered customers for the PowerStream RZ. The description for the rate rider has been worded to indicate that this applies only to non-RPP non-interval customers. The resulting rate riders are summarized in Table 87 below after the discussion on the movement of customers between Class A and Class B.

Alectra Utilities has started billing all Class B non-RPP customers for Global Adjustment at the 1st estimate rate effective January 1, 2018 for the PowerStream RZ, consistent with the other Alectra Utilities RZs.

As discussed above, none of the GA variance is attributable to the PowerStream RZ Class B interval metered customers. All of the customers moving between Class A and Class B are interval metered customers to whom the GA variance is not attributable.

The CBR variance is attributable to all Class B customers and should be apportioned to customers who move between Class B and Class A during the period in which the variances arose.

There were 101 PowerStream RZ customers that qualified as new Class A customers, effective July 1, 2017, under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid CBR as Class B customers up to and including June 30, 2017; and paid CBR as Class A customers from July 1, 2017 to December 31, 2017 These customers should be allocated only the portion of the GA and CBR account balances which accrued prior to their classification as Class A customers (i.e. from January 1, 2017 to June 30, 2017).

There were no PowerStream RZ customers that opted out of Class A effective July 1, 2016.

These CBR amounts will be settled through twelve equal adjustments to bills, as directed in the Chapter 3 Filing Requirements. These customers will not be charged the GA or CBR rate riders.

Table 87 below identifies the CBR balances disposed of through rate riders and specific bill adjustments.

The total GA balance to be disposed of is $4,553,645 which will be disposed of via rate rider; and $0 will be disposed of via specific bill adjustments.

The total CBR balance to be disposed of is ($96,840), of which ($91,231) will be disposed of via rate rider, and ($5,609) will be disposed of via specific bill adjustments. Tabs "7A. CBR Allocation_Class A".

Alectra Utilities requests disposition of its CBR balance of ($5,609) related to its new Class A customers (effective July 1, 2017) through the bill adjustments identified in the IRM Model for the PowerStream RZ.

Table 87 – Disposition of GA and CBR Balances – PowerStream RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	$4,553,645
Global Adjustment - New Class A Customers July 1/2017	$0
Global Adjustment - New Class B Customers July 1/2017	$0
Class B Non-RPP Customers only - GA Rate Rider	**$4,553,645**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	($91,231)
Capacity Based Recovery - New Class A Customers July 1/2017	($5,609)
Capacity Based Recovery - New Class B Customers July 1/2017	$0
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($96,840)**

A summary of the rate riders applicable to each group of customers is identified in Table 88 below.

Table 88 – Rate Riders by Customer Group – PowerStream RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2017 - Dec 31, 2017)	x	x			
Class B non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class A (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class A non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class B (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class B non-RPP (Jan 1, 2017 - Dec 31, 2017) Non-Interval Customers	x	x	x	x	
Class B non-RPP (Jan 1, 2017 - Dec 31, 2017) Interval Customers	x	x	x		
Class B RPP Customers	x	x	x		

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges.

Class A customers (who were Class A from January 1, 2017 to December 31, 2017) are charged the combined DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding GA and CBR.

Class A and Class B non-RPP customers, rows 3 and 4 in Table 88, who were Class A customers for only part of 2017, are charged the combined DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the CBR account balances.

Class B non-RPP non-interval metered customers who were Class B from January 1, 2017 to December 31, 2017 are charged DVA Rate Riders 1 and 2; the GA rate rider; and the CBR B Rate Rider.

Class B non-RPP interval metered customers who were Class B from January 1, 2017 to December 31, 2017 are charged DVA Rate Riders 1 and 2 and the CBR B Rate Rider.

Class B RPP customers are charged DVA Rate Riders 1 and 2; and the CBR B Rate Rider.

The Group 1 Disposition by customer group is identified in Table 89, below. The amount to be disposed of by rate rider is ($3,226,383) and the amount to be disposed of via customer specific bill adjustments is ($5,609).

Table 89 – Group 1 Disposition by Customer Group – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	$1,518,559
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($395,688)
Retail Transmission Network Charge	1584	($6,793,585)
Retail Transmission Connection Charge	1586	($1,049,907)
Disposition and Recovery/Refund of Regulatory Balances	1595	$0
All Customers - DVA Rate Rider 1		**($6,720,621)**
Power	1588	$7,065,564
Wholesale Market Service Charge excluding CBR	1580	($8,033,741)
All Customers ex WMPs - DVA Rate Rider 2		**($968,177)**
Wholesale Market Service Charge - CBR Class B	1580	($91,231)
Wholesale Market Service Charge - New Class A/B Customers July 1/2017		($5,609)
All Class B Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($96,840)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2017 -Dec 31/2017	1589	$4,553,645
Global Adjustment - New Class A/B Customers July 1/2017	1589	$0
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**$4,553,645**
Total (Repayment to)/Recovery from Customers		**($3,231,992)**
Disposition via Rate Rider		($3,226,383)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2017		$0
Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2017		($5,609)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2017 actual quantities reported in Alectra Utilities' 2017 RRRs for PowerStream have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 8 in the IRM Model filed as Attachment 25. Table 90 below summarizes the deferral and variance rate riders by class. As identified in the Chapter 3 Filing Requirements, *"Effective in 2017, the billing determinant and all the rate riders for the GA will be calculated on an energy basis (kWhs) regardless of the billing determinant used for distribution rates for the particular class."*

Table 90 – Proposed Rate Riders by Class – PowerStream RZ

Customer Class	Deferral/Variance		Deferral/Varian		Global		CBR B	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential Service Classification	(0.0010)				0.0018		(0.00001)	
General Service Less Than 50 kW Service Classification	(0.0009)				0.0018		(0.00001)	
General Service 50 To 4,999 kW Service Classification		(0.2953)		(0.0453)	0.0018			(0.00464)
Large Use Service Classification		(0.5809)			0.0000			(0.00001)
Unmetered Scattered Load Service Classification	(0.0009)				0.0018		(0.00001)	
Standby Power Service Classification		0.0000			0.0000			
Sentinel Lighting Service Classification		(0.3377)			0.0018			(0.00499)
Street Lighting Service Classification		0.0000			0.0018			(0.00470)

Alectra Utilities requests disposition of its adjusted Group 1 balances for the PowerStream RZ of ($3,226,383), identified in Table 89, through the rate riders identified in Table 90 above. Alectra Utilities also requests disposition of the CBR B rate rider to the fifth decimal place for the Enersource RZ. The OEB indicates in the Treatment of Negligible Rate Adders and Rate Riders on page 26 of the Chapter 3 Filing Requirements that:

> *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.*

However, Alectra Utilities proposes that the CBR B balance be cleared with a volumetric rate rider to five decimal places in 2018 for the Enersource RZ. 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. The OEB approved this approach in Alectra Utilities' 2018 EDR Application.

For a typical RPP Residential customer using 750 kWh/month, the total bill impact of the proposed Group 1 rate riders is a decrease of ($2.85) /month or (2.6%) on the total bill.

GA Analysis Workform

The GA Analysis Workform ("GA Workform") for the PowerStream RZ is filed as Attachment 26. The GA Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in the Account 1589 in a specific year is reasonable.

The principal activity in Account 1589 recorded in 2017 was $4,877,432 as identified in Table 91 below. The principal activity balance, after known adjustments of ($430,860) was $4,446,572 This is compared to the expected principal balance in Account 1589 of $1,842,016 as calculated in Attachment 26, which results in an unreconciled difference of ($2,604,555). This represents 0.67% of Alectra Utiltiies 2017 IESO purchases for the PowerStream RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 91 – GA Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	$4,877,432
Add Known Adjustments	($430,860)
Adjusted Principal Activity in RSVA(GA)	$4,446,572
Expected Principal Activity in RSVA(GA)	$1,842,016
Variance $	($2,604,555)
Total 2017 IESO Purchases	$390,034,880
Absolute Variance as a % of IESO Purchases	0.67%

SETTLEMENT PROCESS WITH THE IESO

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its settlements process with the IESO or host distributor. Distributors must specify the Global Adjustment rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. PowerStream provides its settlement process with the IESO below.

The manner in which Alectra Utilities settles with the IESO, for the PowerStream RZ, is provided in Table 92 below and depends on the following: (i) whether the customer is a Regulated Price Plan ("RPP") consumer; and (ii) whether the customer is a Class A or Class B consumer. It is not dependent on the rate class.

Table 92 – Settlement Process with the IESO – PowerStream RZ

Customer	GA Rate used for Billing	GA Rate used to Record Cost	Settlement Process	Consumption Estimates	Impact on GA Variance Account
Class A	Actual	Actual	Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	Class A consumption actuals are submitted to the IESO - actuals are known at the time of submission; therefore an estimate is not required	none
Class B non-RPP interval metered	Actual	Actual	Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	Consumption is calculated from customer bills using proration to determine the consumption falling within the target month	none
Class B non-RPP non-interval metered	1st Estimate	Actual	Alectra Utilities pays the IESO Actual GA and bills customers 1st estimate GA - no further settlement with the IESO is required		Difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP non-interval metered consumers on disposal of the GA Variance Account
Class B RPP	RPP Time-of-Use ("TOU") or Tiered Rates[1]	Actual	Alectra Utilities pays the IESO Actual GA and bills customers RPP rates - Alectra Utilities settles with the IESO on an monthly basis via the RPP vs. Market Price Claim[2]	RPP consumption is estimated and provided to the IESO as part of the RPP vs. Market Price Claim[2] provided to the IESO	none

1. GA is not billed separately for Class B RPP customers; incorporated into RPP Rates
2. RPP vs. Market Price Claim is discussed in further detail below

<u>Class A Customers</u>: The IESO publishes the actual GA for a month on the tenth business day of the following month. Class A customers are billed by Alectra Utilities for the PowerStream RZ around the 15th of each month, at which time the actual GA is known.

Alectra Utilities pays the IESO Class A GA actual based its customers' percentage contribution to the top five peak Ontario demand hours. No further settlement with the IESO is required. Alectra Utilities settles GA costs for the PowerStream RZ with Class A customers on the basis of actual costs and as such, none of the variance in the GA account balance is attributed to these customers, as previously mentioned. Alectra Utilities submits total Class A actual consumption to the IESO for the PowerStream RZ on a monthly basis. An estimate is not required since actual consumption is known at the time of submission.

Class B non-RPP interval metered Customers: Class B non-RPP interval metered customers are billed by Alectra Utilities for the PowerStream RZ based on the calendar month in the middle of the following month. These customers pay the Hourly Ontario Energy Price ("HOEP") price for energy; and the actual GA rate for the month. No further settlement with the IESO is required.

Class B non-RPP non-interval metered Customers: Class B non-RPP non-interval metered customers are billed by Alectra Utilities for the PowerStream RZ throughout the month. These customers pay the Weighted Average Hourly Spot price ("WAHSP") for energy; and the GA. Alectra Utilities bills its Class B non-RPP non-interval metered customers for the PowerStream RZ using the IESO's 1st estimate for GA for the month which is published by the IESO on the last business day of the preceding month.

Alectra Utilities pays the IESO Class B GA for the PowerStream RZ based on its Class B volume (RPP and non-RPP - both interval metered and non-interval metered) at the actual Class B rate. No further settlement with the IESO is required.

Alectra Utilities allocates the Class B GA billed by the IESO to its RPP and non-RPP customers for the PowerStream RZ based on consumption. Class B non-RPP consumption is calculated based on customer bills to determine the consumption for the target month. Class B GA cost is recorded as part of the cost of power - commodity. The portion relating to the Class B non-RPP customers is calculated and this amount is moved from the cost of power - commodity to the cost of power - global adjustment account.

The determination of Class B RPP consumption is discussed in further detail, below.

Class B RPP Customers: Class B RPP customers are billed by PowerStream RZ throughout the month at RPP TOU or Tiered Rates. The difference between how much PowerStream RZ recovers from RPP customers at these rates and the amount PowerStream RZ pays for the commodity supply in the wholesale marketplace to the IESO, is recorded and managed in an account by the IESO.

On a monthly basis, Alectra Utilities determines the balance in this account for the PowerStream RZ and submits it to the IESO ("the RPP vs. Market Price claim"). The amount submitted is reflected on the invoice as either a debit (Alectra Utilities collected more revenue from RPP customers for the PowerStream RZ than it paid for electricity) or a credit (Alectra Utilities collected less revenue from RPP customers for the PowerStream RZ than it paid for electricity). Alectra Utilities compares the amount collected from RPP customers (kWh billed at TOU or Tiered Pricing) to the amount it pays to the IESO for the PowerStream RZ for electricity for that same volume, to determine this amount. There are two components to the RPP vs. Market Price claim:

1. Estimated Claim for the Current Month
2. True-up of "Current Month (3-month lag)" Claim using Actual Billed Consumption

1. <u>Estimated Claim for the Current Month</u>

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available until three months post consumption due to a billing lag, Alectra Utilities estimates the eligible kWh from each RPP customer's most recent bill, for the PowerStream RZ, prorating based on the number of days to get the kWh consumption by each RPP rate level for the target month. Alectra Utilities uses this consumption to calculate the RPP revenue at RPP rates and the RPP cost to determine the RPP claim for the current month for the PowerStream RZ. RPP cost consists of the commodity cost and the GA cost. Commodity cost is calculated as the RPP kWhs multiplied by the weighted average hourly Ontario price based on the net system load for the target month. GA cost is calculated as the RPP kWhs multiplied by the GA 2nd estimate from IESO.

2. <u>True-up of "Current Month (3-month lag)" Claim using Actual Billed Consumption</u>

The original estimate of eligible kWh and associated dollar amounts are based on the customers' bills and best cost information available at the time of filing the claim including GA cost at 2nd estimate rather than actual GA cost. Alectra Utilities' PowerStream RZ billing system is used again three months after the claim has been submitted to the IESO to determine the actual kWh consumed by and billed to RPP customers (there is a time lag between consumption and billing which is dependent upon a customer's meter read cycle and billing frequency). The final true-up based on actual billed consumption and actual cost of commodity and GA occurs three months after the original claim is filed as identified in Table 93, below.

Table 93 – Timing of RPP vs. Market Claim True-up – PowerStream RZ

Period Covered	Original Claim	"Actual" Claim True-up
April	April	July

The actual billed kWh consumption and corresponding dollar values (revenues and costs) are available from PowerStream RZ's billing system. These are allocated to the target month based on the customer's bills that contain consumption for that month based on the meter read date range. It is assumed that consumption occurs evenly over the billing period (same kWh usage and dollar per day). Although kWh consumption by hour is available from smart meters it is not available in the billing system; or aggregated elsewhere. The calculation is performed three months subsequent to the customer's consumption to ensure that 100% of consumption for a particular month is captured (for example, after three months, 100% of consumption for November 2017 will have been billed by February 28, 2018). The actual claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

RENEWABLE GENERATION CONNECTION RATE PROTECTION

In the 2016 Custom IR Rate Application (EB-2015-0003), the Board approved PowerStream's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed DSP, to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2016 to 2020.

The amounts for 2016 and 2017, identified in Table 94 below, were approved in total by the Board in its Decision and Order in respect of the 2017 Green Energy Plan Electricity Rate Protection Benefit and Charge Effective January 1, 2017 (EB-2017-0004), dated February 3, 2017 and its Decision and Order in respect of 2016 Green Energy Plan Electricity Rate Protection Benefit and Charge (EB-2016-0012), dated January 28, 2016. Due to the timing of the 2016 decision, the approved 2015 amount was continued for 2016 and the shortfall was added to the approved amount for 2017. The amount for 2018 was approved by the Board in its Decision and Order in Alectra Utilities' 2018 EDR Application (EB-2017-0024).

Alectra Utilities is requesting to collect renewable generation funding of $260,517 in 2019 or $21,710 per month from all provincial ratepayers for the PowerStream RZ, as identified in Table 94, below.

Table 94: Green Energy Plan Rate Protection Benefit and Charge in 2019 – PowerStream RZ

	Board Approved RR Basis			Proposed for Recoveries - TEST YEARS				
	2013 (EB-2012-0161)	2014 (EB-2013-0166)	2015 (EB-2014-0608)	2016	2017	2018	2019	2020
2011 & Prior RGC Investmentt	$162,684	$67,769	$53,805					
2012 RGC Investment		$146,070	$61,132					
2013 RGC Investment			$146,353					
2014 RGC Investment				**$150,269**(1)				
2015 RGC Investment				**$4,208** (2)				
2010-2020 RGC Investment				**$272,792**	**$271,060**	**$266,079**	**$260,517**	**$256,894**
	$162,684	$213,839	$261,290	**$427,270**	**$271,060**	**$266,079**	**$260,517**	**$256,894**
	NOTES:							
(1)	Revenue Requirement for 2014 and 2015							
(2)	Revenue Requirement for 2015							

DISPOSITION OF LRAM VARIANCE ACCOUNT

Alectra Utilities is applying for disposition of the balance in the LRAMVA account resulting from its CDM activities in 2016 in the PowerStream RZ. The total amount requested for disposition is a debit of $2,535,878 including forecasted carrying charges of $89,513 through to December 31, 2018. Actual savings from CDM activities for 2016 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities most recent application for the recovery of lost revenues due to CDM activities for the PowerStream RZ was filed in Alectra Utilities 2018 EDR Application (EB-2017-0024). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2014 and 2015 in the PowerStream RZ.

Lost Revenue Adjustment Mechanism for 2011-2014 and 2015-2020

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive to the OEB (the "Directive") to establish electricity and conservation and demand management targets to be met by licensed electricity distributors over a four year period commencing January 1, 2011. The Minister of Energy and Infrastructure included guidance to the OEB that lost revenues that result from CDM programs should not act as a disincentive to a distributor to promote CDM activities.

On April 26, 2012, in response to the Directive, the OEB issued a new set of *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets that are a condition of licence. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period.

The OEB authorized the establishment of an LRAM variance account (“LRAMVA”) to record, at the customer rate-class level, the difference between:

(i) the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for CDM programs, and

(ii) the level of CDM program activities included in the distributor’s load forecast (i.e. the level embedded into rates).

The variance calculated from the comparison will result in a credit or a debit to the ratepayer at the customer class level in the LRAMVA.

On March 31, 2014, the Ministry of Energy and Infrastructure, in response to the Government of Ontario’s Long-Term Energy Plan (“LTEP”), issued a directive to the OEB (“the Conservation Directive”) to promote CDM, including amending the licences of electricity distributors and establishing CDM Requirement guidelines (“the 2015 CDM Guidelines”).

On December 19, 2014, the OEB issued *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* (EB-2014-0278) (“2015 CDM Guidelines”) which amended the electricity distribution licences of all electricity distributors to include a condition that requires the distributors to make CDM programs available to each customer segment in their service area and to report annual CDM results to the IESO. The Board also requires that electricity distributors work with natural gas distributors and the IESO in coordinating and integrating electricity conservation and natural gas demand side management programs. The 2015 CDM Guidelines also confirmed the continuation of the LRAM mechanism to compensate distributors for lost revenues resulting from CDM programs for the 2015 to 2020 period.

On May 19, 2016, the OEB issued an *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs,* on the calculation of the LRAMVA in respect of peak demand savings. In this report, the OEB determined that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year. The OEB also indicated that peak demand savings from Demand Response ("DR") programs should generally not be included within the LRAMVA calculation.

LRAM Calculations

The OEB has identified that distributors can apply for disposition of the balance in the LRAMVA as part of their cost of service applications and may apply for disposition on an annual basis, as part of their IRM application, if the balance is deemed significant by the applicant. Alectra Utilities is requesting approval for recovery of lost revenues of $2,535,878, including carrying charges, which is above PowerStream RZ's materiality threshold. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $997,500.

Alectra Utilities has determined the LRAM amount in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines and its 2016 Updated Policy for the calculation of LRAMVA in respect of peak demand savings. Alectra Utilities has completed the 2018 LRAMVA work form for the PowerStream RZ, provided by the OEB, to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA work form is filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017, and is provided in Attachment 27. Alectra Utilities has not included peak demand (kW) savings from Demand Response programs in its lost revenue calculation for the PowerStream RZ, in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities provides the following information for the PowerStream RZ:

(i) Alectra Utilities has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount for the PowerStream RZ; and

(ii) Alectra Utilities has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of the PowerStream RZ lost revenue calculation. The IESO's Final Annual Verified Results for 2016 are filed as Attachment 28.

(iii) The IESO reports results by program. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Alectra Utilities estimated the split by rate class, drawing on participant-specific information where available; and

(iv) Alectra Utilities has provided additional data in Tab 8. Street Lighting of the LRAMVA Model in support of streetlight project savings. Demand savings for the retrofit streetlight project do not appear on the IESO's Final Verified Result Report, as the reduction to peak demand occurs outside the IESO's peak hours. As LED streetlights are installed, reports are received from the municipalities with the details of the existing street lights and load that have been removed and the replacement LED streetlights installed and their load ("LED Reports"). Alectra Utilities has used the reduction in billed kW demand from the LED Reports for purposes of calculating the LRAMVA adjustment in respect of the streetlight LED projects.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2017. Alectra Utilities proposes to dispose of its 2017 LRAMVA balance for the PowerStream RZ in a future rate proceeding. Alectra Utilities identifies that the balance in Account 1568, LRAM Variance Account, as identified in Tab "3. Continuity Schedule" for the PowerStream RZ does not match the amount being requested for disposition due to the exclusion of the 2017 balances as mentioned, previously.

Alectra Utilities is seeking recovery of lost revenues, for the PowerStream RZ, for the period January 1, 2016 to December 31, 2016 resulting from the following:

(i) 2011 to 2015 CDM persistence savings in 2016; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2016.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab “3. Distribution Rates” of the LRAMVA work form and in Table 95 identified below.

Table 95 – Distribution Volumetric Rates – PowerStream RZ

Year	Residential	GS<50 kW	GS>50 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
	kWh	kWh	kW	kWh		kW	kW
2016	$0.0141	$0.0142	$3.3892	$1.4413	$0.0162	$8.1591	$6.7526

Alectra Utilities’ PowerStream RZ’s LRAMVA threshold, approved in the PowerStream 2013 Cost of Service Application (EB-2012-0161) is used as the comparator against actual savings for the lost revenue calculation for 2016. PowerStream’s LRAMVA threshold is provided in Tab “2. LRAMVA Threshold” of the LRAMVA work form and in Table 96, below.

Table 96 – LRAMVA Thresholds – PowerStream RZ

Year	LRAMVA Threshold	Residential	GS<50 KW	GS>50 KW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
		kWh	kWh	kW	kW	kWh	kW	kW
2011								
2012								
2013	2013	44,207,932	16,984,563	195,431	3,732	208,627	20	2,868
2014	2013	44,207,932	16,984,563	195,431	3,732	208,627	20	2,868
2015	2013	44,207,932	16,984,563	195,431	3,732	208,627	20	2,868
2016	2013	44,207,932	16,984,563	195,431	3,732	208,627	20	2,868

Alectra Utilities has calculated carrying charges for the PowerStream RZ on the LRAM amounts from January 1, 2016 to December 31, 2018 in the LRAMVA work form using the OEB’s annual prescribed interest rates as provided in Tab “6. Carrying Charges” of the LRAMVA work form. The total amount requested for disposition is a recovery of $2,535,878 representing a principal balance of $2,446,365 and carrying charges of $89,513.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class for the PowerStream RZ, in Tables 97 and 98 below, which is also provided in Tab “1. LRAMVA Summary” of the LRAMVA work form.

Table 97 – LRAMVA Totals by Rate Class – PowerStream RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$642,055	$22,451	$664,506
GS<50 KW	kWh	$629,269	$22,003	$651,272
GS>50 KW	kW	$1,017,231	$35,569	$1,052,800
Large Use	kW	($5,379)	($188)	($5,567)
Unmetered Scattered Load	kWh	($3,380)	($118)	($3,498)
Sentinel Lighting	kW	($164)	($6)	($170)
Street Lighting	kW	$166,732	$9,802	$176,534
Total		**$2,446,365**	**$89,513**	**$2,535,878**

Table 98 – LRAMVA by Year and Rate Class – PowerStream RZ

Description	Residential	GS<50 kW	GS>50 KW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	kWh	kWh	kW	kW	kWh	kW	kW	
2016 Actuals	$1,265,387	$870,450	$1,679,587	$0	$0	$0	$186,097	$4,001,521
2016 Forecast	($623,332)	($241,181)	($662,356)	($5,379)	($3,380)	($164)	($19,365)	($1,555,156)
2016 LRAM Balance	**$642,055**	**$629,269**	**$1,017,231**	**($5,379)**	**($3,380)**	**($164)**	**$166,732**	**$2,446,365**
Carrying Charges	**$22,451**	**$22,003**	**$35,569**	**($188)**	**($118)**	**($6)**	**$9,802**	**$89,513**
Total LRAMVA Balance	**$664,506**	**$651,272**	**$1,052,800**	**($5,567)**	**($3,498)**	**($170)**	**$176,534**	**$2,535,878**

The proposed rate riders that result from the disposition of Account 1568, LRAM Variance Account, is identified in Table 99 below and included in Tab “8. Calculation of Def-Var RR” in the IRM Model.

Table 99 – LRAMVA Rate Riders – PowerStream RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential Service Classification	$0.00	$0.0003	kWh
General Service Less Than 50 kW Service Classification	$0.00	$0.0006	kWh
General Service 50 To 4,999 kW Service Classification	$0.00	$0.0886	kW
Large Use Service Classification	$0.00	($0.0705)	kW
Unmetered Scattered Load Service Classification	$0.00	($0.0003)	kWh
Standby Power Service Classification	$0.00	$0.0000	kW
Sentinel Lighting Service Classification	$0.00	($0.2176)	kW
Street Lighting Service Classification	$0.00	$1.2612	kW

TAX CHANGES

The OEB policy, as described in the Board'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 their OEB approved base rates. If applicable, these amounts will be refunded to customers over a 12-month period.

In this application, Alectra Utilities is not applying for a rate rider associated with the 50/50 sharing of the legislated tax change impact as Alectra Utilities' corporate tax rate of 26.50% is not expected to change in 2019. Therefore, there is no shared tax savings in this application.

INCREMENTAL CAPITAL MODULE

Overview

PowerStream filed a five year DSP ("PowerStream DSP") for 2016 to 2020 in its Custom Incentive Rate Application (EB-2015-0003). In the PowerStream DSP, it explained the processes, drivers, outcomes and justifications for the proposed capital investments required for PowerStream to achieve its capital planning objectives. The PowerStream DSP incorporated PowerStream's integrated approach to planning, prioritizing and managing assets and consolidated the asset management processes that informed the capital investment plan. The PowerStream DSP also included activities such as regional planning, local stakeholder engagement, considerations for renewable generation connections and smart grid developments. The OEB issued its decision for the PowerStream Custom IR Application on August 4, 2016, within which it approved a capital budget of $115.8MM in 2017. This represented a 12% reduction to PowerStream's capital budget, as compared to the $131.6MM proposed in the PowerStream DSP.

Alectra Utilities requested incremental capital funding for the PowerStream RZ in its 2018 EDR Application. In the EDR Application Decision, the OEB approved incremental funding for the York Region Rapid Transit project.

Alectra Utilities is seeking OEB approval for incremental capital funding for the PowerStream RZ for 2019, through distribution rate riders as identified in Attachment 29. Alectra Utilities has capital investment needs for the PowerStream RZ that are not funded through existing distribution rates. The needs fall into the following categories: system access and system service. As previously stated, the PowerStream RZ is on Price Cap IR for the purpose of setting 2019 electricity distribution rates and, therefore, the ICM is available to the PowerStream RZ and is incorporated as the relief sought in this application. The projects that form the ICM request for the PowerStream RZ reflect significant, incremental, and discrete projects, as contemplated by the EDR Application Decision.

The PowerStream DSP was designed to address capital expenditures across the four prescribed OEB categories: system access, system service, system renewal, and general plant. It provides justification regarding capital investments required for new connections, system capacity, system reliability, new technologies, renewal of sub-standard assets and general plant capital investments. The PowerStream DSP includes investments necessary to (i) ensure connection and system capacity are available to meet growth, and (ii) address and renew sub-standard assets to facilitate operational effectiveness and system reliability.

Alectra Utilities' asset management planning process in the PowerStream RZ, identified in the PowerStream DSP, incorporates the key elements of asset knowledge, asset strategy and planning, asset management as well as decision-making and outputs. Capital projects are prioritized to realize the optimal value of projects and programs over the planning period across all four investment categories.

Alectra Utilties has a robust capital planning process in the PowerStream RZ that utilizes sophisticated software and a multi-disciplinary review to determine the relative value and risks associated with a portfolio of projects. Business cases are prepared for all capital investments in advance of the optimization process to ensure consideration for capital requests. PowerStream further leverages appropriate capital investment oversight of the capital portfolio with a consistent approach to reviewing the status of expenditures, controlling the additions and removals of projects and management of expenditures approvals of project execution.

The output of the asset management and decision making activities of the asset management process is an optimized capital investment portfolio of selected project and programs. The portfolio of selected capital projects and programs are as a result of the capital planning process which consists of business case development and portfolio optimization. Capital investments have been summarized according to the Board's investment categories, which include investment requirements for System Access, System Renewal, System Service, and General Plant.

Alectra Utilities needs to increase investment in the PowerStream RZ for system access and service projects; a theme articulated in its last rebasing application (EB-2015-0003).

As a result of increased economic development and demand for new housing in York Region and Simcoe County, Alectra Utilities is adding over 5,800 new customers annually to its existing customer base in the PowerStream RZ. This growth in customers and load puts increasing pressure on the distribution system, which requires extending power lines, upgrading capacity to existing power lines, and adding new capacity to load constrained areas. In addition, regions are embarking on significant public transportation infrastructure projects.

There is increasing volume and scope of road widening and transportation infrastructure projects; as a result, Alectra Utilities must relocate the existing infrastructure in the PowerStream RZ. These investments are mandated under regulations and are non-discretionary.

Supporting new connections, as a result of Residential and Industrial, Commercial and Institutional growth, requires the expansion of distribution system capacity in order to deliver supply to the new service areas. This is accomplished through the addition of additional transformer stations, municipal stations, and new overhead lines and underground cables.

Alectra Utilities provides a summary of its historical and proposed capital investments by category in Table 100 below. Amounts shown are net of contributed capital .The proposed capital investments ensure that Alectra Utilities is able to distribute electricity in the PowerStream RZ in a safe and reliable manner, meet system load growth demands, and complete all regulatory driven initiatives. Each investment category is further discussed below. Alectra Utilities has filed at Attachment 33, details by project for the proposed 2019 capital spending plan.

Table 100 – Capital Expenditures by Category from 2014 to 2022 ($000s) – PowerStream RZ

Category	Actual 2014	Actual 2015	Actual 2016	COS 2017	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
System Access	$26,229	$25,620	$22,790	$32,024	$36,691	$43,037	$38,529	$30,156	$33,771	$25,492
System Renewal	$39,186	$46,997	$42,004	$41,848	$38,399	$31,923	$38,003	$43,041	$41,687	$41,936
System Service	$17,946	$23,542	$27,529	$30,986	$30,861	$11,469	$17,044	$18,683	$20,698	$42,834
General Plant	$26,148	$22,092	$8,839	$10,927	$6,370	$6,618	$8,498	$9,923	$10,983	$8,668
Total	**$109,509**	**$118,251**	**$101,162**	**$115,784**	**$112,321**	**$93,046**	**$102,074**	**$101,802**	**$107,138**	**$118,930**

Alectra Utilities provides an explanation of capital expenditures for the PowerStream RZ from 2014 to 2022 by system category below. Alectra Utilities has filed at Attachment 33, details by project for the proposed 2018 capital spending plan.

System Access

System Access investments are projects outside of Alectra Utilities' control, that are required to meet customer service obligations in accordance with the DSC. These projects include connecting new customers; metering; building new subdivisions; and relocating system plant for roadway reconstruction work. Alectra Utilities uses an economic evaluation methodology prescribed in the DSC for the PowerStream RZ, to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget.

These investments are typically a high priority, cannot be deferred and must proceed as planned. System Access actual and forecast capital expenditures by from 2014 to 2020 are provided in Table 101, below.

Table 101 – System Access Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2014	Actual 2015	Actual 2016	COS 2017	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
New Connections and Subdivisions	$8,759	$14,291	$13,761	$15,644	$14,350	$16,180	$16,596	$17,274	$17,849	$18,420
Other Customer Initiated Work	$1,085	$355	-$270	$404	-$703	$455	$446	$468	$491	$516
RGEN New Connections	$30	$105	$166	$0	$127	$55	$0	$0	$0	$0
Road Authority	$13,950	$7,422	$7,301	$13,070	$20,903	$23,516	$17,047	$5,700	$5,095	$5,175
System Access Other Misc	$0	$1	$41	$0	$0	$0	$0	$0	$0	$0
Metering	$2,406	$3,446	$1,791	$2,905	$2,014	$2,831	$4,440	$6,714	$10,335	$1,381
System Access	**$26,229**	**$25,620**	**$22,790**	**$32,024**	**$36,691**	**$43,037**	**$38,529**	**$30,156**	**$33,771**	**$25,492**

Alectra Utilities continues to experience rapid growth driven by developments for the PowerStream RZ in York Region and parts of Simcoe County. As communities within the PowerStream RZ continue to grow, road construction, re-alignment and widening of existing roads as well as the installation of new water and sewer infrastructure occur. This development work is controlled by Provincial, Regional and Municipal authorities. The distribution system is located on the road allowance; at the request of the road authority, sections of the distribution system must be relocated to accommodate this development work. In addition, the building of new subdivisions and consequently requests for customer connections are projected to increase.

York Region Rapid Transit ("YRRT")

The primary component of road authority investments in the system access category is the investment necessary to support the development of the York Region Rapid Transit ("YRRT") system. Due to rapid growth, roads in York Region are becoming increasingly congested; the YRRT system will reduce traffic congestion through the development of a rapid transit network including bus rapid transit ("BRT") and subway extensions. This network will facilitate travel in and around York Region and connect to other transit systems across the Greater Toronto and Hamilton Area ("GTHA"); and requires Alectra Utilities to relocate electrical distribution assets.

Alectra Utilities received OEB-approval for the 2018 YRRT ICM project. The relocation efforts for the Yonge Street Rapid Transit Corridor Phase 2 (“Y2”) and Highway 7 Rapid Transit Corridor Phase 2 (“H2”) began in 2016 and conclude in 2019. Alectra Utilities is seeking ICM funding for the last phase in this project for Y2 and H2.

System Renewal

System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets.

Table 102 – System Renewal Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2014	Actual 2015	Actual 2016	COS 2017	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
UG Lines - Planned Asset Replacement	$23,829	$22,467	$17,893	$16,714	$15,214	$13,116	$13,176	$16,468	$16,349	$17,362
Overhead Lines - Planned Asset Replacement	$5,354	$7,489	$7,733	$7,456	$6,814	$6,036	$7,684	$6,072	$6,559	$7,485
Distribution Lines - Emergency/Reactive	$8,700	$11,233	$8,416	$9,291	$9,364	$8,965	$9,106	$9,183	$9,275	$9,494
Stations Replacement Project	$1,244	$0	$0	$0	$0	$0	$0	$0	$0	$0
Stations/P&C - Planned and Emergency	$0	$2,044	$3,655	$2,587	$2,388	$2,583	$3,998	$5,742	$4,178	$2,145
Storm Hardening & Rear Lot Conversion	$60	$3,276	$4,308	$5,800	$4,620	$1,057	$4,039	$5,361	$5,326	$5,450
System Renewal Other Misc	$0	$489	$0	$0	$0	$166	$0	$214	$0	$0
System Renewal	**$39,186**	**$46,997**	**$42,004**	**$41,848**	**$38,399**	**$31,923**	**$38,003**	**$43,041**	**$41,687**	**$41,936**

System renewal investments in the PowerStream RZ are largely driven by: the renewal of assets in sub-standard condition and at end of life; emergency replacement; and initiatives related to storm-hardening. Asset renewal includes underground cable replacement, pole replacement, rear lot conversions and mini-rupter switch replacement.

System Service

Projects in this category are driven by Alectra Utilities' expectations that the evolving use of the system may create system capacity constraints or adversely impact system reliability. These investments are required to support the expansion, operation and reliability of the distribution system.

Table 103 – System Service Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2014	Actual 2015	Actual 2016	COS 2017	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Additional Capacity - Lines	$3,832	$7,159	$10,794	$16,690	$17,238	$5,637	$8,849	$6,454	$4,573	$8,743
Additional Capacity - Stations	$5,752	$9,180	$13,234	$8,850	$9,031	$1,268	$2,598	$4,300	$10,215	$26,928
Reliability including Distribution Automatio	$3,617	$4,250	$3,216	$4,070	$3,718	$3,089	$4,010	$5,820	$4,302	$5,513
Smart Grid/RGEN - System Related	$0	$0	$0	$1,070	$419	$1,070	$1,070	$1,070	$1,070	$1,070
Station Safety & Security	$80	$116	$22	$223	$361	$405	$423	$989	$537	$508
System Service Other Misc	$4,667	$2,836	$262	$83	$94	$0	$94	$49	$0	$72
System Service	**$17,946**	**$23,542**	**$27,529**	**$30,986**	**$30,861**	**$11,469**	**$17,044**	**$18,683**	**$20,698**	**$42,834**

General Plant

General plant projects include investments in tools, vehicles, building and information systems technology equipment that are required to support the operation and maintenance of the distribution system.

Table 104 – General Plant Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2014	Actual 2015	Actual 2016	COS 2017	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Buildings and Emerging Operations	$2,304	$4,227	$473	$965	$1,719	$109	$1,867	$2,715	$3,056	$2,141
Customer Information Systems	$15,577	$11,264	$3,137	$1,498	$0	$0	$0	$0	$0	$0
Fleet	$812	$1,715	$1,779	$1,510	$1,178	$2,522	$2,166	$2,479	$2,530	$2,394
General Plant Other Misc	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest Capitalization	$1,451	$922	$691	$1,040	$1,444	$1,219	$1,232	$1,226	$1,293	$1,227
IT and Info/Communication Systems	$5,068	$3,531	$2,315	$3,896	$1,666	$2,301	$2,777	$3,037	$3,634	$2,433
Smart Grid - Other	$0	$0	$0	$1,337	$0	$0	$0	$0	$0	$0
Tools	$937	$432	$444	$679	$362	$465	$456	$466	$470	$473
General Plant	**$26,148**	**$22,092**	**$8,839**	**$10,927**	**$6,370**	**$6,618**	**$8,498**	**$9,923**	**$10,983**	**$8,668**

Alectra Utilities reviewed and optimized its long-term general plant investment needs for the Power Stream RZ subsequent to the amalgamation of Horizon Utilities Corporation, Enersource Hydro Mississauga Inc. and Hydro One Brampton Networks Inc. Investments related to merger transitional costs have been excluded from the general plant expenditures in Table 104 above. Only capital expenditures related to on-going business requirements for Alectra Utilities are included. Following the merger, General Plant investment needs are being optimized for the entire organization and are not budgeted by rate zone. For the purpose of the ICM capital expenditure tables, General Plant investments have been allocated to the Enersource and PowerStream rate zones based on an allocation methodology using 2016 rate base by rate zone, filed as part of the 2016 ROE RRR filing for each of the predecessor utilities.

Customer Consultation

As discussed previously, Alectra Utilities engaged Innovative to solicit feedback from customers on proposed incremental capital projects for the PowerStream RZ. This builds on the customer engagement completed by Innovative as part of the 2018 EDR Application. The Innovative Report is provided as Attachment 34.

As set out there, a telephone survey was conducted using stratified random samples for Residential and General Service Customers and an online survey was also deployed for Large Use Customer. This approach allowed Alectra Utilities to capture customers' views on the emerging needs or shifting priorities and to generate feedback on the specific projects being considered for this application.

The top two priorities for Alectra Utilities' customers in both the Enersource and PowerStream rate zones are: delivering reasonable distribution rates; and ensuring reliable electrical service. The engagement confirms that the vast majority of customers are satisfied with the current level of reliability they experience. In principle, most customers support some form of investment program that ensures a consistently reliable and modern distribution system, which also addresses growth and system demands. Customers also expressed frustration in relation to their electricity bills; Alectra Utilities is well aware of this customer sentiment. When asked how Alectra Utilities can improve service, most common responses throughout the engagement were either "nothing" or "lower rates".

In the PowerStream RZ, the one proposed ICM where there was a difference in customer outcomes, most customer groups preferred the approach of moving the existing mix of overhead and underground wires rather than moving to a fully underground system. A majority of respondents further indicated that the overall proposed 2019 ICM rate increase was reasonable, given the benefits.

In conducting customer engagement, Alectra Utilities determined the maximum eligible capital it could apply for in the PowerStream RZ, based on its most recent 2019 capital forecast of $102,074,174, and its materiality threshold of $76,564,006. The computation of the materiality threshold is discussed in further detail below. The difference between the 2019 capital forecast, before incorporating customer preferences, and the materiality threshold was $25,510,168 as identified in Table 105, below.

Table 105 – Eligible Incremental Capital for Customer Consultation – PowerStream RZ

Eligible Incremental Capital	Capital Expenditures
2019 Capital Forecast	$102,074,174
Less: Materiality Threshold	$76,564,006
Maximum Eligible Incremental Capital	**$25,510,168**

Alectra Utilities identified three discrete and material capital projects for the PowerStream RZ for presentation to customers which totalled approximately $20.9MM. These projects are identified in Table 106 below and do not include projects related to General Plant, for which Alectra Utilities is not seeking incremental capital funding.

Table 106 – Eligible Capital Projects for Customer Consultation – PowerStream RZ

Project Description	Capital Expenditures
Road Authority YRRT Yonge St	$13,272,246
Bathurst Ave from Hwy 7 to Teston Road	$5,500,000
System Access	**$18,772,246**
Barrie TS Upgrade- Metering and Feeder Relocation	$2,100,000
System Service	**$2,100,000**
Total PowerStream Rate Zone Incremental Capital Funding	**$20,872,246**

As identified in the Innovative Report filed as Attachment 34, customers were presented with the 2019 bill impacts related to the implementation of the projects listed in Table 106 above. They were also presented with the total bill impact over the deferred rebasing period. These are identified in Table 107, below. The calculation of the rate riders associated with the proposed ICM is provided in Attachment 29. Large Use customers were presented with individual bill impacts based on historical usage.

Table 107 – Bill Impacts for Incremental Capital Presented to Customers – PowerStream RZ

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	GS<50 (2000 kWh)	GS>50
System Access	$18.8	$0.19	$0.39	$9.01
System Service	$2.1	$0.02	$0.04	$1.02
Total	**$20.9**	**$0.21**	**$0.43**	**$10.03**

The ICM questions varied according to the specific projects being considered in each rate zone. In the PowerStream RZ, for projects with design options that delivered different potential outcomes to customers, customers were asked to provide their preference between the options. Customers were also asked about the total bill impact of these projects over the deferred rebasing period.

Customers in the PowerStream RZ were asked to consider the three ICM projects identified in Table 106, above. The York Regional Rapid Transit project is a system access project with no major design choices. The Barrie TS project has two options with no differences in customer outcomes, so Alectra Utilities is proposing the least expensive option. Those two projects were described to customers, but no project specific questions were asked. Customers were then asked about the design choices for Bathurst Street road widening project. The options for this ICM project tied costs to potential benefits.

For the Bathurst Road widening, business customers (small business, mid-market and large use) preferred staying with the current mix of overhead and underground wires rather than replacing with an entirely underground system. However, residential customers are divided, with 46% preferring the current mix to 45% preferring the all underground system option at a higher rate impact.

Table 108 summarizes customer preferences between the options for the Bathurst Road widening project.

Table 108 – ICM Project Feedback PowerStream RZ

Bathurst Road Widening	Residential	Small Business	Mid-Market	Large Use
Move Current Mix - ***Move the current mix of overhead and undergound wires and equipment at a cost of $5.5MM***	46%	48%	62%	6 of 13
Replace with Underground System - ***Replace the overhead system with an underground system at a cost of between $25MM and $35MM***	45%	40%	31%	2 of 13
Don't know	8%	12%	8%	5 of 13

Further, for all customer groups in the PowerStream RZ, a majority of the respondents indicate that the proposed rate increase for 2019 is reasonable.

Table 109 summarizes customer feedback on the reasonability of the proposed rate increase.

Table 109 – Customers' view on ICM Bill Impacts PowerStream RZ

Opinion of Proposed Plan	Residential	Small Business	Mid-Market	Large Use
The proposed rate increase is reasonable	63%	66%	59%	8 of 13
The proposed rate increase is unreasonable	33%	23%	34%	2 of 13
Don't know	4%	8%	6%	3 of 13

Based on feedback from customers, as provided in the Innovative Report, Alectra Utilities maintained its list of proposed ICM projects in the PowerStream RZ; and its ICM request of $20.9MM in capital expenditures.

Alectra Utilities provides the eligibility criteria for its capital funding request, below.

Eligibility for Incremental Capital

In order to be eligible for incremental capital, 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 Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219), issued on September ("the ACM Report").

These criteria are discussed in detail, below.

The OEB's Capital Module for ACM and ICM ("ACM Report") for the PowerStream RZ is attached as Attachment 29.

<u>Materiality</u>

Materiality Threshold Test

The Board states in the ACM Report that "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-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"

The Board-defined materiality threshold is represented by the following formula:

$$\textit{Threshold Value}\,(\%) = 1 + [(\frac{RB}{d}) \times (g + PCI \times (1 + g))]] \times ((1 + g) \times (1+ PCI)^{n-} + 10\%$$

RB = rate base from the distributor's last cost of service

d = depreciation from the distributor's last cost of service

g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application

PCI = Price Cap Index (IPI-stretch_factor) from the distributor's most recent Price Cap IR application as a placeholder for the initial application filing to be updated when new information becomes available

n = number of years since the last rebasing

The materiality threshold has been calculated for the PowerStream RZ using the Board-approved rate base and depreciation amounts from its 2017 Cost of Service Application (EB-2015-0003), a price cap index (PCI) of 0.9% and a growth rate of 0.82%.

The PCI of 0.9% is a placeholder to be updated with the OEB's approved PCI for 2019 when it is available. It is based on inflation of 1.2% less a productivity factor of 0% and a stretch factor of 0.3% as identified in Table 110 below.

The growth rate of 0.82% has been calculated in accordance with the ACM Report and is equal to the increase in revenue based on PowerStream's 2017 OEB approved billing determinants divided by PowerStream's 2016 actual billing determinants, using 2017 approved rates. The growth rate calculation is identified in Table110 below.

Table 110 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula approved in the ACM Report. The threshold value for 2019 is 146% which results in a threshold capital expenditure value of $76,564,006.

Table 110 – Threshold Capital Expenditure Calculation – PowerStream RZ

Description	Amount
Inflation	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	0.90%
2017 Volumes @ 2017 Rates	$201,816,357
2016 Volumes @ 2017 Rates	$200,168,360
Growth Factor	0.82%
Year	2,019
# Years since rebasing	2
Price Cap Index	0.90%
Growth Factor	0.82%
Dead Band	10%
Rate Base	$1,082,805,165
Depreciation	$52,272,173
Threshold Value % - 2019	146%
Threshold Capital Expenditure $ - 2019	**$76,564,006**

Eligible Capital Amount

Table 111 below compares the 2019 capital forecast for the PowerStream RZ to the Threshold Capital Expenditure to calculate the maximum eligible incremental capital of $25,510,168 for the PowerStream RZ.

Table 111 – Maximum Eligible Incremental Capital – PowerStream RZ

Eligible Incremental Capital	Capital Expenditures
2019 Capital Forecast	$102,074,174
Less: Materiality Threshold	$76,564,006
Maximum Eligible Incremental Capital	**$25,510,168**

Table 112 below identifies the eligible capital projects for which the PowerStream RZ is seeking approval, after the adjustment for customer preferences, discussed above. Only projects that are discrete and material have been included. These projects are discussed in detail in Attachment 31. The Road Authority YRRT and Bathurst Ave. System Access projects are presented net of customer contributions of $14.6MM and $2.0MM, respectively, as identified in the business cases, filed as Attachment 31. There is no customer contribution for the Barrie TS Upgrade.

Table 112 – 2019 Eligible Capital Projects by Category – PowerStream RZ

Project Description	Capital Expenditures
Road Authority YRRT Yonge St	$13,272,246
Bathurst Ave from Hwy 7 to Teston Road	$5,500,000
System Access	**$18,772,246**
Barrie TS Upgrade- Metering and Feeder Relocation	$2,100,000
System Service	**$2,100,000**
Total PowerStream Rate Zone Incremental Capital Funding	**$20,872,246**

<u>Need</u>

Means Test

In addition to the materiality criteria, a distributor must pass the Means Test (as defined in the ACM Report) in order to qualify for funding through an ICM in an Incentive Rate Setting term.

If a distributor's regulated return, as calculated in its most recent calculation (Reporting and Record Keeping Requirements ("RRR") 2.1.5.6), exceeds 300 basis points above the deemed return on equity ("ROE") embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.

Alectra Utilities filed its first annual Reporting and Record Keeping Requirements ("RRRs") post consolidation on April 30, 2018. RRR data for all measures were filed for Alectra Utilities, and not individually, by rate zone. Alectra Utilities 2017 ROE was calculated to be 8.43%, 47 basis points below a calculated ROE for Alectra of 8.90%. Alectra Utilities calculated a consolidated deemed ROE percentage, using the weighted average of the OEB-approved rate base amounts for each rate zone, from the most recent OEB-approved rebasing application for each of the predecessor companies. Therefore Alectra Utilities meets the Means Test. Alectra Utilities ROE calculation for 2017, filed in RRR 2.1.5.6, is filed as Attachment 30.

Discrete and Material Projects

As identified on page 17 of the ACM report, amounts must be based on discrete projects, and should be directly related to the claimed driver.

Each eligible capital project is a discrete project that meets or exceeds the materiality level for the PowerStream RZ. The projects are also significant relative to Alectra Utilities' overall capital expenditures and are not funded through existing rates. Each project is distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning process as required in 2019. Alectra Utilities overall 2019 capital budget for all rate zones is $257.3MM.

Further information with respect to the driver of each project is provided in each business case in Attachment 31.

<u>Prudence</u>

The eligible capital projects for which the PowerStream RZ is requesting approval represent the most cost effective option for ratepayers. Analysis of options is provided in the business case for each eligible capital project in Attachment 31.

A description of each of the projects' need and prudence can be found in the business case summaries set out immediately below. The project-related business cases can be found at Attachment 31.

<table>
<tr><th>Project/ Budget/ In Service Date (“ISD”)</th><th>Project Need and Description</th></tr>
<tr><td>York Region Rapid Transit (YRRT) VIVA Bus Rapid Transit (BRT) Y2 and H2 Projects

(see System Access Project Business Case 101762-1)

Budget:

$11.24MM (2018), $13.27MM (2019)

Forecast ISD:

2018 Phase - Q4/2018

2019 Phase – Q4/2019</td><td><u>York Region Rapid Transit (YRRT) VIVA Bus Rapid Transit (BRT) Y2 and H2 Projects</u>

<u>System Access: $13.27MM</u>

<u>Project Description and Drivers</u>

• Since 2010, PowerStream (now Alectra Utilities) has been relocating overhead and underground distribution assets in its service area as required to accommodate the York Region Rapid Transit Corporation’s (“YRRTC”) Bus Rapid Transit (“BRT”) developments. The timelines for these transit infrastructure works are driven by the YRRTC, in conjunction with its contractors.
• York Region’s existing road network consists of more than 4,100 lane kilometers of urban and rural roads that enable more than six billion vehicle kilometers travelled annually. In order to meet the transportation needs resulting from projected growth (including 630,000 additional population by 2041), York Region revised its original 2009 Transportation Master Plan (“TMP”) in 2016. The updated TMP outlines, among other things, the expansion and development of certain BRT rapidways.
• The rapidway development phases that are currently under construction and impacting the PowerStream RZ include the “Y2 phase” (two project sections along Yonge totalling 6.5km), and the “H2 phase” (two project sections along Highway 7 and several other roadways totalling 8.5km). The H2 and Y2 phases are slated for completion in 2018 and 2019, respectively, and involve major thoroughfares with significant overhead and underground distribution plant (including 27.6kV feeders) which must be relocated before the rapidways can be built. H2 is to be completed in 2018 and Y2 is to be completed in 2019.

<u>Project Options</u>

• This project involves the relocation of certain overhead and underground distribution assets in the PowerStream RZ to accommodate road widening and shifting of boulevards as part of the BRT build.
• Alectra Utilities is obligated 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, this project is considered to be mandatory.</td></tr>
</table>

	• Based on the design and construction timelines provided by YRRTC and its contractors, Alectra Utilities expects to incur $11.24MM for 2018, and $13.27MM for 2019. Alectra Utilities is confident that this scope of work will be completed in 2019, based on availability of completed designs, established contractors and resources as well as demand from YRRTC to complete the work.
Barrie TS Upgrade Feeder and Wholesale Metering Relocation (see System Service Project Business Case 150259) Budget: $2.09MM Forecast ISD: Q4/2019	**<u>Barrie TS Upgrade Feeder and Wholesale Metering Relocation</u>** **<u>System Service : $2.09MM</u>** <u>Project Description and Drivers</u> • As part of regional planning led by the Independent Electricity System Operator (“IESO”) for the South Georgian Bay/Muskoka planning region, the need to renew and rebuild the Barrie Transmission Station (“TS”) was identified. The Barrie TS station renewal is required as the equipment (power transformers, 44kV switchgear, circuit breakers, disconnect switches and ancillary station equipment) have reached end-of-life. • Barrie TS was placed in-service in 1962. The 44 kV switchyard assets at Barrie TS have been identified by Hydro One as being in need of replacement in the near term. Barrie TS is currently supplied by the 230/115 kV autotransformers at Essa TS via the Essa 115 kV switchyard and 115 kV circuits E3/4B. These assets were built in the 1950s, with many of them already exceeding their expected life and in need of replacement in the near and medium term. • Barrie TS is owned and operated by Hydro One which is scheduled to undertake the station rebuild in 2019. As a result of the station rebuild, Alectra Utilities is required to relocate six feeders that service Alectra Utilities customers in City of Barrie, reconfigure the Midhurst TS feeder as well as implement corresponding wholesale revenue metering equipment required to for compliance to the IESO market rules. In addition to the feeder reconfiguration, Alectra Utilities is responsible for upgrading the revenue metering equipment at Barrie TS as per Schedule 4 of the Hydro One Customer Wholesale Revenue Metering Agreement. Alectra Utilities will install six PME’s 2 element delta metering and associated communication, protection and switching. • This work is required to be completed in 2019 in coordination with Hydro One’s rebuild of the station and other local distribution company also serviced from Barrie TS. <u>Project Options</u> • The recommended solution consists of reconfiguring the Midhurst 23M24 to

	the east side of Barrie TS for integration on Tiffin Street, relocating six feeders (13M3-13M8) to match the breaker line up for the upgraded station and utilizing Primary Metering Enclosures (PME) for wholesale metering. This option solves the access issues associated with the bus metering and is a more cost effective option. • Other options considered included: (i) relocating existing feeder 23M24 from Midhurst and the six feeders (13M3-13M8) to match the breaker line up for the upgraded Barrie TS and utilizing Bus Metering. Alectra Utilities has identified accessibility issues with the existing station bus metering at Barrie TS and determined that bus metering is more expensive solution than feeder metering; and (ii) maintaining the *status quo*. However, existing feeder integration at Barrie TS cannot be accommodated with the upgraded station because Hydro One will be moving the station egress westward which will pose a conflict with the existing circuit 23M24 circuit and will need to be relocated.
Bathurst Road Widening from Highway 7 to Teston Road (see System Access Project Business Case 150343) Budget: $5.5MM Forecast ISD: Q4/2019	**Bathurst Road Widening from Highway 7 to Teston Road** **<u>System Access: $5.5MM</u>** <u>Project Description and Drivers</u> • Alectra Utilities installs the majority of its electrical distribution infrastructure along road right of ways that are owned and managed by the City of Vaughan and the Regional Municipality of York at no cost to the utility. Alectra Utilities distribution equipment occupies road allowances, at no cost, and in return is required to remove, relocate, or reconstruct its facilities in order to accommodate the specific requirements of the road authorities. The road authorities' road works program drives plant relocation scope and timing. • Alectra Utilities remains compliant with the *Public Service Works on Highways Act* ("PSWHA") in regards to regulatory obligations and recovery of capital contributions. As per the PSWHA, Alectra Utilities recovers capital contributions related to 50% of expenditures from labour and labour saving device costs. • To expand the transportation system in order to accommodate growth in travel demand resulting from development in Richmond Hill and Vaughan, the Regional Municipality of York is widening Bathurst Street from Highway 7 to Teston Road from four to six lanes as well as including Transit-HOV lanes and off-street cycling facilities. • The length of the road widening is approximately 6km in the City of Vaughan and Town of Richmond Hill. The 2019 scope of relocation of Alectra Utilities assets includes both the overhead distribution system,

including approximately 121 poles, as well as underground distribution system assets.

Project Options

- The proposed solution is to relocate the overhead and underground assets. Road Projects are mandatory obligation under the Distribution System Code ("DSC"), Section 3.4. – Relocation of Plant that requires Alectra Utilities to address relocation of its assets when requested by a road authority.

- If this project is not approved, this mandatory work will still need to be completed to comply with the DSC and PSWHA. A reassessment of other planned discretionary projects would need to be completed to determine potential deferrals necessary.
- Other options considered include: (i) maintaining the *status quo* (which would violate the PSWHA and section 3.4 of the DSC as road projects are a mandatory obligation); (ii) the installation of underground feeder cables in the place of an overhead system would offer protection from elements such as weather related events, animal contacts and collisions from vehicles. However, the option to underground the distribution system was estimated to cost between $25MM and $35MM and was determined to be uneconomical relative to relocating the overhead system. In Alectra Utilities' Customer Engagement, Alectra Utilities' customers in the PowerStream RZ provided their preferences for the Bathurst road widening project. All three of the business groups indicated a preference to proceed with the project in the current configuration of overhead and underground system. The preference identified by residential customers was divided; 46% of the customers preferred the current mix, as compared to 45% of the customers that preferred a full underground system with higher rate impact. The Customer Engagement report is provided in Attachment 34.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $20,872,246 is $1,508,566. Table 113 below summarizes the incremental revenue requirement for the eligible projects.

Table 113 – Incremental Revenue Requirement – PowerStream RZ

Incremental Revenue Requirement	Amount
Return on Rate base - Total	$1,172,766
Amortization	$499,701
Incremental Grossed Up PILs	($163,901)
Total	**$1,508,566**

The Rate of Return has been calculated using the Board's deemed debt/equity ratios and the cost of capital parameters determined by the Board in its letter dated October 27, 2016 *"Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications"*, consistent with those approved in PowerStream's 2017 Cost of Service application (EB-2015-0003).

Project costs have been assigned to the property plant and equipment accounts as defined in the Accounting Procedures Handbook effective January 1, 2012. Amortization has been calculated on a straight-line basis over the useful life of each asset consistent with PowerStream's 2017 Cost of Service application (EB-2015-0003) and is summarized in Table 114 below.

A full year of depreciation has been included for recovery consistent with OEB policy in *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* EB-2014-0219, issued September 18, 2014.

Similarly, PILs have been calculated using a full year of Capital Cost Allowance ("CCA").

The detailed calculation of incremental revenue requirement by project is provided in the Board's Capital Module Applicable to ACM and ICM ("Capital Module") filed as Attachment 29.

Alectra Utilities also provides the calculation of the revenue requirement for each of the proposed incremental capital projects, as follows:

Table 114 – Incremental Revenue Requirement by ICM Project – PowerStream RZ

Project Description	Return on Rate base	Amortization	Incremental Grossed Up PILs	Total Revenue Requirement
Road Authority YRRT Yonge St	$746,257	$308,753	($107,351)	$947,659
Bathurst Ave from Hwy 7 to Teston Road	$309,248	$127,947	($44,486)	$392,709
System Access				**$1,340,368**
Barrie TS Upgrade- Metering and Feeder Relocation	$117,262	$63,000	($12,064)	$168,198
System Service				**$168,198**
Total Incremental Revenue Requirement				**$1,508,566**

Rate Riders

Alectra Utilities is seeking Board approval for the ICM rate riders, for the PowerStream RZ, identified in Table 115 to recover the revenue requirement of $1,508,566 identified in Table 114 above (Attachment 32). The revenue requirement has been allocated to rate classes based on the current allocation of revenue using Tab 8. Revenue Proportions of the Capital Module filed as Attachment 29. The revenue requirement for the residential class will be recovered via a fixed rate rider as per the OEB's letter issued July 16, 2015 (EB-2012-0410). Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in the Capital Module Sheets 8 and 12.

Table 115 – Incremental Capital Funding Rate Riders – PowerStream RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.20	$0.0000	kWh
General Service under 50 kW	$0.21	$0.0001	kWh
General Service 50 to 4999 kW	$1.05	$0.0314	kW
Large Use	$45.37	$0.0167	kW
Unmetered	$0.06	$0.0001	kWh
Sentinel Lights	$0.03	$0.0737	kW
Street Lighting	$0.01	$0.0472	kW

Bill Impacts - ICM Rate Riders

Table 116below identifies the bill impacts by rate class as a result of the addition of the 2019 incremental capital funding rate riders. Bill impacts as compared to the total bill including HST range from under 0.1% for Street Lighting to 0.3% for Unmetered.

Table 116 – ICM Bill Impacts (Total Bill) – PowerStream RZ

Rate Class	Unit	kWh	kW	ICM Rate Rider Incl HST	% Increase vs. Total Bill
Residential	kWh	750		$ 0.21	0.19%
General Service under 50 kW	kWh	2,000		$ 0.43	0.15%
General Service 50 to 4999 kW	kW	80,000	250	$ 10.06	0.07%
Large Use	kW	2,800,000	7,350	$ 189.97	0.04%
Unmetered	kWh	150		$ 0.08	0.27%
Sentinel Lights	kW	180	1	$ 0.12	0.29%
Street Lighting	kW	280	1	$ 0.06	0.12%

With respect to the PowerStream RZ, Alectra Utilities is requesting ICM funding for certain discrete and incremental capital projects that are considered non-discretionary and anticipated to come into service in 2019. Each discrete project that forms part of the ICM funding request is summarized above. For detailed project information, please refer to the business cases included as Attachment 31.

SUMMARY OF BILL IMPACTS

A summary of bill impacts for the typical customer by rate class is presented in Tables 117 to 119 below. These bill impacts are inclusive of the ICM rate rider and increase as a result of the implementation of the Price Cap IR mechanism in 2019. Attachment 24 provides a detailed summary of the bill impacts for each customer class for 2019.

Table 117 – Distribution Bill Impacts by Rate Class – PowerStream RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ 0.18	0.6%
GS<50	kWh	2,000	$ 1.87	2.7%
GS>50	kW	250	$ 37.66	3.1%
Large User	kW	7,350	$ (242.27)	(1.1)%
Street Lighting	kW	1	$ 1.38	16.8%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

Table 118 – Distribution Bill and Rate Rider Impacts by Rate Class – PowerStream RZ

Distribution Bill and All Rate Rider Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.74)	(2.5)%
GS<50	kWh	2,000	$ (0.54)	(0.8)%
GS>50	kW	250	$ (501.34)	(30.5)%
Large User	kW	7,350	$ (5,074.16)	(35.1)%
Street Lighting	kW	1	$ (0.71)	(6.6)%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

1 **Table 119 – Total Bill Impacts by Rate Class (before HST) – PowerStream RZ**

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.90)	(0.9)%
GS<50	kWh	2,000	$ (14.95)	(5.4)%
GS>50	kW	250	$ (1,078.61)	(8.9)%
Large User	kW	7,350	$ (25,277.59)	(6.8)%
Street Lighting	kW	1	$ (2.74)	(5.8)%

2 Table excludes the impact of HST (13%) & Provincial Rebate (8%)

CONCLUSION

Alectra Utilities respectfully requests that the Board approve the relief sought for the PowerStream RZ in this application.

ENERSOURCE RATE ZONE

MANAGER'S SUMMARY

Alectra Utilities is applying for distribution rates and other charges in the Enersource RZ, pursuant to a Price Cap IR, effective January 1, 2019. This application impacts customers in the City of Mississauga.

Alectra Utilities has completed the IRM Model for the Enersource RZ and will update the Application to include the 2019 IRM Rate Generator Model ("2019 RGM") when published by the OEB. This Application has been prepared in accordance with the updated *Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications* (the "Chapter 3 Filing Requirements"), dated July 20, 2017, including the key OEB reference documents listed therein, the Letter from the Board to Licensed Electricity Distributors *re: I. Updated Filing Requirements; and, II. Process for 2018 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications,* dated July 20, 2017.

Alectra Utilities also applies for incremental capital funding for the Enersource RZ in accordance with the OEB's: the Chapter 3 Filing Requirements*;* the MAADs Handbook; the OEB's *Handbook for Utility Rate Applications* (the "Rate Handbook"), dated October 13, 2016; the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014; and the subsequent *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016.

Relief Sought in This Application

Alectra Utilities is seeking Board approval for the following in the Enersource RZ:

a. 2019 distribution rates effective January 1, 2019 based on 2018 rates adjusted by the Board's IRM Price Cap Index Adjustment Mechanism formula;

b. The continuation of the implementation of the new distribution rate design for residential electricity customers;

c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2019 to December 31, 2019;

d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

e. The clearance of the balance in the 1580 Account RSVA – Sub Account CBR Class B attributed to new Class A and new Class B customers as of July 1, 2017, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. The refund of the net financial impact of the new capitalization policy in 2017 through rate rider over a one year period effective January 1, 2019;

g. An adjustment to the retail transmission service rates effective January 1, 2019;

h. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers;

i. Disposition of LRAMVA amounts related to CDM activities in 2016 over a one-year period;

j. Incremental capital rate riders effective January 1, 2019 until the next rebasing application; and,

k. Current (i.e., 2018) rates provided in Attachment 35 be declared interim effective January 1, 2019, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2019.

ANNUAL PRICE CAP ADJUSTMENT MECHANISM

As part of the RRFE, the Board initiated a review of utility performance per the "Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379)" proceeding. As part of this proceeding the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board, *"Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board*". The original PEG Report was issued on May 3, 2013, and established the parameters for use to determine the Price Cap Index for the 4th Generation IRM including: a productivity factor of 0.00%, the approach to determine the Industry Specific Inflation Factor (replacing the 3rd Generation IRM GDP-IPI inflation factor), and the initial stretch factor assignments.

Stretch Factor

The Stretch Factor assignments for 2019 IRM filers have not yet been updated by the Board. Alectra Utilities has used a Stretch Factor of 0.3% for the Enersource RZ in this Application in accordance with the most recent PEG Report, issued on August 17, 2017. The August 2017 report placed Alectra Utilities' Enersource RZ in Group III for the purpose of calculating stretch factors for 2018.

Inflation Factor

The Industry Specific Inflation Factor for 2019 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor for the Enersource RZ published for 2018 IRM filers, i.e. 1.2%, as an estimate for 2019.

Alectra Utilities will update the IRM Model for the Enersource RZ with the 2019 stretch factor and inflation factor in order to calculate the Price Cap Index once these factors are published by the Board.

The Price Cap Index as determined in the IRM Model, filed as Attachment 38, is 0.9%, is identified in Table 120, below.

Table 120 – Calculation of Price Cap Index – Enersource RZ

Factor	%
Inflation Factor	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.30%
Price Cap Index	**0.90%**

The Price Cap Index of 0.9% has been applied to Alectra Utilities' 2018 Service Charges and Distribution Volumetric Rates by rate class for the Enersource RZ to determine the 2019 Service Charges and Distribution Volumetric Rates. Alectra Utilities' 2019 Proposed Tariff of Rates and Charges for the Enersource RZ is filed as Attachment 36.

RATE DESIGN FOR RESIDENTIAL ELECTRICITY CUSTOMERS

On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Customers*, which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year period commencing in 2016 and ending in 2019.

The Board directed that *"Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral*."

Enersource incorporated the first year transition adjustment in its proposed rates for 2016 in a manner consistent with OEB policy. As per the Partial Decision and Order for the 2016 IRM Application[12]: "*The OEB approves the proposed transition over a four year period. The OEB finds that the increase to the monthly fixed charge and to low consumption consumers are consistent with OEB policy and approves the increase as calculated in Enersource's evidence*."

Enersource incorporated the second year transition adjustment in its proposed rates for 2017 in a manner consistent with OEB policy. As per the Decision and Order for the 2017 IRM Application[13], the Board confirmed that "*the proposed 2017 increase to the monthly fixed charge is in accordance with the OEB's 2015-0065 Decision and residential rate design policy. The results of the monthly fixed charge, and total bill impact for low volume customer tests show no mitigation is required. The OEB approves the increase as proposed by the applicant and calculated in the final rate model*".

Alectra Utilities incorporated the third year transition adjustment in its proposed rates for 2018 in a manner consistent with OEB policy. As per the Decision and Order for the 2018 EDR Application[14], the Board confirmed that "*the proposed 2018 increase to the monthly fixed charge is in accordance with the OEB's 2015-0065 Decision and residential rate design policy. The results of the monthly fixed charge, and total bill impact for low volume customer tests show no*

[12] EB–2015-0065, p 10.

[13] EB–2016-0002, p.12.

[14] EB–2017-0024, p.76.

mitigation is required. The OEB approves the increase as proposed by the applicant and calculated in the final rate model".

Alectra Utilities has incorporated the final transition adjustment for the Enersource RZ in its proposed rates for 2019. The calculation of the proposed residential fixed and variable rates is identified in Tab 16. Rev2Cost-GDPIPI of the IRM Model filed as Attachment 38.

The Board instructed distributors that, for the purposes of implementing the new fixed rate design, a 10% test will be applied to customers who consume much less electricity than the typical residential customers.

This will allow any mitigation plans to be tailored to those customers who use the least power and whose bills will likely increase due to the shift in the fixed rates. If a customer at the 10^{th} consumption percentile level of electricity has a bill impact of 10% or higher, the distributor must make a proposal for a rate mitigation plan.

Alectra Utilities confirms that the Residential monthly service charge increase of $2.57 is below the threshold of $4 per month identified in the Board's policy. Accordingly, rate mitigation is not necessary since a customer at the lowest decile of electricity consumption will not have a bill impact of 10% or higher.

Alectra Utilities has followed the Board's direction to assess the combined effect of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service for the Enersource RZ by evaluating the total bill impact for a residential customer at the 10^{th} consumption percentile. The following is a description of the method that Alectra Utilities used to derive the 10^{th} consumption percentile.

1. Total 2017 actual annual residential consumption by premise/account was extracted from the Customer Information System ("CIS");
2. Consumption that straddled the beginning and end of the year was prorated to isolate 2017 consumption only;
3. Consumption for residential customers with active service for the full year was extrapolated from the total data source (e.g. customers with two months of service were excluded);

4. The average monthly consumption by premise/account was calculated for the customer identified above; and

5. The data set which was comprised of 187,853 records was sorted from smallest to largest by average monthly consumption. An index of 18,785 was calculated by taking the total number of records in the data set, multiplied by 10% which corresponds to an average monthly consumption of 308 kWh, which is the 10th consumption percentile for the Enersource RZ residential customers.

Alectra Utilities has provided the bill impact for a Residential customer thatconsumes 308 kWh monthly in Table 121, below. The monthly service charge increased by $2.57 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 2.08%.

1 **Table 121 – 10th Consumption Percentile Residential Customer Bill Impact (308 kWh) – Enersource RZ**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	**10th percentile**
Consumption	**308**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0360**	
Proposed/Approved Loss Factor	**1.0360**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	**$ 21.61**	1	$ 21.61	$ 24.18	1	$ 24.18	$ 2.57	11.89%
Distribution Volumetric Rate	**$ 0.0035**	308	$ 1.08	$ -	308	$ -	$ (1.08)	-100.00%
Fixed Rate Riders	**$ 0.93**	1	$ 0.93	$ 0.69	1	$ 0.69	$ (0.24)	-25.81%
Volumetric Rate Riders	**-$ 0.0002**	308	$ (0.06)	$ -	308	$ -	$ 0.06	-100.00%
Sub-Total A (excluding pass through)			$ 23.56			$ 24.87	**$ 1.31**	**5.58%**
Line Losses on Cost of Power	**$ 0.0822**	11	$ 0.91	$ 0.0820	11	$ 0.91	$ (0.00)	-0.21%
Total Deferral/Variance Account Rate Riders	**-$ 0.0008**	308	$ (0.23)	-$ 0.0011	308	$ (0.35)	$ (0.12)	52.00%
GA Rate Riders								
Low Voltage Service Charge	**$ 0.0002**	308	$ 0.06	$ 0.0002	308	$ 0.06	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ 0.57**	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24.87**			**$ 26.06**	**$ 1.19**	**4.79%**
RTSR - Network	**$ 0.0076**	308	$ 2.34	$ 0.0076	308	$ 2.34	$ -	0.00%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0071**	308	$ 2.19	$ 0.0072	308	$ 2.22	$ 0.03	1.41%
Sub-Total C - Delivery (including Sub-Total B)			**$ 29.40**			**$ 30.62**	**$ 1.22**	**4.16%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	319	$ 1.15	$ 0.0036	319	$ 1.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	319	$ 0.10	$ 0.0003	319	$ 0.10	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	**$ 0.0650**	200	$ 13.01	$ 0.0650	200	$ 13.01	$ -	0.00%
TOU - Mid Peak	**$ 0.0950**	52	$ 4.97	$ 0.0940	52	$ 4.92	$ (0.05)	-1.05%
TOU - On Peak	**$ 0.1320**	55	$ 7.32	$ 0.1320	55	$ 7.32	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 56.20**			**$ 57.37**	**$ 1.17**	**2.08%**
HST	13%		$ 7.31	13%		$ 7.46	$ 0.15	2.08%
8% Provincial Rebate	-8%		$ (4.50)	-8%		$ (4.59)	$ (0.09)	2.08%
Total Bill on TOU			**$ 59.01**			**$ 60.23**	**$ 1.23**	**2.08%**

2

ELECTRICITY DISTRIBUTION RETAIL TRANSMISSION SERVICE RATES

The Board's *Guideline for Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") (G-2008-0001) was issued June 28, 2012. On January 25, 2018, the OEB issued its Decision and Order in respect of the 2018 Uniform Transmission Rates ("UTRs") (EB-2017-0359). On December 21, 2016, the OEB issued its Decision and Order in respect of Hydro One Networks Inc. ("HONI") application for electricity distribution rates and other charges beginning January 1, 2017, which contain HONI's STRs at page 10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 122, below.

Table 122 – Current Board-Approved UTRs and STRs – Enersource RZ

UTRs	$
Network Service Rate	$3.61
Line Connection Service Rate	$0.95
Transformation Connection Service Rate	$2.34
STRs	**$**
Network Service Rate	$3.1942
Line Connection Service Rate	$0.7710
Transformation Connection Service Rate	$1.7493

Alectra Utilities has updated Tabs 11-15 of the IRM Model for the Enersource RZ filed as Attachment 38 to incorporate i) the most recent UTRs and STRs approved by the Board; and ii) an update to Alectra Utilities demand in the Enersource RZ from 2016 to 2017 actual values. The RTSRs are calculated in Tab 16 of the IRM Model.

Alectra Utilities will update the RTSRs for the Enersource RZ should the actual UTRs and STRs be approved prior to the OEB issuing the final rate order for this application.

REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative (*EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met. Consistent with a Letter from the Board to Licensed Electricity Distributors re: *Process for 2015 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*, dated July 25, 2014, distributors may also elect to dispose of Group 1 account balances below the threshold.

Group 1 accounts consist of the following Uniform System of Accounts ("USoA"):

- 1550 - Low Voltage Account;
- 1551 - SME Charge Account;
- 1580 - RSVA Wholesale Market Service Charge Account;
- 1584 - RSVA Retail Transmission Network Charge Account;
- 1586 - RSVA Retail Transmission Connection Charge Account;
- 1588 - RSVA Power Account;
- 1589 - RSVA Global Adjustment Account;
- 1590 - Recovery of Regulatory Asset Balances Account (if applicable); and
- 1595 - Disposition and Recovery/Refund of Regulatory Balances Account.

The Group 1 balances for Alectra Utilities' Enersource RZ as of December 31, 2017, in the amount of ($6,523,939), have been adjusted for the following items to determine the amount for disposition of $2,918,724 as identified in Table 123, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition as directed in the OEB's letter dated May 23, 2017 on

the *"Guidance on the Disposition of Accounts 1588 and 1589"*. For the Enersource RZ an adjustment of ($998,801) and $2,871,035 has been made to Account 1588 and Account 1589 respectively, to reflect RPP settlement true-up claims for 2017 that were settled in 2018. These amounts have been entered into the IRM model, Tab "3. Continuity Schedule" Column "Principal Adjustments during 2017". See Table 123 below for a summary of this adjustment. Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;

- Only Class B Capacity Based Recovery ("CBR") amounts are to be disposed of through this rate proceeding as directed by the OEB in its *Accounting Guidance on Capacity Based Recovery* issued July 25, 2016; and

- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e. the amount for disposition includes 2018 projected carrying charges).

Table 123 – Group 1 Account Balances for Disposition – Enersource RZ

Description	Amount
Group 1 Account Balances as of December 31, 2017	**($6,523,939)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers	($7,468,139)
RPP Settlement True-up Claims Adjustment	$1,872,234
Add Projected Carrying Charges	$50,556
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	$51,734
Adjusted Group 1 Account Balances for Disposition - Recovery from Customers	**$2,918,724**

Alectra Utilities has computed the disposition threshold for the Enersource RZ, based on the adjusted Group 1 balances to be $0.00041/kWh, as identified in Table 124 below. Alectra Utilities requests disposition of its Group 1 account balances for the Enersource RZ in this Application.

Table 124 - Calculation of Disposition Threshold – Enersource RZ

Description	Account	Amount
Low Voltage	1550	$4,728,615
Smart Meter Entity Charge	1551	($61,093)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	($244,664)
RSVA - Wholesale Market Service Charge excluding CBR	1580	($14,339,260)
RSVA - Retail Transmission Network Charge	1584	$1,401,888
RSVA - Retail Transmission Connection Charge	1586	$400,726
RSVA - Power	1588	$923,013
RSVA - Global Adjustment	1589	$724,646
Disposition and Recovery/Refund of Regulatory Balances	1595	($57,810)
Group 1 Account Balances as of December 31, 2017		**($6,523,939)**
Subtract 2018 Annual Filing Disposition (EB-2017-0024) - Refund to Customers		($7,468,139)
RPP Settlement True-up Claims Adjustment		$1,872,234
Add Projected Carrying Charges		$50,556
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		$51,734
Adjusted Group 1 Account Balances for Disposition - Recovery from Customers		**$2,918,724**
2017 kWhs		7,066,542,026
Threshold Test $/kWh		**$0.00041**

Alectra Utilities has completed Tab 3. Continuity Schedule of the IRM Model for the Enersource RZ filed as Attachment 38. Alectra Utilities has reconciled the Group 1 balances for the Enersource RZ filed in the 2017 RRR, section 2.1.7 as identified in Table 125 below. Alectra Utilities confirms that the last Board approved balance of ($7,468,139) for the Enersource RZ has been transferred to Account 1595 (as identified in Alectra Utilities 2018 EDR Application EB-2017-0024). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2017 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rate of 1.5% for 2018 Q1 and 1.89% for 2018 Q2-Q4 were used to calculate forecasted interest for 2018 No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 125 – Deferral and Variance Account Reconciliation – Enersource RZ

Account Description	Account	Principal Amounts as of Dec 31, 2017	Carrying Charges to Dec 31, 2017	Principal Disposition during 2018 - instructed by Board EB-2017-0024	Interest Disposition during 2018 - instructed by Board EB-2017-0024	Projected Carrying Charges to Dec 31, 2018	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims Adjustment	Projected Carrying Charges to December 31, 2018	1595 Balances Not Claimed in 2019	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	4,670,070	58,545	(2,290,282)	(55,806)	42,658	2,425,185				2,425,185
Smart Meter Entity Charge	1551	(60,256)	(836)	33,444	904	(481)	(27,225)				(27,225)
RSVA - Wholesale Market Service Charge - CBR B	1580	(240,043)	(4,621)	275,214	7,212	630	38,393				38,393
RSVA - Wholesale Market Service Charge excluding CBR	1580	(14,151,704)	(187,556)	6,868,015	175,054	(130,560)	(7,426,751)				(7,426,751)
RSVA - Retail Transmission Network Charge	1584	1,396,122	5,767	568,201	(126)	35,210	2,005,174				2,005,174
RSVA - Retail Transmission Connection Charge	1586	382,215	18,511	(333,842)	(14,778)	867	52,973				52,973
RSVA - Power	1588	967,857	(44,844)	350,628	27,687	23,634	1,324,962	(998,801)	(17,904)		308,257
Sub-total not including RSVA Power Global Adjustment		(7,035,741)	(155,034)	5,471,380	140,148	(28,041)	(1,607,289)	(998,801)	(17,904)		(2,623,994)
RSVA - Power Global Adjustment	1589	664,452	60,194	1,860,431	(10,117)	45,259	2,620,219	2,871,035	51,463		5,542,717
Total including RSVA Power Global Adjustment		(6,371,289)	(94,840)	7,331,811	130,031	17,217	1,012,930	1,872,234	33,560		2,918,724
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	(72,356)	52,620	58,585	(52,288)	(247)	(13,685)			(13,685)	-
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	1,444	(39,519)	-	-	26	(38,049)			(38,049)	-
Total 1595		(70,912)	13,101	58,585	(52,288)	(221)	(51,734)	-	-	(51,734)	-
Total Group 1		**(6,442,200)**	**(81,739)**	**7,390,396**	**77,743**	**16,996**	**961,195**	**1,872,234**	**33,560**	**(51,734)**	**2,918,724**
Total Amount for Disposition		**(6,442,200)**	**(81,739)**	**7,390,396**	**77,743**	**16,996**	**961,195**	**1,872,234**	**33,560**	**(51,734)**	**2,918,724**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year"*.

<u>Wholesale Market Participants ("WMPs)</u>

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

<u>Global Adjustment and Capacity Based Recovery ("CBR") Disposition</u>

Alectra Utilities has also established separate rate riders for the Enersource RZ to dispose of the global adjustment ("GA") and Capacity Based Response ("CBR") account balances. These rate riders are applicable for non-RPP Class B customers only. Alectra Utilities Class A customers in the Enersource RZ are invoiced the actual GA and, as such, none of the variance in the GA account balance should be attributed to these customers.

There were 74 Alectra Utilities customers in the Enersource RZ who newly qualified as Class A customers effective July 1, 2017 under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA and CBR as Class B customers up to and including June 30, 2017; and paid GA and CBR as Class A customers from July 1, 2017 to December 31, 2017. As such, these customers should be allocated only the portion of the GA and CBR account balances which accrued prior to their classification as Class A customers (i.e. from January 1, 2017 to June 30, 2017).

These GA and CBR amounts will be settled through twelve equal adjustments to bills as directed in the Chapter 3 Filing Requirements. These customers will not be charged the CBR or GA rate riders.

There were two Alectra Utilities customers, in the Enersource RZ, that ceased to qualify as a Class A customer effective July 1, 2017, under the IESO's expansion of Industrial Conservation Initiative ("ICI"). These customers paid GA and CBR as Class A customer up to and including

June 30, 2017; and paid GA and CBR as a Class B customer from July 1, 2017 to December 31, 2017. These customers should be allocated only the portion of the GA and CBR account balance which accrued after its reclassification to a Class B customer (i.e. from July 1, 2017 to December 31, 2017).

The total GA balance to be disposed of is $5,542,717, of which $4,897,520 will be disposed of via rate riders; and $543,715 and $101,483 will be disposed of via specific bill adjustments for the 74 new Class A customers and 2 new Class B customers respectively as discussed above. Tab “6a GA Allocation Class A” in the IRM Model identify the detailed calculation of the bill adjustment of $543,715 and $101,483, respectively.

The total CBR balance to be disposed of is $38,393, of which $35,834 will be disposed of via rate rider; and $2,156 and $403 will be disposed of via specific bill adjustments for the 74 new Class A customers and 2 new Class B customes as discussed above. Tab “7A CBR Allocation _Class A” and “7B CBR Allocation_new Class B” in the IRM model identify the detailed calculation of the total bill adjustments of $2,156 and $403, respectively.

Alectra Utilities requests disposition of its GA balance for the Enersource RZ of $645,198 and its CBR balance of $2,559 related to its 74 new Class A customers and two new Class B customers (effective July 1, 2017) through the bill adjustments identified in the IRM Model.

Table 126 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Table 126 – Disposition of GA and CBR Balances – Enersource RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	$4,897,520
Global Adjustment - New Class A Customers July 1/2017	$543,715
Global Adjustment - New Class B Customers July 1/2017	$101,483
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**$5,542,717**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2017- Dec 31/2017	$35,834
Capacity Based Recovery - New Class A Customers July 1/2017	$2,156
Capacity Based Recovery - New Class B Customers July 1/2017	$403
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**$38,393**

A summary of the rate riders applicable to each group of customers is identified in Table 127 below.

Table 127 – Rate Riders by Customer Group – Enersource RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2017 - Dec 31, 2017)	x	x			
Class B non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class A (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class A non-RPP (Jan 1, 2017 - Jun 30, 2017)/Class B (Jul 1, 2017 - Dec 31, 2017) Customers	x	x			x
Class B non-RPP (Jan 1, 2017 - Dec 31, 2017) Customers	x	x	x	x	
Class B RPP Customers	x	x	x		

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges and retail transmission connection charges

Class A customers (who were Class A from January 1 – December 31, 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Class B, non-RPP customers (who were Class A customers for only part of 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class A, non-RPP customers (who were Class B customers for only part of 2017) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers (who were Class B from January 1 – December 31, 2017) are charged the sum of DVA Rate Riders 1 and 2; the GA Rate Rider; and the CBR B Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR B Rate Rider.

The Group 1 Disposition by customer group is identified in Table 128 below. The amount to be disposed of by rate rider is $2,270,967 and the amount to be disposed of via customer specific bill adjustments is $647,757 (debits of $645,198 GA and $2,559 CBR).

Table 128 – Group 1 Disposition by Customer Group – Enersource RZ

Description	Account	Amount
Low Voltage	1550	$2,425,185
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($27,225)
Retail Transmission Network Charge	1584	$2,005,174
Retail Transmission Connection Charge	1586	$52,973
Disposition and Recovery/Refund of Regulatory Balances	1595	$0
All Customers - DVA Rate Rider 1		**$4,456,107**
Power	1588	$308,257
Wholesale Market Service Charge excluding CBR	1580	($7,426,751)
All Customers ex WMPs - DVA Rate Rider 2		**($7,118,494)**
Wholesale Market Service Charge - CBR Class B	1580	$35,834
Wholesale Market Service Charge - New Class A/B Customers July 1/2017		$2,559
All Class B Customers ex WMPs - CBR B Bill Adjustment	**1580**	**$38,393**
Global Adjustment - Non-RPP Class B Customers Jan 1/2017 -Dec 31/2017	1589	$4,897,520
Global Adjustment - New Class A/B Customers July 1/2017	1589	$645,198
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**$5,542,717**
Total (Repayment to)/Recovery from Customers		**$2,918,724**
Disposition via Rate Rider		$2,270,967
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2017		$645,198
Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2017		$2,559

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2017 actuals reported in Alectra Utilities' 2017 RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4. through 8. in the IRM Model filed as Attachment 38. Table 129 below summarizes the deferral and variance rate riders by class. As identified in the Chapter 3 Filing Requirements, "*Effective in 2017, the billing determinant and all the rate riders for the GA will be calculated on an energy basis (kWhs) regardless of the billing determinant used for distribution rates for the particular class*."

Table 129 – Proposed Rate Riders by Class – Enersource RZ

Customer Class	Deferral/Variance Account Rate Rider		Deferral/Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B Jan 1 - Dec 31, 2017		CBR B Rate Rider Class B Consumer Jan 1 - Dec 31, 2017	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0004)				0.0017		0.00001	
General Service Less Than 50 kW	(0.0004)				0.0017		0.00001	
General Service 50 To 499 kW		0.2188		(0.3484)	0.0017			0.00237
General Service 500 To 4,999 kW		0.2760		(0.4388)	0.0017			0.00278
Large Use		(0.2100)			0.0017			0.00001
Standby Power	0.0000							
Unmetered Scattered Load	(0.0004)				0.0017			0.00001
Street Lighting		(0.1354)			0.0017			0.00248

Alectra Utilities requests disposition of its adjusted Group 1 balances for the Enersource RZ of $2,270,967 identified in Table 128, through the rate riders identified in Table 129 above. Alectra Utilities also requests disposition of the CBR B rate rider to the fifth decimal place for the Enersource RZ. The OEB indicates in the Treatment of Negligible Rate Adders and Rate Riders on page 26 of the Chapter 3 Filing Requirements that:

> *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.*

However, Alectra Utilities proposes that the CBR B balance be cleared with a volumetric rate rider to five decimal places in 2018 for the Enersource RZ. 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. The OEB approved this approach in Alectra Utilities' 2018 EDR Application.

For a typical RPP Residential customer using 750 kWh/month, the total bill impact of the proposed Group 1 rate riders is a decrease of ($0.86)/month or (0.79%) on total bill.

GA Analysis Workform

The GA Analysis Workform ("GA Workform") for the Enersource RZ is filed as Attachment 39. The GA Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in Account 1589 in a specific year is reasonable.

The principal activity in Account 1589 recorded in 2017 was $2,524,883 as identified in Table 130 below. The principal activity balance, after known adjustments of $2,871,035 was $5,395,918. This is compared to the expected principal balance in Account 1589 of $3,136,226 as calculated in Attachment 39, which results in an unreconciled difference of $2,259,693. This represents 0.69% of Alectra Utilities 2017 IESO purchases in the Enersource RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 130 – GA Workform Summary Enersource RZ

Description	Amount
Principal Activity in RSVA(GA)	$2,524,883
Add Known Adjustments	$2,871,035
Adjusted Principal Activity in RSVA(GA)	$5,395,918
Expected Principal Activity in RSVA(GA)	$3,136,226
Variance $	$2,259,693
Total 2017 IESO Purchases	$329,524,114
Absolute Variance as a % of IESO Purchases	0.69%

SETTLEMENT PROCESS WITH THE IESO

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its settlements process with the IESO or host distributor. Distributors must specify the Global Adjustment rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. Enersource provides its settlement process with the IESO below.

The manner in which Alectra Utilities settles with the IESO for the Enersource RZ is provided in Table 131 below and depends on the following: (i) whether the customer is a Regulated Price Plan ("RPP") consumer; and (ii) whether the customer is a Class A or Class B consumer. It is not dependent on the rate class.

Table 131 – Settlement Process with the IESO – Enersource RZ

Customer	GA Rate used for Billing	GA Rate used to Record Cost	Settlement Process	Consumption Estimates	Impact on GA Variance Account
Class A	Actual	Actual	Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	Class A consumption actuals are submitted to the IESO - actuals are known at the time of submission; therefore an estimate is not required	none
Class B non-RPP	1st Estimate	Actual	Alectra Utilities pays the IESO Actual GA and bills customers 1st estimate GA - no further settlement with the IESO is required	Class B non-RPP consumption is not submitted to the IESO; however an estimate is used in order to calculate the RPP consumption used in the RPP vs. Market Price Claim[2]	Difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP consumers on disposal of the GA Variance Account
Class B RPP	RPP Time-of-Use ("TOU") or Tiered Rates[1]	Actual	Alectra Utilities pays the IESO Actual GA and bills customers RPP rates - Alectra Utilities settles with the IESO on an monthly basis via the RPP vs. Market Price Claim[2]	RPP consumption is estimated and provided to the IESO as part of the RPP vs. Market Price Claim[2] provided to the IESO	none

1. GA is not billed separately for Class B RPP customers; incorporated into RPP Rates

2. RPP vs. Market Price Claim is discussed in further detail below

<u>Class A Customers</u>: The IESO publishes the actual GA for a month on the tenth business day of the following month. The GA costs invoiced to Alectra Utilities for the Enersource RZ by the IESO represents the total provincial system-wide GA costs for the month multiplied by Alectra

Utilities' Enersource RZ's peak demand factor, which is the aggregate of its Class A customers' peak demand factors. No further settlement with the IESO is required. Alectra Utilities bills Class A customers in the Enersource RZ the GA based on their respective peak demand factors or their percentage contribution to the top five peak Ontario demand hours, and as such, there is no variance in the GA account balance attributed to these customers. Alectra Utilities submits total Class A actual consumption for the Enersource RZ to the IESO on a monthly basis as part of the monthly RPP vs Market Claim submission.

Class B non-RPP Customers: Class B non-RPP customers in the Enersource RZ are billed by Alectra Utilities throughout the month. These customers pay the spot market price for energy – either the Weighted Average Hourly Spot price ("WAHSP") or the Hourly Ontario Energy Price ("HOEP"); and the GA. Alectra Utilities bills its Class B non-RPP customers in the Enersource RZ using the IESO's 1st estimate for GA for the month which is published by the IESO on the last business day of the preceding month. Alectra Utilities pays the IESO Class B GA for the Enersource RZ based on its actual Class B volume at the actual Class B rate. No further settlement with the IESO is required. Any difference between GA revenues and GA costs are recorded in the GA variance account to be recovered from or refunded to Class B non-RPP customers. Alectra Utilities allocates the Class B GA charged by the IESO for the Enersource RZ to its RPP and non-RPP customers based on consumption. Class B non-RPP consumption is equal to the consumption for all customers billed at spot pricing (interval metered and non-interval metered) less the consumption for Class A customers. The determination of Class B RPP consumption is discussed in further detail, below.

Class B RPP Customers: Class B RPP customers are billed by Alectra Utilities for the Enersource RZ throughout the month at RPP TOU or Tiered Rates. The difference between how much Alectra Utilities recovers from RPP customers for the Enersource RZ at these rates and the amount Alectra Utilities pays for the commodity supply in the wholesale marketplace for the Enersource RZ to the IESO, is recorded and managed in an account by the IESO.

On a monthly basis, this difference is settled with the IESO via the RPP vs. Market Price claim. The amount submitted is reflected on the following month's IESO invoice as either a debit (Alectra Utilities collected more revenue from RPP customers in the Enersource RZ than it paid for electricity) or a credit (Alectra Utilities collected less revenue from RPP customers for the Enersource RZ than it paid for electricity). Alectra Utilities compares the amount collected from RPP customers (kWh billed at TOU or Tiered Pricing) for the Enersource RZ to the amount it pays to the IESO for electricity for that same volume, to determine this amount. There are two components to the RPP vs. Market Price claim:

1. Estimated RPP settlement amount for the current month; and
2. A quarterly true-up adjustment to the RPP settlement amount)

1. <u>Estimated Claim for the Current Month</u>

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available for the respective month end due to a billing lag, Alectra Utilities estimates the eligible kWh from each RPP customer for the Enersource RZ based on a combination of billed accounts which are based on smart meter data plus an unbilled component at month end. The unbilled component is based on the last bill prior to month end extrapolated to the end of the current month. Low volume consumption is allocated between RPP customers on tiered pricing and on TOU pricing based on recent CC&B billing system consumption data. Consumption for customers on tiered pricing is allocated between Tier 1 and 2, based on the same analysis of billing data and an allocation of consumption by TOU periods is based on analysis of recent CC&B billing system TOU bills. Alectra Utilities uses this consumption to calculate the RPP revenue at RPP rates and the RPP cost for the Enersource RZ to determine the RPP claim for the current month. RPP cost consists of the commodity cost and the GA cost. Commodity cost is calculated as the RPP kWhs multiplied by the weighted average hourly Ontario price based on the net system load for the target month. GA cost is calculated as the RPP kWhs multiplied by the GA 2nd estimate from IESO.

2. Quarterly True-up of RPP Claim using Actual Billed Consumption

True-ups are performed quarterly to allow for the completion of all billing cycles for RPP customers. The cumulative billed RPP amounts for the previous quarter are compared to the monthly RPP vs. market price claims submitted for the corresponding true-up period and an adjustment is made to the Power 1588 variance account. For GA, both the volume and GA rates are trued-up quarterly. The RPP cumulative billed data is compared to the submitted values in Form 1598, and the 2nd estimate rates used in Form 1598 is adjusted/trued-up to the actual GA rates. The net effect of volume and GA price variances is adjusted to GA 1589 variance account.

CAPITALIZATION POLICY

Alectra Utilities implemented a new capitalization policy in 2017 (as a result of the consolidation, and as required under the International Financial Reporting Standards (“IFRS”)) to align the capitalization policies for the Alectra Utilities rate zones.

IFRS 10 *Consolidated Financial Statements,* states that uniform accounting policies have to be adopted for like transactions in a group of companies. Further, IFRS 3 *Business Combinations* prescribes that the accounting policies of the parties to the merger should align to the acquirer’s policy. IFRS 3 provides guidance on identifying the acquirer by assessing the relative voting rights in the combined entity after the merger; the acquirer being the combining entity whose owners, as a group, receive the largest portion of voting rights in the combined entity.

For the predecessor companies that formed Alectra Utilities, PowerStream is the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities adopted the PowerStream capitalization policy.

The OEB established three new deferral accounts to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs, in Procedural Order No. 3, as part of Alectra Utilities’ 2018 EDR Application proceeding. In the 2018 EDR Application Decision, the OEB stated that: “*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, 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.* Further, the OEB stated that: “*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*[15]*."*

The total 2017 net impact of the financial differences arising from the change to Alectra Utilities' capitalization policy in the Enersource rate zone is an increase in revenue requirement of $1.2MM.

The net impact of the capitalization policy change includes the following items:

- The actual impact on OM&A expenditures in each year following the change in capitalization policy until rebasing;
- The actual impact on depreciation expense over the life of the underlying assets as a result of the increase/decrease in capitalization costs;
- The impact on income tax or PILs for the amount paid to taxation authorities; and
- The annual return on the cumulative impact from the annual change in capitalization.

Alectra Utilities proposes to refund this amount over a one year period from all customers in the Enersource rate zone. Tables 132 to 135 below provide the total 2017 impact of the change in capitalization policy for the Enersource RZ.

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Table 132 – Capitalization Policy Total Net Financial Impact Enersource RZ

Capitalization Policy Impact	2017 Actual
Total OM&A Impact	$1,866,041
Total Depreciation Impact	($23,968)
Total PILs Impact	($474,721)
Total Return on Capital Impact	($119,852)
Total Net Impact	**$1,247,499**

Table 133 – Capitalization Policy Total OM&A and Depreciation Impact Enersource RZ

OM&A Impact_ERZ	2017 Actual
Direct Labour Costs	$519,256
Benefit Costs	($48,759)
Material Handling Costs	$916,805
Fleet Costs	$478,739
Total OM&A Impact	**$1,866,041**

Depreciation Impact_ERZ	2017 Actual
Depreciation Expense	($23,968)
Total Depreciation Impact	**($23,968)**

Table 134 – Capitalization Policy Total PILs Impact Enersource RZ

PILs Impact_ERZ	2017 Actual
OM&A Impact	$ 1,866,041
Depreciation Impact	($23,968)
NIBT	$1,842,072
Add back: Depreciation	$23,968
Deduct: CCA	($74,642)
Taxable income	$1,791,399
Income tax @ 26.5%	**($474,721)**

Table 135 – Capitalization Policy Total Return on Capital Impact Enersource RZ

Return on Capital_ERZ	2017
Increased capitalization	$1,866,041
Depreciation Expense	($23,968)
Increased Capital in Rate Base	$1,842,072
Deemed ShortTerm Debt %	4.00%
Deemed LongTerm Debt %	56.00%
Short Term Interest	2.08%
Long Term Interest	5.09%
Deemed ShortTerm Debt %	$73,683
Deemed Long Term Debt %	$1,031,561
Short Term Interest	$1,533
Long Term Interest	$52,521
Return on Rate Base - Interest	$54,053
Deemed Equity	$736,829
	8.93%
Return on Capital - Equity	$65,799
Return on Capital	**($119,852)**

Alectra Utilities is seeking Board approval for the capitalization policy rate riders, for the Enersource RZ, identified in Table 136 to refund the revenue requirement of $1,247,499 identified in Table 132 above. The revenue requirement has been allocated to rate classes based on the current allocation of revenue as provided in the Capitalization Policy Rate Rider Model for the Enersource RZ filed as Attachment 40. The revenue requirement for the residential class will be recovered via a fixed rate rider as per the OEB's letter issued July 16, 2015 (EB-2012-0410). Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in Attachment 40.

Table 136 – Capitalization Policy Rate Riders – Enersource RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	($0.23)	$0.00	kWh
General Service under 50 kW	($0.42)	($0.0001)	kWh
General Service 50 to 499 kW	($0.74)	($0.0447)	kW
General Service 500 to 4999 kW	($16.90)	($0.0230)	kW
Large Use	($133.24)	($0.0285)	kW
Unmetered	($0.09)	($0.0002)	kWh
Street Lighting	($0.01)	($0.1116)	kW

RENEWABLE GENERATION CONNECTION RATE PROTECTION

Enersource filed a basic Green Energy Plan (the “GEA Plan”) which was approved by the Board in Enersource’s 2013 cost of service application proceeding (EB-2012-0033). The GEA Plan identified the projects and expenditures associated with the connection of renewable generation to its system and discussed constraints on the ability to connect renewable generation. The GEA Plan was filed in accordance with the *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397), which requires distributors to identify the costs related to the connection of FIT and microFIT projects and/or to the implementation of a smart grid. The GEA Plan did not include any smart grid initiatives. Enersource records the revenues related to Renewable Generation in Account 1533, Renewable Generation Connection Funding Adder Deferral Account. Accordingly, all associated costs related to Renewable Generation are recorded in Account 1531, Renewable Connection Capital Deferral Account and Account 1532, Renewable Connection OM&A Deferral Account.

Attachment 41 includes the actual amounts for 2017 and provides an updated estimate for 2018 and 2019 Renewable Generation Connection funding and costs.

Alectra Utilities continues to connect renewable generators to its distribution system in the Enersource RZ. Table 137 below provides the total number of FIT and microFIT applications received by Alectra Utilities for the Enersource RZ as of the end of March, 2018. These figures include all projects listed on the IESO’s FIT Application Management Environment (“FAME”) and microFIT LDC Admin web portals, as well as all projects for which initial capacity checks have been requested to be performed by Alectra Utilities for the Enersource RZ, and which may or may not be registered with the IESO. Table 137 also provides a summary of the number of renewable energy projects connected as of the end of March, 2018, and the corresponding total installed capacity for those projects since inception in 2009.

Table 137 – Renewable Connections as of March 31, 2018

Type of Renewable Generation	Number of Applications Received	Total Number of Projects Connected	Total kW of Projects Connected
MicroFIT (≤10 kW)	1,986	670	5,167
FIT (>10 kW)	1,139	125	21,186
Total	**3,125**	**795**	**26,353**

Alectra Utilities' Renewable Generation Connection Funding Amount for the Enersource RZ includes a forecast of the total number of renewable generation projects to be connected. The estimates are shown in Table 138, below.

Table 138 – Actual/Forecast of Renewable Generation Project Connections – Enersource RZ

	2014	2015	2016	2017	March 2018 YTD	2018 Forecast	2019 Forecast
Actual/Forecast Number of Renewable Generation Projects Connected							
microFIT	41	119	117	178	31	100	0
FIT	26	16	9	36	13	13	3
Total	**67**	**135**	**126**	**214**	**44**	**113**	**3**
Actual/Forecast Total kW of Renewable Generation Projects Connected (kW)*							
microFIT	326	1,141	997	1,308	253	777	0
FIT	4,412	2,994	1,712	5,034	2,024	2,024	1,415
Total	**4,738**	**4,135**	**2,709**	**6,342**	**2,277**	**2801**	**1,415**
Actual/Forecast Number of Renewable Generation Projects Applications Received							
microFIT	176	383	165	267	4	4	0
FIT	62	227	34	0	3	3	0
Total	**238**	**610**	**199**	**267**	**7**	**7**	**0**

The forecasted microFIT connections in 2018 have increased from 30 projects, as outlined in the original forecast provided in 2018 IRM Rate Application (EB-2017-0024), to 100 projects, as shown in Table 138, mainly as a result of increased customer interest in the program. The 2018 forecast only accounts for projects initiated in 2017 and expected to be completed in 2018 as the procurement of the microFIT projects concluded in 2017.

The forecast for FIT projects for 2018 has increased to 13 projects, compared to 10 projects originally forecasted for 2018 as outlined in the original forecast provided in 2018 IRM Rate Application (EB-2017-0024). This is due to the delay of several projects that were originally projected to be completed in 2017.

Alectra Utilities is requesting the collection of renewable generation funding for the Enersource RZ of $153,726 in 2019, or $12,810 per month from all provincial ratepayers, as shown in Attachment 41.

DISPOSITION OF LRAM VARIANCE ACCOUNT

Alectra Utilities is applying for disposition of the balance in the LRAMVA account for the Enersource RZ resulting from its Conservation and Demand Management ("CDM") activities in 2016. The total amount requested for disposition is a debit of $1,773,859 including forecasted carrying charges of $59,930 through to December 31, 2018. Actual savings from CDM activities for 2016 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities most recent application for the recovery of lost revenues due to CDM activities for the Enersource RZ was filed in Alectra Utilities 2018 EDR Application (EB-2017-0024). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities for 2011 through 2015 in the Enersource RZ.

Lost Revenue Adjustment Mechanism for 2011-2014 and 2015-2020

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive to the OEB (the "Directive") to establish electricity and conservation and demand management targets to be met by licensed electricity distributors over a four year period commencing January 1, 2011. The Minister of Energy and Infrastructure included guidance to the OEB that lost revenues that result from CDM programs should not act as a disincentive to a distributor to promote CDM activities.

On April 26, 2012, in response to the Directive, the OEB issued a new set of *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets that are a condition of licence. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period.

The OEB authorized the establishment of an LRAM variance account ("LRAMVA") to record, at the customer rate-class level, the difference between:

(i) the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for CDM programs, and

(ii) the level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

The variance calculated from the comparison will result in a credit or a debit to the ratepayer at the customer class level in the LRAMVA.

On March 31, 2014, the Ministry of Energy and Infrastructure, in response to the Government of Ontario's Long-Term Energy Plan ("LTEP"), issued a directive to the OEB ("the Conservation Directive") to promote CDM, including amending the licences of electricity distributors and establishing CDM Requirement guidelines ("the 2015 CDM Guidelines").

On December 19, 2014, the OEB issued *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* (EB-2014-0278) ("2015 CDM Guidelines") which amended the electricity distribution licences of all electricity distributors to include a condition that requires the distributors to make CDM programs available to each customer segment in their service area and to report annual CDM results to the IESO. The Board also requires that electricity distributors work with natural gas distributors and the IESO in coordinating and integrating electricity conservation and natural gas demand side management programs. The 2015 CDM Guidelines also confirmed the continuation of the LRAM mechanism to compensate distributors for lost revenues resulting from CDM programs for the 2015 to 2020 period.

On May 19, 2016, the OEB issued an *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs,* on the calculation of the LRAMVA in respect of peak demand savings.

In this report, the OEB determined that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year. The OEB also indicated that peak demand savings from Demand Response ("DR") programs should generally not be included within the LRAMVA calculation.

LRAM Calculations

The OEB has identified that distributors can apply for disposition of the balance in the LRAMVA as part of their cost of service applications and may apply for disposition on an annual basis, as part of their IRM application, if the balance is deemed significant by the applicant. Alectra Utilities is requesting approval for recovery of lost revenues for the Enersource RZ of $1,773,859, including carrying charges, which is above the materiality threshold for the Enersource RZ. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $589,950.

Alectra Utilities has determined the LRAM amount in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines and its 2016 Updated Policy for the calculation of LRAMVA in respect of peak demand savings. Alectra Utilities has completed the 2018 LRAMVA work form for the Enersource RZ provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA work form is filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 20, 2017, and is provided in Attachment 42. Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Enersource RZ in its lost revenue calculation in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities provides the following information:

(i) Alectra Utilities has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount for the Enersource RZ; and

(ii) Alectra Utilities has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation for the Enersource RZ. The IESO's Final Annual Verified Results for 2016 is filed as Attachment 43.

(iii) The IESO reports results by program. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Alectra Utilities estimated the split by rate class, drawing on participant-specific information where available; and

(iv) Alectra Utilities has provided additional data in Tab 8. Street Lighting of the LRAMVA Model in support of the Street Lighting project savings. Demand savings for the retrofit streetlight project do not appear on the IESO's Final Verified Result Report, as the reduction to peak demand occurs outside the IESO's peak hours. Demand savings were calculated based on the difference between billed kW demand from Alectra Utilities' billing system in the Enersource RZ on the streetlight account compared to the billed kW based on the demand prior to the LED streetlight project.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2017. Alectra Utilities proposes to dispose of its 2017 LRAMVA balance for the Enersource RZ in a future rate proceeding. Alectra Utilities observes that the balance in Account 1568, LRAM Variance Account, as identified in Tab "3. Continuity Schedule" does not match the amount being requested for disposition due to the exclusion of the 2017 balances, as mentioned previously.

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2016 to December 31, 2016 for the Enersource RZ resulting from the following:

(i) 2011 to 2015 CDM persistence savings in 2016; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2016.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 138, below.

Table 138 – Distribution Volumetric Rates – Enersource RZ

Year	Residential	GS<50 kW	General Service 50 to 499 kW	General Service 500 to 4,999 kW	Large Use	Street Lighting
	kWh	kWh	kW	kW	kW	kW
2016	$0.0112	$0.0122	$4.3901	$2.2661	$2.8053	$11.0105

Alectra Utilities' Enersource RZ's LRAMVA threshold approved in Enersource's 2013 Cost of Service Application (EB-2012-0033) is used as the comparator against actual savings for the lost revenue calculation for 2016. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 139, below.

Table 139 – LRAMVA Thresholds – Enersource RZ

Year	LRAMVA Threshold	Residential	GS<50 KW	General Service 50 To 499 KW	General Service 500 To 4,999 KW	Large Use	Street Lighting
		kWh	kWh	kW	kW	kW	kW
2016	2013	35,842,920	39,519,293	19,284	16,135	15,417	61,001

Alectra Utilities has calculated carrying charges on the LRAM amounts for the Enersource RZ from January 1, 2016 to December 31, 2018 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $1,773,859, representing a principal balance of $1,713,929 and carrying charges of $59,930.

Alectra Utilities has provided a summary of its lost revenue calculations for the Enersource RZ by year for each rate class in Tables 140 and 141 below, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 140 – LRAMVA Totals by Rate Class – Enersource RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$211,531	$7,397	$218,928
GS<50 kW	kWh	$120,591	$4,217	$124,808
General Service 50 To 499 KW	kW	$1,089,322	$38,090	$1,127,412
General Service 500 To 4,999 KW	kW	$335,139	$11,719	$346,858
Large Use	kW	$108,392	$3,790	$112,182
Street Lighting	kW	-$151,047	-$5,282	-$156,329
Total		**$1,713,929**	**$59,930**	**$1,773,859**

Table 141 – LRAMVA by Year and Rate Class – Enersource RZ

Description	Residential	GS<50 kW	General Service 50 To	General Service 500	Large Use	Street Lighting	Total
	kWh	kWh	kW	kW	kW	kW	
2016 Actuals	$614,167	$602,727	$1,173,981	$371,703	$151,642	$520,604	$3,434,823
2016 Forecast	($402,635)	($482,135)	($84,659)	($36,564)	($43,249)	($671,652)	($1,720,894)
2016 LRAM Balance	**$211,531**	**$120,591**	**$1,089,322**	**$335,139**	**$108,392**	**($151,047)**	**$1,713,929**
Carrying Charges	**$7,397**	**$4,217**	**$38,090**	**$11,719**	**$3,790**	**($5,282)**	**$59,930**
Total LRAMVA Balance	**$218,928**	**$124,808**	**$1,127,412**	**$346,858**	**$112,182**	**($156,329)**	**$1,773,859**

The proposed rate riders that result from the disposition of Account 1568, LRAM Variance Account, is identified in Table 142 below and included in Tab “8. Calculation of Def-Var RR” in the IRM Model.

Table 142 – LRAMVA Rate Riders – Enersource RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential Service Classification	$0.00	$0.0002	kWh
General Service Less Than 50 kW Service Classification	$0.00	$0.0002	kWh
General Service 50 To 499 kW Service Classification	$0.00	$0.1951	kW
General Service 500 To 4,999 kW Service Classification	$0.00	$0.0752	kW
Large Use Service Classification	$0.00	$0.0640	kW
Street Lighting Service Classification	$0.00	($3.7908)	kW

TAX CHANGES

The OEB policy, as described in the Board'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 their OEB approved base rates. If applicable, these amounts will be refunded to customers over a 12-month period.

In this application, Alectra Utilities is not applying for a rate rider associated with the 50/50 sharing of the legislated tax change impact, as Alectra Utilities' corporate tax rate of 26.50% is not expected to change in 2019. Therefore, there is no shared tax savings in this application.

INCREMENTAL CAPITAL MODULE

Overview

Alectra Utilities filed a five year DSP for the Enersource RZ ("Enersource RZ DSP") for 2018 to 2022 in its 2018 EDR Application (EB-2017-0024). The Enersource RZ DSP identifies how Alectra Utilities plans, manages and develops the Enersource RZ distribution system and associated infrastructure, and how capital investments are determined while balancing customer rate impacts with system requirements. The capital investment plan in the DSP includes projects and programs that are designed to deliver the required functions at the appropriate level of service and financial performance. The outcome of Alectra Utilities' asset management practices in the Enersource RZ results from the balance of competing considerations (e.g. risk, performance, cost) in a sustainable fashion and the maximization of enterprise value, while satisfying applicable regulatory requirements and compliance obligations.

Alectra Utilities requested incremental capital funding for the Enersource RZ in its 2018 EDR Application (EB-2017-0024). In its Decision and Order, the OEB approved incremental funding for the Transformer Replacement Project and the York MS Substation Upgrade Project in the Enersource RZ.

Alectra Utilities is seeking Board approval for incremental capital funding for the Enersource RZ for 2019, through distribution rate riders as identified in Attachment 44. Alectra Utilities has capital investment needs for the Enersource RZ that are not funded through existing distribution rates. The needs fall into the system renewal category. As previously stated, the Enersource RZ is on Price Cap IR for the purpose of setting 2019 electricity distribution rates and, therefore, the ICM is available to the Enersource RZ and is incorporated as the relief sought in this application. The projects that form the ICM request for the Enersource RZ reflect significant, incremental, and discrete projects, as contemplated by the EDR Application Decision. Alectra Utilities provides justification for the request for incremental capital, below.

Alectra Utilities strives to ensure the safe and reliable distribution of electricity in its rate zones while accommodating new connections. In managing its distribution system, Alectra Utilities takes into account the underlying business risks, including operational, financial, environmental and safety impacts on the utility, its stakeholders or the broader public.

Since 2014, key reliability metrics for the Enersource RZ (e.g. SAIDI, SAIFI) have been trending upward, indicating an overall deterioration in reliability performance. Alectra Utilities is committed to addressing this upward trend and reducing the associated operational risks (in particular, adverse impact on the reliability and quality of distribution services provided to customers) as well as the resulting financial impact of increased system disturbances. Further, Alectra Utilities monitors and manages environmental and safety risks by continuing to enhance its asset inspection and testing practices, and to maintain or renew the assets known to pose risks to the environment or to public health and safety.

Once Alectra Utilities selects the projects needed to address the relevant business risks, it prioritizes and paces all investments to ensure that the overall portfolio is reasonable with respect to the anticipated resource requirements and rate changes.

In making asset management and capital planning decisions, Alectra Utilities leverages stakeholder engagement to align investment activities with customer value. By engaging customers, Alectra Utilities is better positioned to plan and assess capital expenditures relative to customer concerns and preferences. As indicated by engagement activities conducted last year, customers have shown their preference for Alectra Utilities to replace its distribution assets before failure to ensure that system performance and reliability are maintained.

The asset management objectives for the Enersource RZ include:

(i) Effectively managing operational, financial, environmental, safety and regulatory risks relating to Enersource RZ assets;
(ii) Adopting asset management practices that build understanding and accountability for stakeholder requirements and preferences;
(iii) Planning for adequate and suitable resources for work execution; and
(iv) Creating value by balancing competing considerations, including the overall costs and reliability performance associated with the Enersource RZ's distribution system assets.

In formulating the DSP and capital expenditures plan for the Enersource RZ, Alectra Utilities took into account the following business values, in alignment with the OEB's RRFE: (i) regulatory/public policy responsiveness; (ii) operational effectiveness; (iii) customer focus; and (iv) financial performance. In practice, Alectra Utilities prioritizes the investment proposals for the Enersource RZ based on their expected impact on these business values, which are more concretely understood in terms of the associated risks: operational; environmental; financial; and safety and regulatory.

A key project set out in the Enersource RZ DSP is the replacement of distribution transformers that are showing signs of oil leaks, as identified by Alectra Utilities through rigorous inspection efforts. In view of its regulatory obligations, Alectra Utilities aims to proactively replace these transformers before significant oil leaks and environmental liabilities materialize.

Through effective planning, Alectra Utilities ensures that funding is appropriately balanced and allocated for key initiatives within the Enersource RZ, including the mandatory System Access projects driven by public transit or road works, System Renewal projects to address degrading system performance, System Service projects to meet growing capacity requirements, as well as the ongoing management of General Plant assets. Moreover, by pacing and balancing investments, Alectra Utilities strives to ensure predictable and reasonable rate changes for customers.

Alectra Utilities provides a summary of its historical and proposed capital investments by category in Table 143 below. Amounts shown are net of contributed capital. The proposed capital investments ensure that Alectra Utilities is able to distribute electricity in the Enersource RZ in a safe and reliable manner, meet system load growth demands, and complete all regulatory driven initiatives. Each investment category is further discussed below. Alectra Utilities has filed at Attachment 48, details by project for the proposed 2019 capital spending plan.

Table 143 – Capital Expenditures by Category from 2014 to 2022 ($000s) – Enersource RZ

Category	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
System Access	$5,626	$12,253	$11,822	$6,617	$7,360	$13,754	$13,769	$12,709	$10,769
System Renewal	$31,244	$37,472	$35,196	$38,203	$35,323	$40,948	$34,601	$35,162	$35,738
System Service	$10,951	$56,776	$12,724	$9,966	$7,956	$13,407	$13,717	$13,522	$14,007
General Plant	$6,230	$9,546	$4,333	$4,652	$4,833	$6,206	$7,247	$8,020	$6,330
Total	**$54,051**	**$116,047**	**$64,075**	**$59,438**	**$55,472**	**$74,315**	**$69,334**	**$69,414**	**$66,844**

System Access

The key investment drivers for system access projects include third party requirements (e.g. plant relocation or upgrade to accommodate road widening or LRT) and Alectra Utilities' service obligations with respect to customer connection requests. The historical and forecast capital expenditures for system access projects are set out in Table 144, below.

Table 144 – System Access Capital Expenditures by Category from 2014 to 2022 ($000s) – Enersource RZ

Category	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Road Projects	$205	$8	$414	$315	$1,341	$2,393	$2,632	$2,392	$1,434
Light Rail Transit	$0	$0	$75	($75)	$403	$5,782	$5,533	$4,784	$3,486
New Subdivisions	$722	$4,225	$4,721	$2,190	$2,683	$2,293	$2,293	$2,292	$2,291
Industrial & Commercial Services	$2,017	$3,234	$2,663	$0	$0	$0	$0	$0	$0
Residential Service Upgrades	$0	$361	$517	$463	$0	$408	$408	$407	$407
Smart Metering Large Commercial	$414	$881	$764	$0	$0	$0	$0	$0	$0
Wholesale Metering	$52	$210	$636	$0	$0	$0	$0	$0	$0
Metering Equipment	$1,411	$1,410	$1,433	$3,474	$2,840	$2,809	$2,839	$2,783	$3,150
Smart Metering	$719	$1,687	$436	$0	$0	$0	$0	$0	$0
Green Energy - FIT/MicroFIT	$87	$238	$162	$251	$95	$70	$65	$50	$0
System Access	**$5,626**	**$12,253**	**$11,822**	**$6,617**	**$7,360**	**$13,754**	**$13,769**	**$12,709**	**$10,769**

System Renewal

The Enersource RZ's system renewal projects are mainly driven by the need to address assets that have reached the end of their useful life, and that are operating at heightened risk of failure or below required reliability levels.

Table 145 below presents the historical capital expenditures for system renewal investments for the Enersource RZ. Other than the subdivision renewal projects and transformer replacement project, the other renewal projects are expected to require steady funding over the forecast period that are generally in line with historical spending.

Table 145 – System Renewal Capital Expenditures by Category from 2014 to 2022 ($000s) – Enersource RZ

Category	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Subdivision Renewal Program	$9,307	$13,626	$11,389	$13,905	$12,579	$16,182	$17,774	$17,774	$17,778
Overhead Distribution Renewal and Sustainment	$5,051	$8,099	$8,344	$6,192	$8,666	$8,048	$6,755	$6,755	$6,929
Subtransmission Renewal	$0	$1	$2,170	$3,041	$0	$3,283	$3,436	$4,186	$4,786
Transformer Replacement	$12,623	$12,162	$8,519	$8,395	$9,297	$8,632	$1,831	$1,642	$1,438
Underground Distribution Renewal and Sustainment	$3,848	$3,258	$4,464	$6,306	$4,459	$4,484	$4,486	$4,486	$4,487
Emergency Replacement Program	$416	$325	$310	$365	$322	$319	$319	$319	$319
System Renewal	**$31,244**	**$37,472**	**$35,196**	**$38,203**	**$35,323**	**$40,948**	**$34,601**	**$35,162**	**$35,738**

An example of a system renewal project is the transformer replacement project. Alectra Utilities is replacing a large number of distribution transformers that show signs of oil leaks. This multi-year project is required to replace a backlog of transformers that were found to be leaking or contain Polychlorinated Biphenyl (“PCB”) oil in order to avoid expensive and hazardous environmental contamination and the need for subsequent remediation.

System Service

The key investment drivers for system service projects include capacity constraints (i.e. to accommodate planned or realized load at substations or distribution circuits), reliability considerations (i.e. to address poor performing areas with high frequency or duration of supply interruptions), and system efficiency and operability. The historical and forecast capital expenditures for system service projects are set out in Table 146, below.

Table 146 – System Service Capital Expenditures by Category from 2014 to 2022 ($000s) – Enersource RZ

Category	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Municipal Substation Construction & Upgrades	$5,850	$9,229	$7,843	$5,692	$4,166	$7,552	$7,702	$7,752	$7,962
Subtransmission Expansion	$3,237	$3,920	$1,934	$1,642	$1,620	$2,499	$2,499	$2,499	$2,499
Automation / SCADA	$1,863	$3,148	$2,947	$2,632	$2,170	$3,357	$3,517	$3,272	$3,547
Hydro One CCRA	$0	$40,479	$0	$0	$0	$0	$0	$0	$0
System Service	**$10,951**	**$56,776**	**$12,724**	**$9,966**	**$7,956**	**$13,407**	**$13,717**	**$13,522**	**$14,007**

General Plant

Key investment drivers for general plant projects relate to business requirements for fleet assets, major tools and equipment, IT systems, and grounds and buildings. The historical and forecast capital expenditures for general plant projects are set out in Table 147 below.

Table 147 – General Plant Capital Expenditures by Category from 2014 to 2022 ($000s) – Enersource RZ

Category	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022
Engineering & Asset Systems	$659	$802	$716	$1,055	$890	$899	$895	$944	$896
Rolling Stock	$926	$2,489	$1,582	$861	$1,842	$1,582	$1,810	$1,848	$1,749
Information Technology	$493	$1,026	$313	$1,217	$1,681	$2,028	$2,218	$2,654	$1,776
JDE / ERP System	$883	$1,632	$20	$0	$0	$0	$0	$0	$0
Meter to Cash	$686	$1,435	$436	$0	$0	$0	$0	$0	$0
Grounds & Buildings	$2,417	$1,910	$1,037	$1,255	$80	$1,363	$1,983	$2,231	$1,564
Acquisition of Administrative Building	$0	$0	$0	$0	$0	$0	$0	$0	$0
Major Tools	$167	$252	$230	$264	$340	$333	$340	$343	$345
General Plant	**$6,230**	**$9,546**	**$4,333**	**$4,652**	**$4,833**	**$6,206**	**$7,247**	**$8,020**	**$6,330**

Customer Consultation

As discussed previously, Alectra Utilities engaged Innovative to solicit feedback from customers on proposed incremental capital funding for the Enersource RZ. The Innovative Report is provided as Attachment 49. As set out there, a telephone survey was conducted using stratified random samples for Residential and General Service Customers and an online survey was also deployed for Large Use Customer. This approach allowed Alectra Utilities to capture customers' views on the emerging needs or shifting priorities and to generate feedback on the specific projects being considered for this application. The engagement shows that almost all customer groups support the ICM projects reflected in the application at the investment levels proposed or even higher.

The top two priorities for Alectra Utilities' customers in both the Enersource and PowerStream rate zones are: delivering reasonable distribution rates; and ensuring reliable electrical service. The engagement confirms that the vast majority of customers are satisfied with the current level of reliability they experience, and expect Alectra Utilities to do what is necessary to maintain it. In principle, most customers support some form of investment program that ensures a consistently reliable and modern distribution system, which also addresses growth and system demands. Customers also expressed frustration in relation to their electricity bills; Alectra

Utilities is well aware of this customer sentiment. When asked how Alectra Utilities can improve service, most common responses throughout the engagement were either "nothing" or "lower rates".

Overall, customer groups in the Enersource RZ supported the investment levels and pacing proposed by Alectra Utilities, or even higher.

In conducting customer engagement, Alectra Utilities determined the maximum eligible capital it could apply for in the Enersource RZ, based on its most recent 2019 capital forecast of $74,315,118, before incorporating customer preferences, and its materiality threshold of $35,351,495. The computation of the materiality threshold is discussed in further detail below. The difference between the 2019 capital forecast, before incorporating customer preferences, and the materiality threshold was $38,783,623 as identified in Table 148, below.

Table 148 – Eligible Incremental Capital for Customer Consultation – Enersource RZ

Eligible Incremental Capital	Capital Expenditures $
2019 Capital Forecast	$74,315,118
Less: Materiality Threshold	$35,531,495
Maximum Eligible Incremental Capital	**$38,783,623**

Alectra Utilities identified two discrete and material capital projects for presentation to customers which totalled approximately $9.4MM for the Enersource RZ. These projects are identified in Table 149 below and do not include projects related to General Plant for which Alectra Utilities is not seeking incremental capital funding.

Table 149 – Eligible Capital Projects for Customer Consultation – Enersource RZ

Project Description	Capital Expenditures
Leaking Transformer Replacement Project	$7,500,000
Rometown	$1,850,000
System Renewal	**$9,350,000**
Total Enersource RZ Incremental Capital Funding	**$9,350,000**

As identified in the Innovative Report, customers were presented with the 2019 bill impacts related to the implementation of the projects listed in Table 149, above. They were also presented with the total bill impact over the deferred rebasing period. These are identified in Table 150, below. The calculation of the rate riders associated with the proposed ICM is provided in Attachment 44. Large Use customers were presented with individual bill impacts based on historical usage.

Table 150 – Bill Impacts for Incremental Capital Presented to Customers – Enersource RZ

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	GS<50 (2000 kWh)	GS>50
System Renewal	$9.4	$0.15	$0.48	$7.72
Total	**$9.4**	**$0.15**	**$0.48**	**$7.72**

The ICM questions varied according to the specific projects being considered in each rate zone. In the Enersource RZ respondents were asked about two ICM renewal projects; Transformer Replacement – which is a continuation of a project approved by the OEB in the EDR Application Decision, and the Rometown area overhead system. In each, respondents were given a short introduction of the issue and asked to choose between the alternative approaches available. In each case, the options tied costs to potential benefits.

Alectra Utilities' customers in the Enersource RZ are divided on the transformer replacement project. Majorities in the residential and GS<50kW respondent groups prefer to pay more to replace the leaky transformers now. GS>50kW customers and Large Use customers prefer to stick with replacement within the current renewal plan.

For the Rometown project, all customer groups in the Enersource RZ prefer to at least replace the 78 most pressing poles now and large proportions would like to replace all the poles now or replace the existing above ground system with an underground one, even though the cost of these options is higher.

Table 151 summarizes customer preferences between the options for the two ICM projects.

Table 151 – ICM Project Feedback Enersource RZ

Leaky Transformer	Residential	Small Business	Mid-Market	Large Use
Replace Leaking Transformer	58%	52%	40%	3 of 9
Existing Renewal Plan	38%	42%	58%	6 of 9
Don't know	3%	6%	3%	n/a
Rometown Overhead	Residential	Small Business	Mid-Market	Large Use
Replace Reactively	19%	29%	23%	2 of 9
Partial Replacement	17%	19%	26%	2 of 9
Full Replacement	28%	18%	28%	3 of 9
Replace with Underground System	38%	26%	20%	1 of 9
Don't know	8%	8%	4%	1 of 9

Table 152 summarizes customer feedback on the reasonability of the proposed rate increase

Table 152 – Customers' View on ICM Bill Impacts for the Enersource RZ

Opinion of Proposed Plan	Residential	Small Business	Mid-Market	Large Use
The proposed rate increase is reasonable	72%	60%	56%	7 of 9
The proposed rate increase is unreasonable	25%	33%	42%	n/a
Don't know	3%	6%	2%	2 of 9

Alectra Utilities initially contemplated that it would undertake only a partial replacement of the Rometown overhead system. However, based on feedback from customers above, and as provided in the Innovative Report, Alectra Utilities has determined that it will proceed with the full replacement of poles in the Rometown project at a cost of $3.2MM.

Note, in this respect, while Alectra Utilities had asked for customers' views of the ICM bill impact assuming only a partial replacement, given the level of support for a full replacement (even with the higher total cost set out for customers), strong indication that the initially proposed rate increase was reasonable and the relatively modest difference in bill impact between the two options ($0.02/month for residential customers), Alectra Utiltiies believes that the results set out in Table 152 would not be significantly different had customers been asked to comment on the total bill impact assuming full replacement.

Alectra Utilities has updated its ICM project listing based on customer preferences for the Enersource RZ; and its ICM request from $9.4MM to $10.7MM in capital expenditures.

Alectra Utilities provides the eligibility criteria for its capital funding request below.

Eligibility for Incremental Capital

In order to be eligible for incremental capital, an Incremental Capital Module (“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 *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) issued on September 18, 2014 (“the ACM Report”).

These criteria are discussed in detail below.

The OEB’s Capital Module Applicable to ACM and ICM (“ICM Module”) for the Enersource RZ is attached as Attachment 44.

<u>Materiality</u>

Materiality Threshold Test

The Board states in the ACM Report that “a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-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”

The Board-defined materiality threshold is represented by the following formula:

$$\textbf{\textit{Threshold Value}}\,(\%) = 1 + [(\frac{RB}{d}) \times (g + PCI \times (1 + g))]) \times ((1 + g) \times (1+ PCI)^{n-} + 10\%$$

RB = rate base from the distributor’s last cost of service

d = depreciation from the distributor’s last cost of service

g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application

PCI = Price Cap Index (IPI-stretch_factor) from the distributor’s most recent Price Cap IR application as a placeholder for the initial application filing to be updated when new information becomes available

n = number of years since the last rebasing

The materiality threshold has been calculated for the Enersource RZ using the Board-approved rate base and depreciation amounts from its 2013 Cost of Service Application (EB-2012-0033), a price cap index (PCI) of 0.9% and a growth rate of (0.27%).

The PCI of 0.9% is a placeholder to be updated with the OEB's approved PCI for 2019 when it is available. It is based on inflation of 1.20% less a productivity factor of 0.00% and a stretch factor of 0.30% as identified in Table 153 below.

The growth rate of (0.27%) has been calculated in accordance with the ACM Report and is equal to the decrease in revenue based on Enersource's 2013 OEB approved billing determinants divided by Enersource's 2017 actual billing determinants, using 2017 approved rates. The growth rate calculation is identified in Table 153 below.

Table 153 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula approved in the ACM Report. The threshold value for 2019 is 124% which results in a threshold capital expenditure value of $35,531,495.

Table 153 – Threshold Capital Expenditure Calculation – Enersource RZ

Description	Amount
Inflation	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	0.90%
2017 Volumes @ 2017 Rates	$128,973,917
2013 Volumes @ 2017 Rates	$130,394,229
Growth Factor	-0.27%
Year	2,019
# Years since rebasing	6
Price Cap Index	0.90%
Growth Factor	-0.27%
Dead Band	10%
Rate Base	$610,456,833
Depreciation	$28,721,695
Threshold Value % - 2019	124%
Threshold Capital Expenditure $ - 2019	**$35,531,495**

Eligible Capital Amount

Table 154 below compares the 2019 capital forecast for the Enersource RZ to the Threshold Capital Expenditure to calculate the maximum eligible incremental capital of $38,783,623 for the Enersource RZ.

Table 154 – Maximum Eligible Incremental Capital – Enersource RZ

Eligible Incremental Capital	Capital Expenditures $
2019 Capital Forecast	$74,315,118
Less: Materiality Threshold	$35,531,495
Maximum Eligible Incremental Capital	**$38,783,623**

Table 155 below identifies the eligible capital projects for which the Enersource RZ is seeking approval, after adjustments for customer preferences, discussed above. Only projects that are discrete and material have been included. These projects are discussed in detail in Attachment 46. There are no customer contributions associated with the two ICM projects in the Enersource RZ.

Table 155 – 2019 Eligible Capital Projects by Category – Enersource RZ

Project Description	Capital Expenditures
Leaking Transformer Replacement Project	$7,500,000
Rometown	$3,200,000
System Renewal	**$10,700,000**
Total Enersource RZ Incremental Capital Funding	**$10,700,000**

<u>Need</u>

Means Test

In addition to the materiality criteria, a distributor must pass the Means Test (as defined in the ACM Report) in order to qualify for funding through an ICM in an Incentive Rate Setting term.

If a distributor's regulated return, as calculated in its most recent calculation (Reporting and Record Keeping Requirements ("RRR") 2.1.5.6), exceeds 300 basis points above the deemed return on equity ("ROE") embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.

Alectra Utilities filed its first annual Reporting and Record Keeping Requirements ("RRRs") post consolidation on April 30, 2018. RRR data for all measures were filed for Alectra Utilities, and not individually, by rate zone. Alectra Utilities 2017 ROE was calculated to be 8.43%, 47 basis points below a calculated ROE for Alectra of 8.90%. Alectra Utilities calculated a consolidated deemed ROE percentage using the weighted average of the OEB-approved rate base amounts for each rate zone, from the most recent OEB-approved rebasing application for each of the predecessor companies. Therefore Alectra Utilities meets the Means Test. Alectra Utilities ROE calculation for 2017, filed in RRR 2.1.5.6, is filed as Attachment 45.

Discrete and Material Projects

As identified on page 17 of the ACM report, amounts must be based on discrete projects, and should be directly related to the claimed driver.

Each eligible capital project is a discrete project that meets or exceeds the materiality level for the Enersource RZ. These projects are significant, relative to Alectra Utilities' overall capital expenditure and are not funded through existing rates**.** Each project is distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning process as required in 2019. Alectra Utilities overall 2019 capital budget for all rate zones is $257.3MM.

Further information with respect to the driver of each project is provided in each business case in Attachment 46.

<u>Prudence</u>

The eligible capital projects for which Alectra Utilities is seeking approval for the Enersource RZ represent the most cost effective option for ratepayers. Analysis of options is provided in the business case for each eligible capital project in Attachment 46.

A description of each of the projects' need and prudence can be found in the business case summaries set out immediately below. The project-related business cases can be found at Attachment 46.

Project/ Budget/ In-Service Date ("ISD")	**Project Need and Description**
Rometown Area Overhead System Rebuild (see System Renewal Project Business Case 2019-C0561) Budget: $3.2MM Forecast ISD: Q4/2019	**<u>Rometown Area Overhead System Rebuild</u>** **<u>System Renewal: $3.2 MM</u>** <u>Project Description and Drivers</u> • Through an enhanced rogram in Mississauga Alectra Utilities identified a number of overhead system areas that are deteriorated (i.e. poles with signs of rotting, mechanical damaged on equipment, insect infectation, and cracking), substandard and in need of renewal). Based on these inspections, and resistograph testing of wood poles' residual strength, the area south of Queen Elizabeth Way and east of Dixie Road was identified in need of renewal investment given the poor conditions of overhead assets, existence of leaning poles, identified porcelain insulators (which are prone to cracking and deterioration leading to failures and pole fires), and transformers showing signs of oil leaks. • In contrast to the 2019 Pole Replacement Program, this project targets a defined system area with known substandard assets, based on identified system renewal needs. Where the Pole Replacement Program replaces individual poles throughout the RZ, based on identified hazards and poor condition, the Rometown project replaces the existing substandard overhead system and brings it to present day standards. • Considering results from field inspection, asset health index assessment and awareness of sub-standard system configurations, Alectra applied an overlay methodology for overhead renewal. The overlay method examined specific system areas with assets of sub-standard condition which are then used to identify and prioritize areas with renewal investment needs. Areas with high concentration of multiple sub-standard findings, system configuration and loading demands as well as business values are used to prioritize investment needs for overhead system renewal. <u>Project Options</u> • The scope of the project is to renew the deteriorated overhead system to present day standard configuration and increase the distribution system's

	longevity. As per 2016 Asset Condition Assessment ("ACA") study, 34.3% (68 out of 198) poles in this area were flagged "Poor" and 28.3% (56 out of 198) poles "Fair" based on parameters of pole physical condition, mechanical damage, pole leaning and cracks. In the May 2018 Customer Engagement, Alectra customers in the Enersource Rate Zone provided their preferences for the Overhead Rometown Rebuild Project. The customer engagement results indicate that all Alectra customer groups in the Enersource Rate Zone preferred to at least complete the partial replacement of the system, and a large portion would like to replace all of the system now, or replace the overhead system with an underground one. • The proposed solution is to renew the entire overhead system in the area complete with new concrete and wood poles, framing, insulators, and replacement of pole-mounted transformers. This option would minimize the piecemeal and ad-hoc equipment replacements during outages under reactive maintenance work. The total cost of this option is estimated at $3.2MM. • Alectra considered the replacement of only the problematic conditions in the overhead system. This option included the replacement of only poor-condition poles and leaking transformers, as well as tree trimming. This option has lower near term costs but maintenance, inspection and long term replacement costs will be higher in the long run. The estimated cost of the partial overhead renewal in Rometown is $1.85MM. • Alectra also examined the option of replacing the overhead system with underground feeders. The benefit of undergrounding an overhead system includes protection from elements such as weather related events, animal contacts and collisions from vehicles. However, the option to underground the distribution system was estimated to cost between $12MM and 18MM and was determined to be uneconomical relative to other options. • Without the required investment, the distribution system in this area would continue to be exposed to risks of worker and public safety concerns due to poles in poor condition, and the risk of potential environmental contamination due to transformer oil leaks will also persist. • Results from Customer Engagement indicate more than half of Residential and Small Business customers and almost half of the Mid-market customers and Large Users prefer to replace all 198 poles now or replace with an underground system.

Replacement of Leaking Transformers

(see System Renewal Project Business Case 2019-C0563)

Budget:

$7.50MM

Forecast ISD: Q4/2019

Replacement of Leaking Transformers

System Renewal: $7.50MM

Project Description and Drivers

- Capital investment is required in 2019 to complete a multi-year project to replace a backlog of transformers that were found to be leaking or containing PCB oil. This project is a continuation of a project approved by the OEB for funding in its decision on Alectra Utilities' 2018 Electricity Distribution Rate Application and Incremental Capital Module ("ICM") Application (EB-2017-0024).
- From 2013 to 2017, Enersource replaced 2,680 transformers that were identified to be leaking oil or containing PCBs. At 103 transformer locations where oil spills occurred, environmental remediation was required and immediately completed as per applicable environmental regulations. Over the four year period from 2013 to 2016, Enersource approximately $5.6MM was spent on environmental remediation due to oil leaked from transformers.
- As of January 1st 2018, the backlog of remaining identified leaking transformers and transformers containing PCB oil is 1,221 transformers. Alectra has determined that transformer oil spills pose a significant environmental risk to the public which has driven the investment need to replace transformer leaking or indicate leaking oil into the environment. In order to address this investment need, Alectra has developed a multi-year project to replace the remaining backlog of identified leaking and transformers containing PCB oil. A breakdown of transformers to be addressed through this project is shown below.

Transformer Type	PCB Transformers Indicating Leaking Oil	Non-Leaking Transformers with PCB Oil	Transformers (Non-PCB) Indicating Signs of Leaking	Total
Single-Phase Pad Mount	6	45	410	**461**
Three-Phase Pad Mount	1	2	44	**47**
Vault Transformers	0	31	202	**233**
Pole Mount Transformers	0	7	473	**480**
Total	**7**	**85**	**1,129**	**1,221**

Project Description

	• Alectra has developed a multi-year project to address the remaining 1,221 leaking transformers and transformers containing PCB oil to minimize safety, environmental, financial and regulatory risks. Failure to replace these transformers in a timely manner will pose a considerable risk to the environment, the public and to Alectra should the identified transformers not be addressed and require environmental remediation. • As the proposed solution, the replacement project is preferable to the other options assessed (i.e., to continue to run distribution transformers to failure), because it would immediately address the safety, environmental, reliability, financial and regulatory risks identified above, and would avoid disruptive and costly environmental clean-ups. • Alectra plans to complete the replacement of transformers identified through inspections to be leaking oil or transformers containing PCB oil in 2019 based on a prioritized and paced manner to address the backlog. • The transformer replacement project investment has paced the annual investment with an annual expenditure of $8.4MM in 2018 and $7.5MM in 2019. The multi-year replacement project is scheduled to be completed in 2019.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $9,350,000 is $774,525. Table 156 below summarizes the incremental revenue requirement for the eligible projects.

Table 156 – Incremental Revenue Requirement – Enersource RZ

Incremental Revenue Requirement	Amount
Return on Rate base - Total	$677,840
Amortization	$280,671
Incremental Grossed Up PILs	($73,165)
Total	**$885,346**

The Rate of Return has been calculated using the cost of capital parameters approved by the Board in Enersource's 2013 Cost of Service application.

Project costs have been assigned to the property plant and equipment accounts as defined in the Accounting Procedures Handbook effective January 1, 2012. Amortization has been calculated on a straight-line basis over the useful life of each asset as defined in the Accounting Procedures Handbook. The useful lives are consistent with those filed in Enersource's 2013 Cost of Service application (EB-2012-0033) and is summarized in Table 157, below.

A full year of depreciation has been recovered which is consistent with the OEB's policy in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219), issued September 18, 2014. Similarly, PILs have been calculated using a full year of Capital Cost Allowance ("CCA").

The detailed calculation of incremental revenue requirement by project is provided in the Board's Capital Module Applicable to ACM and ICM ("Capital Module") filed as Attachment 45.

Alectra Utilities also provides the calculation of the revenue requirement for each of the proposed incremental capital projects (Attachment 47), as follows:

Table 157 – Incremental Revenue Requirement by ICM Project – Enersource RZ

Project Description	Return on Rate base	Amortization	Incremental Grossed Up PILs	Total Revenue Requirement
Leaking Transformer Replacement Project	$475,007	$198,490	($50,676)	$622,821
Rometown	$202,833	$82,181	($22,489)	$262,524
System Renewal				**$885,346**
Total Incremental Revenue Requirement	**$677,839.87**	**$280,671.00**	**($73,165.09)**	**$885,346**

Rate Riders

Alectra Utilities is seeking Board approval for the ICM rate riders, for the Enersource RZ identified in Table 158 to recover the revenue requirement of $885,346 identified in Table 157 above. The revenue requirement has been allocated to rate classes based on the current allocation of revenue using Tab 8. Revenue Proportions of the ICM Model filed as Attachment 44. The revenue requirement for the residential class will be recovered via a fixed rate rider as directed by the OEB in the Chapter 3 Filing Requirements. Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in the ICM Model Sheets 8 and 12.

Table 158 - Incremental Capital Funding Rate Riders – Enersource RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.16	$0.0000	kWh
General Service under 50 kW	$0.30	$0.0001	kWh
General Service 50 to 499 kW	$0.53	$0.0317	kW
General Service 500 to 4999 kW	$11.99	$0.0163	kW
Large Use	$94.56	$0.0202	kW
Unmetered	$0.06	$0.0001	kWh
Street Lighting	$0.01	$0.0792	kW

Bill Impacts - ICM Rate Riders

Table 159 below identifies the bill impacts by rate class as a result of the addition of the 2018 incremental capital funding rate riders. Bill impacts as compared to the total bill including HST range from 0.04% for the Large Use classes to 0.4% for Street Lighting.

Table 159 – ICM Bill Impacts (Total Bill) – Enersource RZ

Rate Class	Unit	kWh	kW	ICM Rate Rider Incl HST	% Increase vs. Total Bill
Residential	kWh	750		$ 0.17	0.15%
General Service under 50 kW	kWh	2,000		$ 0.53	0.17%
General Service 50 to 499 kW	kW	100,000	230	$ 8.84	0.05%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 54.99	0.07%
Large Use	kW	3,000,000	5,000	$ 220.98	0.05%
Unmetered	kWh	300		$ 0.10	0.20%
Street Lighting	kW	33	0.1	$ 0.02	0.46%

SUMMARY OF BILL IMPACTS

A summary of bill impacts for the typical customer by rate class is presented in Tables 160 to 162 below. Attachment 37 provides a detailed summary of the bill impacts for each customer class for 2019.

Table 160 – Distribution Bill Impacts by Rate Class – Enersource RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.15)	(0.58)%
GS<50	kWh	2,000	$ 0.53	0.72%
GS 50-499 kW	kW	230	$ 49.19	3.80%
GS 500-4,999 kW	kW	2,250	$ 197.51	2.56%
Large User	kW	5,000	$ 234.64	0.77%
Street Lighting	kW	-	$ (0.37)	67.17%

Table excludes the impact of HST (13%) & Provinicial Rebate (8%)

Table 161 – Distribution Bill and Rate Rider Impacts by Rate Class – Enersource RZ

Distribution Bill and All Rate Rider Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.44)	(1.60)%
GS<50	kWh	2,000	$ (0.25)	(0.32)%
GS 50-499 kW	kW	230	$ 189.93	15.81%
GS 500-4,999 kW	kW	2,250	$ 517.47	7.46%
Large User	kW	5,000	$ (815.36)	(2.83)%
Unmetered Scattered Load	kWh	0	$ (0.12)	(0.77)%
Street Lighting	kW	-	$ (0.33)	70.19%

Table excludes the impact of HST (13%) & Provinicial Rebate (8%)

Table 162 – Total Bill Impacts by Rate Class (before HST) – Enersource RZ

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2019 vs. 2018	
			$	%
Residential	kWh	750	$ (0.36)	(0.35)%
GS<50	kWh	2,000	$ (14.05)	(4.81)%
GS 50-499 kW	kW	230	$ (497.37)	(3.49)%
GS 500-4,999 kW	kW	2,250	$ (2,161.26)	(3.28)%
Large User	kW	5,000	$ (21,527.86)	(5.32)%
Unmetered Scattered Load	kWh	0	$ (2.19)	(4.61)%
Street Lighting	kW	-	$ (0.56)	(15.06)%

Table excludes the impact of HST (13%) & Provinicial Rebate (8%)

CONCLUSION

Alectra Utilities respectfully requests that the Board approve the relief sought for the Enersource RZ in this Application.