alectra utilities
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July 7, 2017

VIA 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-2017-0024

Alectra Utilities Corporation ("Alectra Utilities") submits its first electricity distribution rate application ("EDR") for all four rate zones, for approval of proposed distribution rates and other charges, effective January 1, 2018, as follows:

- Horizon Utilities Rate Zone ("Horizon Utilities RZ"), formerly Horizon Utilities Corporation, Custom Incentive Regulation ("IR") Year 4 Update;
- Brampton Rate Zone ("Brampton RZ"), formerly Hydro One Brampton Networks Inc., Price Cap IR and Incremental Capital Module ("ICM");
- 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.

In October 2012, the OEB released the *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors – A Performance-Based Approach* ("RRFE"). The OEB indicated, through the RRFE, that distributors would be required to file Distribution System Plans ("DSP") every five years. All rate zones but Enersource have OEB-reviewed DSPs. Accordingly, Alectra Utilities is filing a DSP for the Enersource RZ for 2018-2022. The DSP follows the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 Consolidated Distribution System Plans Filing Requirements* issued March 28, 2013.

Further, 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 14, 2016 (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 2016, prior to the consolidation of Enersource, Horizon Utilities, Hydro One Brampton and PowerStream. 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, 2015 for the Horizon Utilities, PowerStream and Enersource Rate Zones. Hydro One Brampton disposed of the balances in its LRAMVA as of December 31, 2015, as part of its 2017 IRM application (EB 2016-0080). Alectra Utilities is not seeking an LRAMVA disposition for the Brampton Rate Zone in this application.

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

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 2018 EDR Applications were not yet available. Alectra Utilities has used the 2017 OEB models for creating the models on which this application is based. Alectra Utilities has confirmed the accuracy of the billing determinants to the 2016 RRR, section 2.1.5.4, for each rate zone.

To assist the OEB, Alectra Utilities has created a Table of Concordance for the application and for the Distribution System Plan; 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

cc. Crawford Smith, Torys LLP
Charles Keizer, Torys LLP

EB-2017-0024

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, 2018

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ALECTRA UTILITIES CORPORATION

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

FILED: July 7, 2017

Applicant

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

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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, 2017 Horizon Utilities RZ
Attachment 2	Proposed Tariff of Rates and Charges January 1, 2018 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	Cost Allocation Model Horizon Utilities RZ
Attachment 8	Summary of Fixed/Variable Splits Horizon Utilities RZ
Attachment 9	RTSR Work Form Horizon Utilities RZ
Attachment 10	ESM Rate Rider Model Horizon Utilities RZ
Attachment 11	Lost Revenue Adjustment Mechanism Variance Account Work Form Horizon Utilities RZ
Attachment 12	2011-2014 Final IESO Results Report Horizon Utilities RZ
Attachment 13	2015 Final IESO Results Report Horizon Utilities RZ

BRAMPTON RATE ZONE

Attachment 14	Current Tariff of Rates and Charges January 1, 2017 Brampton RZ
Attachment 15	Proposed Tariff of Rates and Charges January 1, 2018 Brampton RZ
Attachment 16	Customer Bill Impacts Brampton RZ
Attachment 17	IRM Model Brampton RZ
Attachment 18	Incremental Capital Module Brampton RZ
Attachment 19	2016 ROE (RRR 2.1.5.6) Brampton RZ
Attachment 20	Pleasant TS CCRA (Agreement) Brampton RZ
Attachment 21	ICM Business Cases Brampton RZ
Attachment 22	2018 Capital spending by project Brampton RZ

POWERSTREAM RATE ZONE

ENERSOURCE RATE ZONE

CERTIFICATION OF THE EVIDENCE

As Chief Financial 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 14, 2016 and *Chapter Five of the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications* issued on March 28, 2013.

John G. Basilio, CPA, CA
Chief Financial Officer

Alectra Utilities Corporation
2018 Rate Application (EB-2017-0024)
Table of Concordance

			Rate Zones ("RZ")			
			Horizon Utilities	**Brampton**	**PowerStream**	**Enersource**
	Executive Summary		Exhibit 1, Tab 1, Schedule 1			
	Certification of the Evidence		Following the Table of Contents			
3.1.3	**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 1, 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 26	Ex 3, Tab 1, Schedule 1, Attachment 39
	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 18	Exhibit 3, Tab 1, Schedule 1, Attachment 31	Ex 3, Tab 1, Schedule 1, Attachment 45
	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 7			
	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 9			
	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 10			
	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 11		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, Attachment 1	Exhibit 3, Tab 1, Schedule 1, Attachment 14	Exhibit 3, Tab 1, Schedule 1, Attachment 23	Exhibit 3, Tab 1, Schedule 1, Attachment 36
5	Supporting documentation cited within the application (e.g. excerpts of relevant past decisions and/or settlement agreements)		Embedded 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	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
8	A text-searchable Adobe PDF format for all documents		Confirmed			
3.2.1	**Annual Adjustment Mechanism**					
1	Distributors shall use the 2017 rate-setting parameters as a placeholder until the stretch factor assignment and inflation factor for 2018 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 - Exhibit 2, Tab 1, Schedule 6, Table 30 LRAM - Exhibit 2, Tab 1, Schedule 6, Table 44	ICM - Exhibit 2, Tab 2, Schedule 10, Table 68	LRAM - Exhibit 2, Tab 3, Schedule 9, Table 90 ICM - Exhibit 2, Tab 3, Schedule 10, Table 106	LRAM - Exhibit 2, Tab 4, Schedule 9, Table 128 ICM - Exhibit 2, Tab 4, Schedule 11, Table 147
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 32	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.1	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.5	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

	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	N/A	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	N/A	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, Attach 11 and live model	N/A	Exhibit 3, Tab 1, Schedule 1, Attachment 28 and live model	Exhibit 3, Tab 1, Schedule 1, Attachment 42 and live model
4	A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount		Exhibit 2, Tab 1, Schedule 9	N/A	Exhibit 2, Tab 3, Schedule 9	Ex 2, Tab 4, Schedule 9
5	A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation and include a copy of this report		Exhibit 2, Tab 1, Schedule 9	N/A	Exhibit 2, Tab 3, Schedule 9	Ex 2, Tab 4, Schedule 9
6	For OEB-approved programs, 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		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	Exhibit 2, Tab 2, Schedule 10	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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
5	Details by project for the proposed capital spending plan for the expected in-service year		N/A	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
6	A description of the proposed capital projects and expected in-service dates		N/A	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
9	A description of the actions the distributor would take in the event that the OEB does not approve the application.		N/A	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
	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	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
13	A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the forecasted 2016 total capital expenditures and the ACM/ICM materiality threshold		N/A	Exhibit, 2, Tab 2, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 18, 19, 21, 22, 51	Exhibit 2, Tab 3, Schedule 10 and Exhibit 3, Tab 1, Schedule 1, Attachments 31, 32, 3, 34, 35, 51	Exhibit 2, Tab 4, Schedule 11 and Exhibit 3, Tab 1, Schedule 1, Attachments 45, 46,47, 48, 49, 50, 51
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 7	Exhibit 2, Tab 3, Schedule 8	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	N/A	Exhibit 2, Tab 4, Schedule 5, p.9

	Alectra Utilities Corporation	
	Distribution System Plan	
		Enersource
5.1.1	A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories: system access, system renewal, system service, general plant	Done
5.1.3	All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications	Done
5.2.1	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	DSP - s. 1.1
5.2.2	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter	DSP - s. 1.2, App. 'B' & 'C'
5.2.3	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	DSP - s. 1.3
5.3.1	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments - Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	DSP - s. 2.1
5.3.2	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	DSP - s. 2.2
5.3.3	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	DSP - ss. 2.3 & 2.4; App. 'D'
5.4.1	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	DSP - s. 3.1
5.4.2	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritize REG investments	DSP - s. 3.2
5.4.3	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	DSP - s. 3.3

5.4.4	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum)	DSP - s. 3.4
5.4.5 (1)	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	DSP - s. 3.5.1
5.4.5 (2)	Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	DSP - s. 3.5.2; Appendix E

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 (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 2018 electricity distribution rates. The ICM is available to these rate zones, as provided below.

At the time of this filing, 2018 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 third adjustment in the 2015-2019 Custom IR rate plan term.

Alectra Utilities also applies for incremental capital funding for the Brampton, 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 14, 2016 ("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.

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 2016, prior to the consolidation of Enersource, Horizon Utilities, Hydro One Brampton and PowerStream. Alectra Utilities seeks rate zone-specific tariffs.

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.

[1] EB-2016-0025 pg. 31

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, 2015 for the Horizon Utilities, PowerStream and Enersource RZs. The former Hydro One Brampton disposed of the balances in its LRAMVA as of December 31, 2015, as part of its 2017 IRM application (EB 2016-0080). Alectra Utilities is not seeking an LRAMVA disposition for the Brampton RZ in this application.

In 2016, Horizon Utilities, Hydro One Brampton, PowerStream and Enersource commenced tracking costs in the variance account "1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance", which was established by the OEB to record the difference between OEB cost assessments built into rates, and cost assessments that result from the application of the OEB's new cost assessment model, effective April 1, 2016. The OEB provided direction to record costs in this variance account in its letter "*Revisions to the Ontario Energy Board Cost Assessment Model*", dated February 9, 2016. Alectra Utilities will request disposition of the account balance in future rate proceedings, in accordance with the Board's policy on disposition of Group 2 accounts.

Accordingly, Alectra Utilities submits its first 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 4 Update;
- Brampton Rate Zone ("Brampton RZ"), formerly Hydro One Brampton Networks Inc., Price Cap IR and ICM;
- 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, 2018.

Enersource RZ DSP

In October 2012, the OEB released the *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors – A Performance-Based Approach* ("RRFE"). The OEB indicated, through the RRFE, that distributors would be required to file Distribution System Plans ("DSP") every five years. All rate zones but Enersource have OEB-reviewed DSPs. Accordingly, Alectra Utilities is filing a DSP for the Enersource RZ for 2018-2022.[2]

The Enersource Rate Zone 2018-2022 DSP ("Enersource RZ DSP") outlines Alectra Utilities' strategy of taking a complete life cycle approach to the management of its Enersource RZ assets. The Enersource RZ DSP follows the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 Consolidated Distribution System Plans Filing Requirements* issued March 28, 2013 ("Chapter 5 Filing Requirements") and the RRFE, in taking a robust approach to asset management that prioritizes and paces investments in a manner that aligns the interests of customers and Alectra Utilities.

The Enersource RZ DSP details how the Company 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 as explained 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.

[2] In the Oral Hearing for the MAADs Application, Alectra Utilities' witnesses testified that a consolidated DSP would be filed by April 2019. This DSP will, once filed and reviewed by the OEB, effectively update and replace the Enersource 2018-2022 DSP.

Vanry Associates ("Vanry") was retained to undertake an independent, third party review of the process and methodology used to develop the Enersource RZ DSP. This review involved careful consideration of Alectra Utilities' asset management practices in the Enersource RZ, to understand the linkages between the inputs that drive investment needs, the processes used to prioritize and pace investments and specific performance outcomes. In Vanry's professional opinion, the Enersource RZ DSP "represents a well-reasoned, fact based assessment of the needs of the system" and "that it reflects the desires of customers and the concerns of relevant stakeholders and the desires of customers…It is evident that the customer engagement results have influenced the focus of the DSP as well as the associated investment planning.[3]"

As Vanry further concludes in its review of the Enersource RZ DSP:

> *"The proposed investment plans align with what we see as being needed by the system to deliver the required performance levels and to meet the regulatory requirements. The pacing of the investments appears reasonable and reflective of a need to balance between costs and performance obligations and risks. The quality and calibre of the report, and the work that underpins it, is reflective of sound asset management processes and thinking."*

ICM

As the OEB has confirmed in its own reports, as well as the MAADs 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)*

[3] Vanry Report, July 4, 2017, p.4

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.[4]"*

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

This application is consistent with OEB policy in relation to the availability of ICM funding to consolidating distributors and the MAADs Decision.

Brampton, PowerStream and Enersource

Alectra Utilities has capital investment needs for the Brampton, PowerStream and Enersource RZs for 2018 that are not funded through existing distribution rates.[5] 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 Brampton, PowerStream and Enersource RZ's ICM requests, are set out in Attachments 21, 33 and 47, respectively.

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

[5] 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).

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 Tenth Line Main Feeder Subdivision Renewal. As explained in the Tenth Line Feeder Subdivision Renewal Business Case, filed as Attachment 47, Alectra Utilities' distribution system in Mississauga is 65% underground and 35% overhead. Underground cables have been identified as the asset class with the highest percentage of poor and very poor condition assets. Increasing failures on early generation underground cables are resulting in increased outages and adversely affecting reliability. The solution is to renew the early generation underground distribution cables and transformers showing signs of oil leaks in the Tenth Line area, while optimizing configuration to reduce replacement cost (i.e. by replacing the existing 14km of underground cables with 7km of new infrastructure, and by abandoning the switchgear that has reached end of life). The new cables will be installed in 4 in. ducts, making future replacements less costly.

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 33, 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.*

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.

System service investment projects include the planned rebuild of the Warden Avenue pole line, as outlined in the business case, included in Attachment 33. The feeders that currently supply Markham north are insufficient to meet projected growth from near-term and long-term area developments, including (a) the known large commercial facilities coming online in 2018 (8.5MW load); (b) Highway 404 North Development; and (c) the north Markham Future Urban Area ("FUA") expansion. The solution to this need is to rebuild the 27.6kV pole line on Warden, from 16th Ave to Major Mackenzie, to add two additional feeders, effectively extending feeders 12M10 and 12M11 into Markham North and increasing supply capacity by 40MVA by the end of 2018. An earlier phase associated with the project (rebuilding pole line on Warden from Highway 7 to 16th Ave) is expected to be completed by year end 2017.

An additional example of a system service project is the connection cost recovery agreement ("CCRA") payment due to Hydro One Networks Inc. ("HONI") in the Brampton RZ in 2018. The payment relates to the Pleasant Transformer Station ("TS") year ten true up payment. The payment is non-discretionary and is above the basis on which rates were set. Under the Transmission System Code ("TSC"), and consequently the CCRA, Alectra Utilities is required to provide HONI with an initial capital contribution based on the difference between the total capital cost of constructing the TS and a projection of transformation revenue (the "HONI Revenue") earned on the conveyance of electricity through the TS. The difference represents a contingent debt obligation for Alectra Utilities, based on the extent to which historical actual and forecast HONI Revenue during the CCRA term are less than the amount of HONI Revenue projected as a basis for the determination of the initial capital contribution.

Customer Engagement

On October 13, 2016, the OEB released the Handbook to Utility Rate Applications. This "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."*[6]

Mindful of this direction, Alectra Utilities engaged Innovative Research Group ("Innovative") to undertake customer engagement for the Enersource RZ DSP (Attachment 50), and for all rate zones to understand customer priorities and preferences (Attachment 51).

The multifaceted customer engagement program designed by Innovative included a voluntary online feedback portal, which allowed customers an opportunity to provide feedback. The number of responses to the online portal was unprecedented at over 17,500 participants; by far, the largest amount of online customer feedback collected ever witnessed by Innovative or, to its knowledge, the OEB. Innovative also undertook telephone surveys among Residential and General Service customers to ensure feedback from representative customer samples and an invitation-only online survey to canvass the views of Large Users (5MW+).

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[6] Handbook to Utility Rate Applications, October 13, 2016, p.11

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, that also addresses growth and system demands. However, customers are frustrated by 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."

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 October 26, 2016 with a subsequent update anticipated November 2017;
- 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: 2014 Benchmarking Update* for determination of Stretch Factor Assignments for 2017 dated July 30, 2015;
- *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 3 Incentive Rate Setting Applications* issued July 14, 2016 (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 14, 2016;
- *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 third Annual Filing for the Horizon Utilities RZ, 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 and 2017 Annual Filings, for approval of its proposed distribution rates and other charges, effective January 1, 2018. This annual filing impacts customers in the Cities of Hamilton and St. Catharines.

Alectra Utilities has calculated adjustments to its 2018 revenue requirement for the Horizon Utilities RZ using the Cost of Service Models (i.e., Revenue Requirement Work Form, Income Tax/PILs Work Form, 2017 RTSR Work Form and Cost Allocation Models) and directions provided by the Board in July 2016 for 2017 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, 2015.

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 2016 Regulated Return on Equity ("ROE") for the purposes of earnings sharing;

b. The calculation of its 2016 capital additions for the purpose of calculating the 2016 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 2018 Street Lighting Class revenue-to-cost ratio ("RCR") by 6.67% to 106.66% from the 2017 RCR of 113.33%;

e. The recovery of the remaining balance of stranded meter assets including a return on those assets equal to the short term debt rate as established by the Board in its Cost of Capital parameters in 2018;

f. The clearance of the balances recorded in certain deferral and variance accounts by means of class-specific rate riders effective January 1, 2018 to December 31, 2018;

g. 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, 2016, by means of customer-specific bill adjustments for each new Class A customer;

h. 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

i. An adjustment to retail transmission service rates effective January 1, 2018;

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

k. That its current (i.e., 2017) rates provided in Attachment 1 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018; and

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, 2018 OEB models for IRM and ICM applications were not yet available. Alectra Utilities developed its models for the IRM ("IRM Model") and ICM ("ICM Model") for use in this application that were based on the most recently available models from the OEB.

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. 2018 Renewable Generation Connection Rate Protection;
f. Incremental capital funding;
g. Summary of Rates and Riders Requested; and
h. Summary of Bill Impacts.

Relief Sought – Brampton RZ

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

a. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;

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, 2016, 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. An adjustment to the retail transmission service rates effective January 1, 2018;

g. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers;

h. Incremental capital rate riders effective January 1, 2018 until the next rebasing application; and

i. Current (i.e., 2017) rates provided in Attachment 14 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

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, 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’ 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. Establishment of a new deferral account;
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 – PowerStream RZ

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

a. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;
d. 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;
e. An adjustment to the retail transmission service rates effective January 1, 2018;
f. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers;
g. Disposition of LRAMVA amounts related to CDM activities in 2011 to 2015 over a one-year period;
h. Incremental capital rate riders effective January 1, 2018 until the next rebasing application;

i. Approval of an accounting order for a new deferral account to record incremental capital expenditures for the Metrolinx Crossings Remediation Project; and

j. Current (i.e., 2017) rates provided in Attachment 23 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

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. Establishment of a new deferral account;

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. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;

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, 2016, 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. An adjustment to the retail transmission service rates effective January 1, 2018;

g. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers;

h. Disposition of LRAMVA amounts related to CDM activities in 2011 to 2015 over a one-year period;

i. Incremental capital rate riders effective January 1, 2018 until the next rebasing application;

j. Approval of an accounting order for a new deferral account to record incremental capital expenditures for the GO Rail Network Electrification Project; and

k. Current (i.e., 2017) rates provided in Attachment 36 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

Proposed Effective Date of Rate Order

Alectra Utilities proposes that the Board make its Rate Order, together with the other relief sought in this Annual Filing, effective January 1, 2018. 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 Schedule of Rates and Charges is provided in Attachments 2, 15, 24 and 37 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., 2017) rates provided in Attachments 1, 14, 23 and 36 as interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates, effective January 1, 2018.

1. 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, 2018, the Board approve a rate rider that would provide for the recovery of foregone revenue for the period from January 1, 2018 to the implementation date of the 2018 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 July, 2017.

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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.

The Annual Filing incorporated changes as a result of the OEB's New Cost Allocation Policy for 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 and second year transition adjustment in its proposed rates for 2016 and 2017 in a manner consistent with OEB policy.

Alectra Utilities is now seeking adjustments to 2018 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 and 2017 Annual Filings. This annual filing impacts customers in the Cities of Hamilton and St. Catharines.

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

a. The calculation of the 2016 Regulated Return on Equity ("ROE") for the purposes of earnings sharing;

b. The calculation of its 2016 capital additions for the purpose of calculating the 2016 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 106.66% from the 2017 RCR of 113.33%;

e. The recovery of the remaining balance of stranded meter assets including a return on those assets equal to the short term debt rate as established by the Board in its Cost of Capital parameters in 2018;

f. The clearance of the balances recorded in certain deferral and variance accounts by means of class-specific rate riders effective January 1, 2018 to December 31, 2018;

g. 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, 2016, by means of customer-specific bill adjustments for each new Class A customer;

h. 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

i. An adjustment to retail transmission service rates effective January 1, 2018;

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

k. That its current (i.e., 2017) rates provided in Attachment A be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018; and

This Annual Filing has been prepared in accordance with the Decisions of the Board in Horizon Utilities RZ's 2015 Custom IR, 2016 and 2017 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 2018 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 third year transition adjustment in its proposed rates for 2018 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 and CDM);* Horizon Utilities implemented the Ontario Energy Support Program ("OESP") on January 1, 2016 to provide support to eligible low-income customers. It was funded through electricity rates as a volumetric charge of $0.0011/kWh up until April 30, 2017 and is delivered as a reduction on qualifying customers' bills.

  On March 2, 2017, the Ontario government announced the Fair Hydro Plan (the "OFHP") to reduce residential electricity bills in Ontario by 17%. The OFHP: i) extended the payback period for items within the Global Adjustment ("GA"), and ii) transferred the funding of certain support programs, such as the Ontario Energy Support Program ("OESP") from the electricity rate base to the tax base. A portion of the bill reduction announced in the OFHP, achieved through a reduction in Regulated Price Plan ("RPP") prices, in addition to the removal of the OESP charge of $0.0011/kWh, took effect on May 1, simultaneous with the RPP changes. The final portion of the bill reduction, achieved through a further reduction in RPP prices, in addition to a reduction to the Rural and Remote Rate Protection ('RRRP") charge from $0.0021/kWh to $0.0003/kWh, took effect on July 1.

Accordingly, Alectra Utilities has incorporated the removal of the OESP and reduction to the RRRP charge in the Horizon Utilities RZ, in addition to the RPP changes, in its cost of power calculations. The RPP changes are discussed in further detail below.

- *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 (following the consolidation) 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.

  There is no revenue requirement impact to the 2018 Annual Filing for the Horizon Utilities RZ, as a result of this change.

- *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. Alectra Utilities will address any directions from the Board arising out of the proceeding for the Horizon Utilities RZ at a later date, as may be necessary.

- *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).

- *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."*

Alectra Utilities has derived its 2018 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 113.33% in 2017 to 106.66% in 2018.

Annual Adjustments

- *Changes in the Cost of Capital.* This Annual Filing has been updated for the 2017 Cost of Capital parameters issued by the OEB on October 27, 2016. Horizon Utilities RZ will make a subsequent update for the 2018 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") Price Report on April 20, 2017 and the RPP Prices and the Global Adjustment Modifier Report on June 22, 2017. RPP rates, the Hourly Ontario Energy Price ("HOEP") and Global Adjustment Rates were updated to the most recent rates effective from July 1, 2017 to April 30, 2018. The Power and Global Adjustment charges incorporate the bill reduction implemented as part of the Fair Hydro Plan, as mentioned above. 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 effective November 1, 2017 for the Horizon Utilities RZ.
    - Retail Transmission Service Rates ("RTSRs") have been updated to incorporate 2016 demand for the Horizon Utilities RZ, and 2017 Hydro One Uniform Transmission Rates ("UTRs") and Sub Transmission Rates ("STRs") approved by the OEB January 14, 2016 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 2016 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. There was no change to the Rate Rider for the SME Charge; the Rate Rider expires on October 2018. The Provincial Smart Metering Initiative permitted the IESO to recover the cost of developing, implementing and operating the SME and provincial data centre through a Smart Metering Charge of $0.79/month from May 1, 2013, to October 31, 2018;
    - The ratio of RPP vs. non-RPP volumes has been updated for 2016 actuals. The ratio approved in Horizon Utilities' Custom IR was based on 2013 actuals;

- The Rural or Remote Electricity Rate Protection ("RRRP") Charge has been 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;
- 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, as previously discussed, and therefore has not 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"*. While this is not an IRM application, 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, 2015 was \$1,281,317.

- *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, 2016, 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

Description	Account	$ Total Disposition
Low Voltage	1550	$561,804
Smart Meter Entity Charge (Residential and GS<50 Classes only)	1551	($24,050)
Wholesale Market Service Charge ("WMS") excluding Capacity Based Recovery ("CBR") A	1580	($4,746,333)
Retail Transmission Network Charge	1584	($537,595)
Retail Transmission Connection Charge	1586	$959,790
Power	1588	($1,134,428)
Global Adjustment	1589	($3,038,034)
Cost of Service EB-2015-0075 (2016)	1595	$588,675
Total for Disposition		**($7,370,171)**

- *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 the 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".

Alectra Utilities reports the results for Horizon Utilities for 2016 in this Annual Filing, the second year for which the ESM is in place. Regulatory net income and ROE reported for 2016 for the purposes of earnings sharing were $20,009,623 and 9.877%, respectively, as identified in Table 2 below. This compares to the regulatory net income and ROE of $18,223,662 and 9.19% approved in Horizon Utilities' 2016 Annual Filing Application (EB-2016-0077). Horizon Utilities incurred earnings in excess of the 2016 approved ROE of $1,391,949. 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 $695,975 for 2016. Horizon Utilities reported $662,467 in deferral account 1508 Sub-account Earnings Sharing Variance Account in its 2016 Reporting and Record Keeping Requirements ("RRRs") for 2016; which was based on best estimates of the calculation at that time. An update to the earnings for actuals resulted in a difference of $33,508 in the amount of earnings sharing, to the account of the ratepayer. Alectra Utilities proposes that this difference be reported in the 2017 deferral account balances and that the full amount of $695,575 be disposed of in 2018.

Alectra Utilities seeks approval for the calculation of its 2016 achieved ROE of 9.877% for Horizon Utilities, for the purposes of earnings sharing. Detailed calculations are provided in Exhibit 2, Tab 1, Schedule 6.

Table 2 - 2016 Regulatory Net Income and ROE – Horizon Utilities RZ

2016 Regulatory ROE	2016 Actuals ESM	Annual Filing EB-2015-0075
Regulatory Net Income	$20,009,623	$18,223,662
Deemed Equity	$202,586,220	$198,298,824
Return on Equity	9.877%	9.190%

% Return in Excess of 9.19%	0.687%
$ Return in Excess of 9.19%	$1,391,949
Amount Payable to Rate Payers	$695,975

- 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”[7]) 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.

[7] Referred to as the Capital Expenditure Variance Account in the Decision of the Board dated December 11, 2015.

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 "Capital Investment Variance Account" ("CIVA"). This was approved by the Board.

Alectra Utilities reports the capital additions for 2016 for the Horizon Utilities RZ in this Annual Filing. As identified in Table 3 below, Horizon Utilities' actual capital additions for 2016 were $44,295,265, $3,147,731 higher than the capital additions of $41,147,533 forecast in its Custom IR Application. 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. Actual capital additions for 2016 of $44,295,265 are consistent with Alectra Utilities RRR 2.1.5.2 Capital filed April 28, 2017 for the Horizon Utilities RZ. Forecasted capital additions for 2016 of $41,147,533 were approved by the Board in Horizon Utilities' Settlement Agreement for its Custom IR Application (refer to Settlement Table 9, page 33). Alectra Utilities seeks approval of Horizon Utilities' 2016 capital additions of $44,295,265 as reported in its RRR 2.1.5.2 Capital filed April 28, 2017 for the purpose of calculating the 2016 entry to the CIVA.

Table 3 – 2016 Capital Additions – 2016 Actual vs. Custom IR Application (EB-2014-0002) – Horizon Utilities RZ

2016 Capital Additions	2016 Actuals	Custom IR Application (EB-2014-0002)	2016 Actuals vs. Custom IR
Gross Capital Additions	$51,929,703	$45,802,533	$6,127,170
Less Capital Contributions	$7,634,439	$4,655,000	($2,979,439)
Net Capital Additions	$44,295,265	$41,147,533	$3,147,731

- 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 4, 2016 (August 4, 2016 Report). The August 4, 2016 Report placed Horizon Utilities in Group III among Ontario distributors for the purposes of calculating stretch factors for 2017.

The August 4, 2016 Report is the most recent report issued by the OEB; therefore Horizon 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 4, 2016 Report, no Efficiency Adjustment should be made to the revenue requirement for the 2018 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 2018 in August of 2017.

- 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 2017 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 7 – Alectra Utilities has updated the 2017 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 8 provides a summary of the proposed Fixed and Variable percentages for 2018 for the Horizon Utilities RZ;
- RTSR Work Form – Alectra Utilities has updated the 2017 RTSR Work Form v 1.1, filed as Attachment 9, to incorporate: i) Hydro One 2017 UTRs and STRs approved by the OEB on January 14, 2017; and ii) an update to Horizon Utilities RZ's demand from 2015 to 2016 actual values;
- Income Tax/Payments in Lieu of Taxes ("PILs") Work Form – Alectra Utilities has updated the 2017 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 11 – Alectra Utilities has completed the 2017 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, 2015.

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 Street Lighting Adjustment Factor ("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."*

2018 Cost Allocation

Alectra Utilities has completed the OEB's 3.4 Cost Allocation Model ("Board 3.4 CA Model") for 2018 for the Horizon Utilities RZ and, in accordance with the OEB's Decision on Horizon Utilities' 2016 and 2017 Annual Filings, has incorporated (i) the new SLAF as identified in Table 4 below; and (ii) the load profile for the Street Lighting class which was approved in Horizon Utilities' Custom IR Application

Table 4 – 2018 Street Lighting Adjustment Factor – Horizon Utilities RZ

Primary System	NCP4	Customers or Devices	Average NCP4 (per Customer or Device)
Residential	1,487,234	225,981	6.581
Street Lighting	38,041	52,300	0.727
Street Lighting Adjustment Factor (Primary System)			**9.048**

Alectra Utilities has calculated the 2018 Street Lighting Adjusted Connections for the Horizon Utilities RZ, based on the SLAF in Table 5, below.

Table 5 – 2018 Street Lighting Adjusted Connections - Horizon Utilities RZ

Number of Devices (A)	52,300
Street Lighting Adjustment Factor (B)	9.048
Street Lighting Adjusted Connections C=A/B	5,780

Alectra Utilities provides a comparison of the total costs allocated from the Cost Allocation Model as approved in the 2015-2019 Custom IR Decision for the Horizon Utilities RZ compared to the total costs per the revised Cost Allocation methodology i.e. inclusive of the SLAF in Table 6 below. Please refer to Exhibit 2, Tab 1, Schedule 5, for an explanation of the decrease in revenue requirement.

Table 6 – Total 2018 Costs Allocated from Cost Allocation Model – Horizon Utilities RZ

Rate Class	2018 Board Approved EB-2014-0002[1]	2018 Proposed	Increase/ (Decrease)
Residential	$72,001,565	$72,614,859	$613,294
GS < 50kW	$16,149,690	$15,962,635	($187,055)
GS > 50 to 4999kW	$24,998,731	$24,408,883	($589,848)
Standby	$1,198,889	$1,164,097	($34,792)
LU (1)	$2,386,689	$2,321,357	($65,332)
LU (2)	$1,174,754	$1,138,761	($35,992)
Sentinel Lights	$44,986	$47,452	$2,466
Street Lighting	$3,432,781	$1,750,432	($1,682,349)
Unmetered and Scattered Load	$391,436	$409,769	$18,333
Total Base Revenue Requirement	**$121,779,520**	**$119,818,245**	**($1,961,275)**

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

2018 Class Revenue to Cost Ratios

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. This is shown by rate class and is the ratio of distribution revenue collected by rate class compared to the costs allocated to the class. A ratio lower than the bottom of the Board range for the revenue-to-cost ratio for that rate class indicates the rate class is under-contributing and is being subsidized by other classes of customers. A ratio greater than the Board's top end of the range indicates the rate classification is over-contributing and is subsidizing other classes of customers.

Alectra Utilities provides a comparison of the 2018 Board Approved RCRs and the 2018 RCRs updated for the SLAF from the Cost Allocation Model for the Horizon Utilities RZ in Table 7 below.

Table 7 - 2018 Revenue to Cost Ratios before Rate Design from Cost Allocation Model - Horizon Utilities RZ

Rate Class	2018 Board Approved EB-2014-0002 Before Rate Design [1]	2018 Inclusive of SLAF Before Rate Design	OEB Approved Range
Residential	104.21%	102.14%	85%-115%
GS < 50kW	100.06%	100.85%	80%-120%
GS > 50 to 4999kW	90.62%	92.33%	80%-120%
Standby	71.86%	73.55%	80%-120%
LU (1)	111.08%	112.49%	85%-115%
LU (2)	90.84%	91.12%	85%-115%
Sentinel Lights	97.59%	92.36%	80%-120%
Street Lighting	82.60%	114.15%	80%-120%
Unmetered and Scattered Load	120.24%	114.96%	80%-120%

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

2018 Rate Design and Rate Design Steps

In addition to the implementation of the SLAF, the OEB directed Horizon Utilities to reduce the RCR for the Street Lighting Class from 120% in 2016 by 6.67% per year in each of 2017 to 2019 as previously discussed. Alectra Utilities has updated its rate design model for 2018 to include a RCR 106.66% for the Street Lighting class for the Horizon Utilities RZ. This corresponds to an increase in the RCR of 24.06% as compared to the RCR of 82.60% used in the 2015-2019 Custom IR Decision and prior to the revised Cost Allocation methodology.

As identified in Table 7 above, the 2018 RCR ratio in the 2018 cost allocation model inclusive of the SLAF was 114.15%. The first step in the rate design for 2018 was to reduce the RCR for the Street Lighting class from 114.15% to 106.66%. The next step was to adjust the RCR for those rate classes that were outside of the Board's Policy Range to the upper or lower end of the range, as applicable. There were no rate classes for which the RCR was outside of the Board's Policy Range %. The effect of reduction in the RCR for the Street Lighting class was a revenue deficiency. The associated revenue deficiency was then allocated by way of an equal percentage to all rate classes that were below 100% RCR, with the exclusion of the Standby Class. This is consistent with Horizon Utilities' approach in its Custom IR Application.

That approach was approved by the OEB in the Decision on the Application[8]. Further, the OEB also approved setting a standby charge that is equal to the variable charge proposed for the GS > 50 kW class (where most users of standby generation reside), in that Decision. Similarly, for comparison purposes, the Standby Rate for the LU (1) and LU (2) classes are adjusted, consistent with the Decision of the OEB in the Custom IR Application.

The adjusted 2018 revenue-to-cost ratios, inclusive of the SLAF are identified in Table 8 below. In the process of setting the standby charge equal to the variable charge for the GS > 50 kW class, the revenue to cost ratio falls outside the Board range, consistent with the methodology as approved in the Decision on the Custom IR Application.

Table 8 – 2018 Revenue to Cost Ratios after Rate Design – Horizon Utilities RZ

Rate Class	2018 Board Approved EB-2014-0002 After Rate Design 1	2018 Inclusive of SLAF After Rate Design	OEB Approved Range
Residential	104.21%	102.14%	85%-115%
GS < 50kW	100.06%	100.85%	80%-120%
GS > 50 to 4999kW	90.63%	92.84%	80%-120%
Standby	71.86%	73.55%	80%-120%
LU (1)	111.08%	112.49%	85%-115%
LU (2)	90.84%	91.63%	85%-115%
Sentinel Lights	97.59%	92.86%	80%-120%
Street Lighting	82.60%	106.66%	80%-120%
Unmetered and Scattered Load	120.00%	114.96%	80%-120%

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

Alectra Utilities provides a comparison of the costs and revenues by class after the implementation of the rate design steps below in Table 9 for the Horizon Utilities RZ. The resulting 2018 proposed base revenue amounts identified in Table 10 below are used to derive the proposed distribution charges in this Annual Filing.

[8] Page 10 of Horizon Utilities' Decision and Order, dated December 11, 2014

Table 9 – 2018 Proposed Revenues and Costs – Horizon Utilities RZ

Rate Class	2018 Proposed Revenues	2018 Proposed Costs	Revenue vs. Cost $	RCR
Residential	$74,165,633	$72,614,859	$1,550,773	102.14%
GS < 50kW	$16,097,695	$15,962,635	$135,059	100.85%
GS > 50 to 4999kW	$22,661,876	$24,408,883	($1,747,007)	92.84%
Standby	$856,163	$1,164,097	($307,934)	73.55%
LU (1)	$2,611,267	$2,321,357	$289,910	112.49%
LU (2)	$1,043,486	$1,138,761	($95,275)	91.63%
Sentinel Lights	$44,065	$47,452	($3,387)	92.86%
Street Lighting	$1,867,011	$1,750,432	$116,579	106.66%
Unmetered and Scattered Load	$471,050	$409,769	$61,281	114.96%
Total	**$119,818,245**	**$119,818,245**	**$0**	

Table 10 – 2018 Base and Service Revenue Requirement by Class - Horizon Utilities RZ

Rate Class	2018 Proposed Base Revenue Requirement	2018 Miscellaneous Revenue Requirement	2018 Proposed Service Revenue Requirement
Residential	$70,279,800	$3,885,832	$74,165,633
GS < 50kW	$15,408,756	$688,939	$16,097,695
GS > 50 to 4999kW	$21,668,528	$993,348	$22,661,876
Standby	$802,314	$53,849	$856,163
LU (1)	$2,466,508	$144,759	$2,611,267
LU (2)	$1,022,107	$21,379	$1,043,486
Sentinel Lights	$41,178	$2,887	$44,065
Street Lighting	$1,820,705	$46,306	$1,867,011
Unmetered and Scattered Load	$442,151	$28,899	$471,050
Total	**$113,952,047**	**$5,866,199**	**$119,818,245**

Alectra Utilities seeks OEB approval of: i) the steps outlined above on the implementation of the Street Lighting Adjustment Factor; ii) the resulting Rate Design; and iii) just and reasonable rates for the Horizon Utilities RZ for 2018.

For illustrative purposes, Alectra Utilities has completed cost allocation and rate design for 2019 for the Horizon Utilities RZ to incorporate the inclusion of the SLAF and the reduction of 6.6% per year in the RCR for the Street Lighting class.

2019 Cost Allocation and Rate Design

Alectra Utilities RZ 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 11 below.

Table 11 – 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 12 below for the Horizon Utilities RZ.

Table 12 – 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 13 below.

Table 13 – 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	$76,637,556	$1,740,655
GS < 50kW	$16,942,996	$17,021,671	$78,675
GS > 50 to 4999kW	$24,455,048	$24,306,922	($148,127)
Standby	$1,259,659	$1,248,682	($10,977)
LU (1)	$2,477,961	$2,457,791	($20,170)
LU (2)	$1,154,214	$1,148,095	($6,119)
Sentinel Lights	$45,428	$48,616	$3,188
Street Lighting	$3,515,372	$1,853,148	($1,662,224)
Unmetered and Scattered Load	$397,736	$422,836	$25,100
Total Base Revenue Requirement	**$125,145,317**	**$125,145,317**	**$0**

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

Alectra Utilities provides a comparison of the 2019 Board Approved RCRs and the 2019 RCRs updated for the SLAF from the Cost Allocation Model for the Horizon Utilities RZ in Table 14 below.

Table 14- 2019 Revenue to Cost Ratios before Rate Design from Cost Allocation Model - 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%	101.16%	85%-115%
GS < 50kW	97.81%	98.56%	80%-120%
GS > 50 to 4999kW	95.07%	97.19%	80%-120%
Standby	71.94%	73.67%	80%-120%
LU (1)	110.01%	110.97%	85%-115%
LU (2)	95.64%	95.54%	85%-115%
Sentinel Lights	96.08%	91.43%	80%-120%
Street Lighting	82.44%	104.83%	80%-120%
Unmetered and Scattered Load	119.76%	114.70%	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 15 below.

Table 15 - 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%	101.16%	85%-115%
GS < 50kW	97.81%	98.83%	80%-120%
GS > 50 to 4999kW	95.08%	97.38%	80%-120%
Standby	71.77%	73.68%	80%-120%
LU (1)	110.01%	110.92%	85%-115%
LU (2)	95.64%	95.73%	85%-115%
Sentinel Lights	96.08%	91.63%	80%-120%
Street Lighting	82.44%	100.00%	80%-120%
Unmetered and Scattered Load	119.76%	114.51%	80%-120%

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

Table 16 provides 2019 comparative information on calculated base revenue amounts used to derive proposed distribution charges.

Table 16 – 2019 Proposed Revenues and Costs – Horizon Utilities RZ

Rate Class	2019 Proposed Revenues	2019 Proposed Costs	Revenue vs. Cost $	RCR
Residential	$77,529,988	$76,637,556	$892,432	101.16%
GS < 50kW	$16,813,129	$17,021,671	($208,542)	98.77%
GS > 50 to 4999kW	$23,674,877	$24,306,922	($632,044)	97.40%
Standby	$917,997	$1,248,682	($330,685)	73.52%
LU (1)	$2,727,324	$2,457,791	$269,534	110.97%
LU (2)	$1,099,306	$1,148,095	($48,789)	95.75%
Sentinel Lights	$44,544	$48,616	($4,072)	91.62%
Street Lighting	$1,853,148	$1,853,148	$0	100.00%
Unmetered and Scattered Load	$485,004	$422,836	$62,168	114.70%
Total	**$125,145,317**	**$125,145,317**	**$0**	

Table 17 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 17 – 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%	101.16%	85%-115%
GS < 50kW	98.87%	99.01%	100.85%	98.83%	80%-120%
GS > 50 to 4999kW	94.92%	96.16%	92.84%	97.38%	80%-120%
Standby	74.16%	73.23%	73.55%	73.68%	80%-120%
LU (1)	113.50%	113.35%	112.49%	110.92%	85%-115%
LU (2)	86.53%	85.00%	91.63%	95.73%	85%-115%
Sentinel Lights	95.02%	93.57%	92.86%	91.63%	80%-120%
Street Lighting	120.00%	113.33%	106.66%	100.00%	80%-120%
Unmetered and Scattered Load	114.42%	114.34%	114.96%	114.51%	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 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 has incorporated the third year transition adjustment for the Horizon Utilities RZ in its proposed rates for 2018. The Residential portion of the proposed 2018 base revenue requirement to which the new distribution rate design applies is $70,279,800 as identified in Table 18 below.

Table 18 - Base Revenue Requirement by Rate Class – Horizon Utilities RZ

Rate Class	2018 Proposed Base Revenue Requirement
Residential	$70,279,800
GS < 50kW	$15,408,756
GS > 50 to 4999kW	$21,668,528
Standby	$802,314
LU (1)	$2,466,508
LU (2)	$1,022,107
Sentinel Lights	$41,178
Street Lighting	$1,820,705
Unmetered and Scattered Load	$442,151
Total	**$113,952,047**

Alectra Utilities has completed Appendix 2-PA for 2018 and 2019 issued by the Board on July 16, 2015, as identified in Tables 19 and 20 below. As identified in Table 20 below, Alectra Utilities fully fixed charge in 2019 for Residential customers for the Horizon Utilities RZ is $26.92/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 $119,191,418 and the 2019 Residential customer count of 227,762 for the Horizon 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 2018 distribution rates for all other rate classes using the normal formulaic derivation for the Horizon Utilities RZ.

1 **Table 19 – Appendix 2-PA – 2018 – New Rate Design Policy for Residential Customers –**
2 **Horizon Utilities RZ**

Please complete the following tables.

A) Data Inputs

Test Year Billing Determinants for Residential Class	
Customers	225,981
kWh	1,646,663,057

Proposed Residential Class Specific Revenue Requirement[1]	$ 70,279,800

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	21.34
Distribution Volumetric Rate ($/kWh)	0.0081

B) Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	21.34	225,981	$ 57,869,305	81.27%
Variable	0.0081	1,646,663,057	$ 13,337,971	18.73%
TOTAL	-	-	$ 71,207,276	-

C) Calculating Test Year Base Rates

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

	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	$ 57,115,557	21.06	$ 57,110,007
Variable	$ 13,164,244	0.0080	$ 13,173,304
TOTAL	$ 70,279,800	-	$ 70,283,312

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	90.63%	$ 63,697,679	23.49	$ 63,699,624
Variable	9.37%	$ 6,582,122	0.0040	$ 6,586,652
TOTAL	-	$ 70,279,800	-	$ 70,286,276

Checks[3]	
Change in Fixed Rate	$ 2.43
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	$ 6,475
	0.01%

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)

Table 20 – Appendix 2-PA – 2019 – New Rate Design Policy for Residential Customers – Horizon Utilities RZ

Please complete the following tables.

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]	$ 73,581,229

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	23.49
Distribution Volumetric Rate ($/kWh)	0.004

B) Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	23.49	227,762	$ 64,201,676	90.66%
Variable	0.004	1,652,719,193	$ 6,610,877	9.34%
TOTAL	-	-	$ 70,812,553	-

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	$ 66,711,876	24.41	$ 66,716,173
Variable	$ 6,869,353	0.0042	$ 6,941,421
TOTAL	$ 73,581,229	-	$ 73,657,594

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 73,581,229	26.92	$ 73,576,378
Variable	0.00%	$ -	0.0000	$ -
TOTAL	-	$ 73,581,229	-	$ 73,576,378

Checks[3]	
Change in Fixed Rate	$ 2.51
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	-$ 4,851
	-0.01%

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 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 for the Horizon RZ the Residential monthly service charge increase of $2.21 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 10^{th} consumption percentile. The following is a description of the method Alectra Utilities used to derive the 10^{th} 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 July 1, 2016 to June 30, 2017 period for the Horizon Utilities RZ. The query produced 153,937 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 10^{th} consumption percentile for the Horizon Utilities RZ, at 220 kWh.

Alectra Utilities has provided in Table 21 below the bill impact for a Residential customer who consumes 220 kWh monthly for the Horizon Utilities RZ. The monthly service charge increased by $2.15 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 1.66%.

Table 21 – 10th Consumption Percentile Residential Customer Bill Impact (220 kWh) – Horizon Utilities RZ

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 220 kWh
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	$ 21.34	1	$ 21.34	$ 23.49	1	$ 23.49	$ 2.15	10.07%
Distribution Volumetric Rate	$ 0.0081	220	$ 1.78	$ 0.0040	220	$ 0.88	$ (0.90)	-50.62%
Fixed Rate Riders	$ 0.79	1	$ 0.79	$ (0.16)	1	$ (0.16)	$ (0.95)	-120.25%
Volumetric Rate Riders	$ -	220	$ -	$ 0.0003	220	$ 0.06	$ 0.06	
Sub-Total A (excluding pass through)			$ 23.91			$ 24.27	**$ 0.36**	**1.49%**
Line Losses on Cost of Power	$ 0.0822	8	$ 0.69	$ 0.0822	8	$ 0.69	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0026	220	$ (0.57)	-$ 0.00095	220	$ (0.21)	$ 0.36	-63.46%
Low Voltage Service Charge	$ 0.0001	220	$ 0.01	$ 0.0001	220	$ 0.01	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24.83**			**$ 25.55**	**$ 0.72**	**2.90%**
RTSR - Network	$ 0.0074	228	$ 1.69	$ 0.0075	228	$ 1.72	$ 0.03	1.86%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0059	228	$ 1.35	$ 0.0060	228	$ 1.38	$ 0.03	2.42%
Sub-Total C - Delivery (including Sub-Total B)			**$ 27.87**			**$ 28.65**	**$ 0.78**	**2.81%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	228	$ 0.82	$ 0.0036	228	$ 0.82	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	228	$ 0.07	$ 0.0003	228	$ 0.07	$ -	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	143	$ 9.30	$ 0.0650	143	$ 9.30	$ -	0.00%
TOU - Mid Peak	$ 0.0950	37	$ 3.55	$ 0.0950	37	$ 3.55	$ -	0.00%
TOU - On Peak	$ 0.1320	40	$ 5.23	$ 0.1320	40	$ 5.23	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 47.08**			**$ 47.86**	**$ 0.78**	**1.66%**
HST	13%		$ 6.12	13%		$ 6.22	$ 0.10	1.66%
8% Provincial Rebate	-8%		$ (3.77)	-8%		$ (3.83)	$ (0.06)	1.66%
Total Bill on TOU			**$ 49.43**			**$ 50.26**	**$ 0.82**	**1.66%**

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, 2017; (ii) Hydro One 2016 UTRs and STRs approved by the OEB January 14, 2016; (iii) an update to the Alectra Utilities demand for the Horizon Utilities RZ from 2015 to 2016 actuals in the RTSR model; (iv) an increase to the SME charge as a result of an update to the number of customers; (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) an increase in the Rural and Rural or Remote Electricity Rate Protection (“RRRP”) Charge from $0.0013/kWh to $0.0021/kWh.

A summary of the changes to the Cost of Power is provided in Table 22 below.

Table 22 – Cost of Power 2018 Annual Filing vs. Custom IR – Horizon Utilities RZ

Category	2018 Annual Filing	2018 Custom IR (EB-2014-0002)	Variance	% Variance
Power	$278,185,599	$295,596,548	($17,410,948)	(5.89%)
Global Adjustment	$173,755,686	$190,626,639	($16,870,953)	(8.85%)
Wholesale Market Services	$19,230,919	$28,106,728	($8,875,809)	(31.58%)
Network	$38,452,453	$40,891,141	($2,438,688)	(5.96%)
Connection	$31,503,553	$30,814,906	$688,647	2.23%
Low Voltage	$313,362	$313,362	$0	0.00%
Smart Meter Entity	$1,907,630	$1,904,499	$3,131	0.16%
TOTAL	**$543,349,203**	**$588,253,823**	**($44,904,620)**	**(7.63%)**

The Cost of Power has decreased $44,904,620, with a corresponding decrease of $66,098 to revenue requirement, as identified in Table 23, below.

Table 23 – Impact to Revenue Requirement due to Cost of Power Update – Horizon RZ

Description	%	Amount
Cost of Power Increase		($44,904,620)
Increase to Working Capital/Rate Bas	12.00%	($5,388,554)
Rate Base Breakdown		
Short Term Debt Increase	4.00%	($215,542)
Long Term Debt Increase	56.00%	($3,017,590)
Equity Increase	40.00%	($2,155,422)
Revenue Requirement Components		
Deemed Interest - Short Term Debt	2.16%	($4,656)
Deemed Interest - Long Term Debt	3.62%	($109,307)
Return on Equity	9.30%	($200,454)
PILs Gross-Up	26.50%	($72,273)
Total Revenue Requirement Increa	**7.18%**	**($386,689)**

Revenue requirement has also been updated from Horizon Utilities' Custom IR Application to incorporate the Cost of Capital parameters issued by the Board on October 27, 2016. 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 $1,587,943 as a result of the change in Cost of Capital parameters as identified in Table 24 below.

Table 24– Impact to Revenue Requirement due to Update of Cost of Capital Parameters – Horizon Utilities RZ

Description	%	2018 Custom IR Application EB-2014-0002	%	2018 Annual Filing After COP Update	%	2018 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		$532,017,706		$531,096,625		$531,096,625	($921,081)	$0
Rate Base Breakdown								
Short Term Debt	4.00%	$21,280,708	4.00%	$21,243,865	4.00%	$21,243,865	($36,843)	$0
Long Term Debt	56.00%	$297,929,915	56.00%	$297,414,110	56.00%	$297,414,110	($515,805)	$0
Deemed Equity	40.00%	$212,807,082	40.00%	$212,438,650	40.00%	$212,438,650	($368,432)	$0
Revenue Requirement Components								
Deemed Interest - Short Term Debt	2.16%	$459,663	2.16%	$458,867	1.76%	$373,892	($796)	($84,975)
Deemed Interest - Long Term Debt	3.62%	$10,791,992	3.62%	$10,773,307	3.62%	$10,773,307	($18,684)	$0
Return on Equity	9.30%	$19,791,059	9.30%	$19,756,794	8.78%	$18,652,113	($34,264)	($1,104,681)
PILs Gross-Up	26.50%	$7,135,552	26.50%	$7,123,198	26.50%	$6,724,912	($12,354)	($398,286)
Total Revenue Requirement before OM&A and Deprn	**7.18%**	**$38,178,265**	**7.18%**	**$38,112,167**	**6.88%**	**$36,524,225**	**($66,098)**	**($1,587,943)**

Table 25 below identifies the significant changes in the revenue requirement proposed for 2018 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 $66,098) and the Cost of Capital Parameters (decrease of $1,587,943) is a decrease to revenue requirement of $1,654,041.

Table 25 - 2018 Summary of Significant Changes – Horizon Utilities RZ

2018 Summary of Significant Changes

Note	Description	Custom IR EB-2014-0002	Changes	2018 Annual Filing EB-2017-0024
Rate Base:				
	Average Net Fixed Assets	$ 453,910,872	$ -	$ 453,910,872
1	Working Capital Base	$ 650,890,280	$ (44,904,620)	$ 605,985,660
	Working Capital Factor	12.00%	0.00%	12.00%
2	Working Capital Allowance	$ 78,106,834	$ (5,388,554)	$ 72,718,279
	Total Rate Base	**$ 532,017,706**	**$ (5,388,554)**	**$ 526,629,152**
Revenue Requirement:				
3	Deemed Interest on Debt	$ 11,251,655	$ (198,223)	$ 11,053,432
4	Return on Equity (ROE)	$ 19,791,059	$ (1,295,843)	$ 18,495,216
	Total Return on Rate Base	**$ 31,042,714**	**$ (1,494,066)**	**$ 29,548,647**
	Depreciation	$ 24,667,457	$ -	$ 24,667,457
	OM&A	$ 62,322,555	$ -	$ 62,322,555
	Property Tax	$ 313,902	$ -	$ 313,902
5	PILs	$ 3,432,893	$ (467,209)	$ 2,965,684
Service Revenue Requirement		**$ 121,779,520**	**$ (1,961,275)**	**$ 119,818,245**
7	Revenue Offsets	$ 5,866,199	$ -	$ 5,866,199
Base Revenue Requirement		**$ 115,913,322**	**$ (1,961,275)**	**$ 113,952,047**

Notes	
1	The decrease in working capital base is the result of changes to the Cost of Power flow-through costs: (i) the RPP price reductions effective May 1, 2017 and July 1, 2017; (ii) Hydro One 2016 UTRs and STRs approved by the OEB January 14, 2016; (iii) an update to Horizon Utilities' demand from 2015 to 2016 actuals in the RTSR model; (iv) an increase to the SME charge as a result of 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 decrease in working capital allowance is due to the decrease in working capital base as a result of changes to Cost of Power flow-through costs.
3	The decrease in deemed interest on debt is due to the decrease in working capital base as a result of changes to Cost of Power flow-through costs; and a decrease in the deemed short term debt rate from 2.11% to 1.65%.
4	The decrease in return on equity is due to the decrease in the return on equity from 9.30% to 8.78% and a decrease in working capital base as a result of changes to Cost of Power flow-through costs.
5	The decrease in PILs is due to the decrease in the Cost of Capital Parameters and a decrease 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 2016 for the Horizon Utilities RZ in this annual filing, the second year for which the ESM is in place. The 2016 regulatory net income and ROE have been calculated in accordance with the Settlement Agreement. Specifically, the 2016 regulatory net income reported in RRR 2.1.7 and filed with the OEB on April 28, 2017 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 costs associated with the merger of the legacy Horizon Utilities, Enersource and PowerStream such as: payments for due diligence professional services; consulting fees in respect of the proposed merger and business valuation; and legal fees in respect of the proposed merger and acquisition of Hydro One Brampton shares by the merged entity. These costs have been included in the regulatory net income reported in RRR 2.1.7 as per direction from OEB staff; but should be excluded from regulatory net income reported in RRR 2.1.5.6. Merger costs were not included in the calculation of ROE in Horizon Utilities' Custom IR Application;

- 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 2016 Conservation and Demand Management ("CDM") Incentive Payments for the Horizon Utilities RZ of $440,900 and non-LEAP donations of $33,876 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 used the Cost of Capital parameters approved in Horizon Utilities' 2016 Annual Filing; and
- PILs shall be recalculated from actual to reflect the adjusted net income as a result of any revenue and expense adjustments.

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.

The 2016 regulatory net income, excluding deferred taxes, reported by Alectra Utilities for the former Horizon Utilities before an entry to the deferral account 1508 Sub-account Earnings Sharing Variance Account ("ESM DVA") was $21,154,508 as identified in Table 26 below. A net adjustment of ($719,722), based on the items identified above, was made to the regulatory net income reported on the same basis as 2.1.7 to determine regulatory net income reported on the same basis as in RRR 2.1.5.6 of $20,434,786.

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

- Exclude the Rate of Return on Stranded Meters at the short term debt rate of 1.65%;
- 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 from actual 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.

The 2016 regulatory net income reported by Alectra Utilities for the former Horizon Utilities, on the same basis as RRR 2.1.5.6, was $20,434,786, and prior to an entry to the ESM DVA, is identified in Table 26 below. A net adjustment of ($425,163), based on the items identified above, was made to the regulatory net income reported on the same basis as 2.1.5.6 to determine regulatory net income reported for the purposes of earnings sharing of $20,009,623. This compares to the regulatory net income of $18,223,662 approved in Horizon Utilities' Custom IR Application.

The net income figures identified in Table 27 above as calculated on the same basis as RRRs 2.1.7 and 2.1.5.6 of $21,154,508 and $20,434,786 respectively, will not balance to the net income before deferred taxes filed for these RRRs, as they do not include the entry to the ESM DVA. In order to calculate the correct amount of the ESM, net income prior to the entry to the ESM DVA must be used. Once the tax effected entry to the ESM DVA is considered, the net income figures of $20,667,595 and $19,947,873 identified in Table 26 below balance to the net income before deferred taxes filed for RRRs 2.1.7 and 2.1.5.6, respectively.

A reconciliation of current income tax is provided in Table 27 below.

Table 26 – Calculation of 2016 Regulatory ROE – Horizon Utilities RZ

2016 Regulatory ROE	2016 Actuals as per 2.1.7	2016 Actuals as per 2.1.5.6	2016 Actuals ESM	Annual Filing EB-2015-0075
Regulatory Net Income including Merger Costs; before 2.1.5.6 Adjustments; before ESM DVA entry	**$25,629,954**	**$25,629,954**	**$26,292,420**	**$22,972,306**
Add Back Merger Costs		($2,331,217)	($2,331,217)	
(Deduct Net Interest Revenue) on DVAs		$195,670	$195,670	
Add back Net Interest Expense on DVAs		($190,628)	($190,628)	
Deduct non rate regulated items		$440,900	$440,900	
Add back non-LEAP Donations		($33,876)	($33,876)	
Add back Interest Expense on P&L		($7,361,508)	($7,361,508)	
Deduct Deemed Interest		$10,179,958	$10,179,958	
Regulatory Net Income after 2.1.5.6 Adjustments; before ESM Adjustments; before ESM DVA entry	**$26,292,420**	**$25,393,121**	**$25,393,121**	**$22,972,306**
Deduct Rate of Return on Stranded Meters Revenue			$83,068	n/a
Deduct 1/5th of One-time costs incurred for the Custom IR Application			$495,385	n/a
Regulatory Net Income after ESM Adjustments; before ESM DVA entry	**$26,292,420**	**$25,393,121**	**$24,814,668**	**$22,972,306**
Current Income Taxes before ESM entry	$5,137,913	$4,958,335	$4,805,045	$4,748,644
Regulatory Net Income before ESM DVA entry	**$21,154,508**	**$20,434,786**	**$20,009,623**	**$18,223,662**
Deemed Equity	$202,586,220	$202,586,220	$202,586,220	$198,298,824
Return on Equity	**10.442%**	**10.087%**	**9.877%**	**9.190%**

Regulatory Net Income before ESM DVA entry	**$21,154,508**	**$20,434,786**	**$20,009,623**	**$18,223,662**
ESM DVA entry before tax	($695,975)	($695,975)	n/a	n/a
ESM DVA entry to be booked in 2017	$33,508	$33,508	n/a	n/a
Tax on ESM DVA	$175,554	$175,554	n/a	n/a
Regulatory Net Income after ESM DVA entry [1]	**$20,667,595**	**$19,947,873**	**$20,009,623**	**$18,223,662**
Deemed Equity	$202,586,220	$202,586,220	$202,586,220	$198,298,824
Return on Equity	**10.202%**	**9.847%**	**9.877%**	**9.190%**

1. per 2.1.7 and 2.1.5.6 before deferred taxes

Table 27 – Calculation of Current Taxes – Horizon Utilities RZ

Adjustments	Income before Tax	Current Tax Impact	Tax Rate
RRR 2.1.7	**$25,629,954**	**$4,962,359**	**19.36%**
Add Back ESM DVA Entry	$662,467	$175,554	26.50%
RRR 2.1.7 prior to ESM DVA Entry	**$26,292,420**	**$5,137,913**	**19.54%**
Add Back Merger Costs [1]	($2,331,217)	$0	0.00%
(Deduct Net Interest Revenue) on DVAs	$195,670	($51,853)	26.50%
Add back Net Interest Expense on DVAs	($190,628)	$50,516	26.50%
Deduct non rate regulated items	$440,900	($116,839)	26.50%
Add back non-LEAP donations	($33,876)	$8,977	26.50%
Add back Interest Expense on P&L	($7,361,508)	$1,950,800	26.50%
Deduct Deemed Interest	$10,179,958	($2,697,689)	26.50%
Record Tax on Stranded Meter Rate Rider as per Custom IR Application		$676,509	
Total Adjustments to 2.1.7	**$899,300**	**($179,578)**	
RRR 2.1.5.6 - prior to entry to ESM DVA	**$25,393,121**	**$4,958,335**	**19.53%**
Deduct Rate of Return on Stranded Meters Revenue	$83,068	($22,013)	26.50%
Deduct 1/5th of One-time costs incurred for the Custom IR Application	$495,385	($131,277)	26.50%
Total Adjustments to 2.1.5.6	**$578,453**	**($153,290)**	
Earnings Sharing	**$24,814,668**	**$4,805,045**	**19.36%**

1. Merger Costs treated as Eligible Capital Expenditures; 100% of tax expense is deferred

The calculation of deemed equity used to determine the ROE is provided in Table 28 below.

Table 28 – Calculation of Deemed Equity – Horizon Utilities RZ

Deemed Equity Calculation	RRR 2.1.7	RRR 2.1.5.6 and ESM
Cost of Power	$610,882,333	$610,882,333
Operating Expenses	$61,631,155	$61,631,155
Total Cost of Power and Operating Expenses including Merger Costs	$672,513,487	$672,513,487
Deduct Merger Costs		($2,331,217)
Total Cost of Power and Operating Expenses excluding Merger Costs	$672,513,487	$670,182,271
Working Capital Allowance %	12.0%	12.0%
Total Working Capital Allowance	**$80,701,618**	**$80,421,872**
Fixed Assets		
Opening Balance - NBV	$415,903,516	$415,903,516
Closing Balance - NBV	$436,183,839	$436,183,839
Average NBV	**$426,043,677**	**$426,043,677**
Total Rate Base	**$506,745,296**	**$506,465,550**
Regulated Deemed Equity @ 40%	**$202,698,118**	**$202,586,220**

The adjustments to the regulatory net income required for the purposes of earnings sharing result in an achieved ROE of 9.877%, as identified in Table 29 below. Horizon Utilities' approved ROE for 2016 was 9.19%. Horizon Utilities incurred earnings in excess of the 2016 approved ROE and as such has established, and made an entry to, the ESM deferral account 1508 Sub-account "Earnings Sharing Variance Account". Alectra Utilities seeks approval for the calculation of Horizon Utilities' 2016 achieved ROE of 9.877%; net income of $20,009,623; and excess earnings of $1,391,949 for the purposes of earnings sharing as identified in Table 29 below. This results in an amount payable to ratepayers of $695,975.

As identified above, Alectra Utilities reported $662,467 in deferral account 1508 Sub-account Earnings Sharing Variance Account in the 2016 RRRs for Horizon Utilities; which was based on best estimates at the time of the calculation. An update to the earnings for actuals resulted in a difference of $33,508 in the amount of earnings sharing, to the account of the ratepayer. Alectra Utilities proposes that this difference be reported in the 2017 deferral account balances and that the full amount of $695,975 be disposed of in 2018. Table 30 below identifies (i) the amount to be disposed of by rate class; and (ii) the corresponding rate riders. The live model used to determine the rate riders is filed as Attachment 10.

Table 29 – Summary of ESM Calculation – Horizon Utilities RZ

2016 Regulatory ROE	2016 Actuals ESM	Annual Filing EB-2015-0075
Regulatory Net Income	$20,009,623	$18,223,662
Deemed Equity	$202,586,220	$198,298,824
Return on Equity	9.877%	9.190%

% Return in Excess of 9.19%	0.687%
$ Return in Excess of 9.19%	$1,391,949
Amount Payable to Rate Payers	$695,975

Table 30 – Proposed Rate Riders to Dispose of Earnings Sharing Amount - Horizon Utilities RZ

Earnings Sharing Rate Rider	Total $	Fixed $	Variable $	Variable Charge
RESIDENTIAL	($426,578)	(0.16)	0.0000	$/kWh
GENERAL SERVICE LESS THAN 50 KW	($93,527)	(0.25)	(0.0001)	$/kWh
GENERAL SERVICE > 50 KW	($139,952)	(2.27)	(0.0153)	$/kW
LARGE USE 1	($14,971)	(142.57)	(0.0084)	$/kW
LARGE USE 2	($6,168)	(33.55)	(0.0020)	$/kW
UNMETERED SCATTERED LOAD	($2,684)	(0.05)	(0.0001)	$/kWh
SENTINEL LIGHTING	($248)	(0.03)	(0.0900)	$/kW
STREET LIGHTING	($11,847)	(0.01)	(0.0343)	$/kW
TOTAL	($695,975)			

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, 2016, in the amount of ($14,781,383) have been adjusted for the following items to determine the amount for disposition of ($7,370,171) as identified in Table 31 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 must be 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*". 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 31 – Group 1 Balances for Disposition – Horizon Utilities RZ

Description	Amount
Group 1 Account Balances as of December 31, 2016	**($14,781,383)**
Subtract 2016 Annual Filing Disposition (EB-2015-0075) - Repayment to Customers	($8,484,548)
RPP Settlement True-up Claims Adjustment	($988,885)
Add Projected Carrying Charges	($84,451)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($7,370,171)**

Alectra Utilities has computed the disposition threshold for the Horizon Utilities RZ, based on the adjusted Group 1 balances to be ($0.0014)/kWh, as identified in Table 32 below. Alectra Utilities requests disposition of its Group 1 account balances in this Annual Filing for the Horizon Utilities RZ.

Table 32 - Calculation of Disposition Threshold – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	$1,033,911
Smart Meter Entity Charge	1551	($46,827)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	$937,590
RSVA - Wholesale Market Service Charge excluding CBR	1580	($15,066,306)
RSVA - Retail Transmission Network Charge	1584	($1,784,076)
RSVA - Retail Transmission Connection Charge	1586	$717,798
RSVA - Power	1588	($997,132)
RSVA - Global Adjustment	1589	($347,414)
Disposition and Recovery/Refund of Regulatory Balances	1595	$771,073
Group 1 Account Balances as of December 31, 2016		**($14,781,383)**
Subtract 2016 Annual Filing Disposition (EB-2015-0075) - Repayment to Customers		($8,484,548)
RPP Settlement True-up Claims Adjustment		($988,885)
Add 2016 Projected Carrying Charges		($84,451)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($7,370,171)**
2016 kWhs		5,412,665,721
Threshold Test $/kWh		**($0.0014)**

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 2016 RRR, section 2.1.7 for the Horizon Utilities RZ, as identified in Table 33, below. Alectra Utilities confirms that the last Board approved balance of ($8,484,548) for the Horizon Utilities RZ has been transferred to Account 1595 (as identified in Horizon Utilities Annual Filing EB-2015-0075). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2016 RRR, section 2.1.5.4. Horizon Utilities RZ relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rate of 1.10% was relied upon to calculate forecasted interest for 2017. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 33 – Deferral and Variance Account Reconciliation – Horizon Utilities RZ

Account Description	Account	Principal Amounts as of Dec 31, 2016	Carrying Charges to Dec 31, 2016	Principal Disposition during 2017 - instructed by Board EB-2016-0077	Interest Disposition during 2017 - instructed by Board EB-2016-0077	Projected Carrying Charges to Dec 31, 2017	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims Adjustment	Projected Carrying Charges to December 31, 2017	Total Disposition after RPP True-Up Adjustment
Group 1 Accounts:										
Low Voltage	1550	1,023,780	10,131	(471,028)	(7,159)	6,080	561,804			561,804
Smart Meter Entity Charge	1551	(46,354)	(473)	22,681	356	(260)	(24,050)			(24,050)
RSVA - Wholesale Market Service Charge - CBR A	1580	(0)	-	-	-	(0)	(0)			(0)
RSVA - Wholesale Market Service Charge - CBR B	1580	922,690	14,900	(1,108,630)	(15,758)	(2,045)	(188,843)			(188,843)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(14,890,603)	(175,703)	10,407,994	150,131	(49,309)	(4,557,490)			(4,557,490)
RSVA - Retail Transmission Network Charge	1584	(1,770,037)	(14,039)	1,237,207	15,135	(5,861)	(537,595)			(537,595)
RSVA - Retail Transmission Connection Charge	1586	711,681	6,117	230,302	1,328	10,362	959,790			959,790
RSVA - Power	1588	(1,007,949)	10,817	859,776	4,321	(1,630)	(134,665)	(988,885)	(10,878)	(1,134,428)
Sub-total not including RSVA Power Global Adjustment		(15,056,791)	(148,251)	11,178,303	148,354	(42,663)	(3,921,049)	(988,885)	(10,878)	(4,920,812)
RSVA - Power Global Adjustment	1589	(392,314)	44,900	(2,612,621)	(44,945)	(33,054)	(3,038,034)			(3,038,034)
Total including RSVA Power Global Adjustment		(15,449,105)	(103,351)	8,565,682	103,409	(75,718)	(6,959,083)	(988,885)	(10,878)	(7,958,847)
Disposition and Recovery/Refund of Regulatory Balances (2015) - (COS 15)	1595	199,898	(15,356)	(199,898)	15,356	-				-
Disposition and Recovery/Refund of Regulatory Balances (2016) - (2016 Annual Filing)	1595	194,908	391,623	-	-	2,144	588,675			588,675
Total 1595		394,807	376,267	(199,898)	15,356	2,144	588,675	-	-	588,675
Total Group 1		**(15,054,298)**	**272,915**	**8,365,783**	**118,765**	**(73,574)**	**(6,370,408)**	**(988,885)**	**(10,878)**	**(7,370,171)**
Total Amount for Disposition		**(15,054,298)**	**272,915**	**8,365,783**	**118,765**	**(73,574)**	**(6,370,408)**	**(988,885)**	**(10,878)**	**(7,370,171)**
Total Amount for Disposition excluding WMS Charge - CBR A		**(15,054,298)**	**272,915**	**8,365,783**	**118,765**	**(73,574)**	**(6,370,408)**	**(988,885)**	**(10,878)**	**(7,370,171)**

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"*.

<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 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.

<u>Global Adjustment and Capacity Based Response ("CBR") Disposition</u>

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 three Horizon Utilities customers that qualified as Class A customers effective July 1, 2016, 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, 2016; and paid GA as Class A customers from July 1, 2016 to December 31, 2016. 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, 2016 to June 30, 2016).

There were two Horizon Utilities' customers who ceased to qualify as a Class A customer effective July 1, 2016 under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA and CBR as Class A customers up to and including June 30, 2016; and paid GA and CBR as Class B customers from July 1, 2016 to December 31, 2016.

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, 2016 to December 31, 2016).

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 34 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 ($3,038,034), of which ($2,968,042) will be disposed of via rate rider; and ($47,208) and ($22,785) will be disposed of via specific bill adjustments to the three new Class A customers and two 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 ($188,843), of which ($186,982) will be disposed of via rate rider; and ($1,256) and ($606) will be disposed of via specific bill adjustments to the three new Class A customers and two 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 ($69,993) and its CBR balance of ($1,862) related to its three new Class A customers and two new Class B customers (effective July 1, 2016) respectively, through the bill adjustments identified in the IRM Model and in Table 34 below for the Horizon Utilities RZ.

Table 34 –Disposition of GA and CBR Balances – Horizon Utilities RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($2,968,042)
Global Adjustment - New Class A Customers July 1/2016	($47,208)
Global Adjustment - New Class B Customers July 1/2016	($22,785)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**($3,038,034)**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($186,982)
Capacity Based Recovery - New Class A Customers July 1/2016	($1,256)
Capacity Based Recovery - New Class B Customers July 1/2016	($606)
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($188,843)**

A summary of the rate riders applicable to each group of customers is identified in Table 35 below.

Table 35 – 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, 2016 - Dec 31, 2016)	x	x			
Class B non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class A (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class B non-RPP (Jan 1, 2016 - Dec 31, 2016) 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 and the remaining balance in Account 1595 related to Horizon Utilities 2016 Annual Filing for 2017 rates (EB-2016-0077).

Class A customers (who were Class A from January 1 – December 31, 2016) 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 2016) 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 2016) 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, 2016) 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 36 below. The amount to be disposed of by rate rider is ($6,298,554) and the amount to be disposed of via customer specific bill adjustments is ($71,854) (($69,992) GA and ($1,862 CBR).

Table 36 – Group 1 Disposition by Customer Group – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	$561,804
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($24,050)
Retail Transmission Network Charge	1584	($537,595)
Retail Transmission Connection Charge	1586	$959,790
IRM 14	1588	$588,675
All Customers - DVA Rate Rider 1		**$1,548,624**
Power	1588	($1,134,428)
Wholesale Market Service Charge excluding CBR	1580	($4,557,490)
All Customers ex WMPs - DVA Rate Rider 2		**($5,691,917)**
Wholesale Market Service Charge - CBR Class B	1580	($186,982)
Wholesale Market Service Charge - CBR Class B/Class A Customers for Part of the Year	1580	($1,862)
All Class A Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($188,843)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2016 - Dec 31/2016	1589	($2,968,042)
Global Adjustment - Class B/Class A Customers for Part of the Year	1589	($69,992)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**($3,038,034)**
Total (Repayment to)/Recovery from Customers		**($7,370,171)**
Disposition via Rate Rider		($7,298,317)
Disposition via Customer Specific Bill Adjustments - GA/CBR for Class A/B Customers for Part of the Year		($71,854)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2016 actuals reported in Horizon Utilities RZ RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016.

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 37 below summarizes the deferral and variance rate riders by class.

Table 37 – 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, 2016		CBR B Rate Rider Class B Consumer Jan 1 - Dec 31, 2016	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
RESIDENTIAL	(0.0009)				(0.0018)		(0.00005)	
GENERAL SERVICE <50 KW	(0.0009)				(0.0018)		(0.00005)	
GENERAL SERVICE >50 KW		0.1075		(0.4519)	(0.0018)			(0.01721)
LARGE USE (1)		0.1412		(0.6689)	(0.0018)			(0.02598)
LARGE USE (2)		0.1628		(0.5507)	0.0000			0.00000
UNMETERED & SCATTERED LOADS	(0.0009)				(0.0018)		(0.00005)	
SENTINEL LIGHTS		(0.3376)			(0.0018)			(0.01728)
STREET LIGHTING		(0.3354)			(0.0018)			(0.01717)

Alectra Utilities requests disposition of the Horizon Utilities RZ adjusted Group 1 balances of ($7,370,171), identified in Table 36, through the rate riders identified in Table 37 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 2018 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.

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 ($0.71)/month or (0.65%) on total bill.

Settlement Process with the IESO – Horizon Utilities RZ

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 38 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 38 – 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.

Class B non-RPP Customers: Class B non-RPP customers are billed by 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 39 below.

Table 39 – 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 LRAMVA account resulting from its Conservation and Demand Management ("CDM") activities in 2013 through 2015 in the Horizon Utilities RZ. The total amount requested for disposition is a debit of $1,281,317 including forecasted carrying charges of $46,276 through to December 31, 2017. Horizon Utilities' actual savings from CDM activities for 2013 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Horizon Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR application (EB-2014-0002). In that proceeding, the Board approved Horizon Utilities' request to recover lost revenues from CDM activities in 2011 and 2012.

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 $1,281,317, 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 11. 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:

1. Horizon Utilities RZ has used the most recent input assumptions available at the time of the program evaluation when calculating the lost revenue amount; and

2. Horizon Utilities RZ 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 2011 to 2014 and 2015 are filed as Attachments 12 and 13, respectively.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2016. Alectra Utilities proposes to dispose of its 2016 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 2016 balances as mentioned previously.

Alectra Utilities is seeking recovery of lost revenues for the Horizon Utilities RZ for the period January 1, 2013 to December 31, 2015 resulting from the following:

1. 2011 and 2012 LRAM persistence in 2013 and 2014;
2. Incremental savings from IESO-funded CDM programs implemented in 2013 and 2014, including persistence through 2014; and
3. Incremental savings from IESO-funded CDM programs implemented in 2015.

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 40 identified below.

Table 40 – Distribution Volumetric Rates – Horizon Utilities RZ

Year	Residential	GS<50 kW	General Service 50 to 4,999 kW	Large Use	Large Use	Street Lighting
	kWh	kWh	kW	kW	kWh	kW
2011	$0.0143	$0.0085	$2.0506	$1.3575	$0.0000	$6.2205
2012	$0.0142	$0.0083	$2.0329	$1.3344	$0.0000	$6.1289
2013	$0.0144	$0.0084	$2.0576	$1.3507	$0.0000	$6.2093
2014	$0.0146	$0.0085	$2.0897	$1.3718	$0.0000	$6.3064
2015	$0.0155	$0.0101	$2.4286	$1.3465	$0.2246	$7.4960

Horizon Utilities' LRAMVA threshold approved in its 2011 Cost of Service Application (EB-2010-0131) is used as the comparator against actual savings for the lost revenue calculation for 2011 to 2014. Horizon Utilities filed a Custom IR Application (EB-2014-0002) with the OEB on April 16, 2014. The Board approved Horizon Utilities' new load forecast and LRAMVA threshold for 2015, which was used as the comparator against actual savings for the lost revenue calculation for 2015. Horizon Utilities' LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 41 identified below.

Table 41 – LRAMVA Thresholds – Horizon Utilities RZ

Year	LRAMVA Threshold	Residential	GS<50 kW	GS>50 to 4,999 kW
		kWh	kWh	kW
2011		0	0	0
2012	2011	12,575,666	4,393,315	30,468
2013	2011	12,575,666	4,393,315	30,468
2014	2011	12,575,666	4,393,315	30,468
2015	2015	3,350,520	928,649	34,728

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2012 to December 31, 2015 for the Horizon Utilities RZ in the LRAMVA work form using the OEB's annual prescribed interest rates of 1.47% to March 31, 2015 and 1.1% thereafter as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $1,281,317, representing a principal balance of $1,235,041 and carrying charges of $46,276.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 42 and 43 below for the Horizon Utilities RZ, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 42 – LRAMVA Totals by Rate Class – Horizon Utilities RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$425,370	$13,750	$439,120
GS<50 kW	kWh	$317,639	$9,909	$327,548
GS 50 kW to 4,999 kW	kW	$254,164	$12,571	$266,735
Large Use (1)	kW	$144,605	$7,5177	$152,122
Large Use (2)	kWh	$9,024	$245	$9,268
Street Lighting	kW	$84,239	$2,284	$86,524
Total		**$1,235,041**	**$46,276**	**$1,281,317**

Table 43 – LRAMVA by Year and Rate Class – Horizon Utilities RZ

Description	Residential	GS<50 kW	General Service 50 to 4,999 kW	Large Use	Large Use	Street Lighting	Total
	kWh	kWh	kW	kW	kWh	kW	
2012 Actuals	$83,536	$16,751	$66,163	$30,888	$0	$0	$197,338
2012 Forecast	($178,574)	($36,465)	($61,938)	$0	$0	$0	($276,977)
2014 LRAM Balance	**($95,038)**	**($19,714)**	**$4,225**	**$30,888**	**$0**	**$0**	**($79,639)**
2013 Actuals	$265,985	$75,302	$177,908	$51,322	$0	$0	$570,517
2013 Forecast	($181,090)	($36,904)	($62,691)	$0	$0	$0	($280,684)
2014 LRAM Balance	**$84,895**	**$38,399**	**$115,217**	**$51,322**	**$0**	**$0**	**$289,832**
2014 Actuals	$471,425	$115,386	$229,231	$60,520	$0	$0	$876,562
2014 Forecast	($183,605)	($37,343)	($63,669)	$0	$0	$0	($284,617)
2014 LRAM Balance	**$287,820**	**$78,043**	**$165,562**	**$60,520**	**$0**	**$0**	**$591,946**
2015 Actuals	$199,626	$230,290	$53,501	$1,874	$9,024	$84,239	$578,555
2015 Forecast	($51,933)	($9,379)	($84,340)	$0	$0	$0	($145,653)
2015 LRAM Balance	**$147,693**	**$220,911**	**($30,839)**	**$1,874**	**$9,024**	**$84,239**	**$432,902**
Carrying Charges	**$13,750**	**$9,909**	**$12,571**	**$7,517**	**$245**	**$2,284**	**$46,276**
Total LRAMVA Balance	**$439,120**	**$327,548**	**$266,735**	**$152,122**	**$9,268**	**$86,524**	**$1,281,317**

The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are identified in Table 44 below and included in Tab “8. Calculation of Def-Var RR” in the IRM Model.

1 **Table 44 – LRAMVA Rate Riders – Horizon Utilities RZ**

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.00	$0.0003	kWh
General Service under 50 kW	$0.00	$0.0006	kWh
General Service 50 to 4999 kW	$0.00	$0.0545	kW
Large Use (1)	$0.00	$0.2969	kW
Large Use (2)	$0.00	$0.0049	kW
Unmetered	$0.00	$0.0000	kWh
Sentinel Lights	$0.00	$0.0000	kW
Street Lighting	$0.00	$0.9758	kW

Summary of Bill Impacts

A summary of bill impacts for the typical customer by rate class is presented in Tables 45 to 47 below. Attachment 3 provides a detailed summary of the bill impacts for each customer class for 2018.

Table 45 – Distribution Bill Impacts by Rate Class – Horizon Utilities RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ (1.68)	(5..94)%
GS<50	kWh	2,000	$ (2.40)	(3.68)%
GS>50	kW	250	$ (2.80)	(0.27)%
Large User	kW	5,000	$ 898.45	2.92%
Large User with Dedicated Assets	kW	20,000	$ (64.42)	(0.53)%
Street Lighting	kW	4,974	$ (3,694.87)	(3.49)%

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

Table 46 – 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	2018 vs. 2017	
			$	%
Residential	kWh	750	$ (0.44)	(1.49)%
GS<50	kWh	2,000	$ 0.70	1.04%
GS>50	kW	250	$ (235.52)	(24.27)%
Large User	kW	5,000	$ 6,002.35	25.73%
Large User with Dedicated Assets	kW	20,000	$ 19,325.58	(133.82)%
Street Lighting	kW	4,974	$ (7,017.65)	(6.73)%

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

Table 47 – Total Bill Impacts by Rate Class (before HST) – Horizon Utilities RZ

Total Bill Impacts				
Customer Class	**Billing Units**	**Average Monthly Volume**	**2018 vs. 2017**	
			$	**%**
Residential	kWh	750	$ (0.22)	(0.21)%
GS<50	kWh	2,000	$ 1.22	0.44%
GS>50	kW	250	$ (210.72)	(1.36)%
Large User	kW	5,000	$ 6,570.76	1.87%
Large User with Dedicated Assets	kW	20,000	$ 21,599.21	1.67%
Street Lighting	kW	4,974	$ (6,629.89)	(1.96)%

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

CONCLUSION

Alectra Utilities' proposed 2018 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 and 2017 Annual Filings.

Alectra Utilities' Specific Service Charges for the Horizon 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, 2018. This application impacts customers in the City of Brampton.

Alectra Utilities has completed the IRM Model for the Brampton RZ provided by the OEB and will update the Application to include the 2018 IRM Rate Generator Model ("2018 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 14, 2016, 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 14, 2016.

Alectra Utilities also applies for incremental capital funding for the Enersource RZ in accordance with the OEB's: *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications* issued July 14, 2016 ("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 Brampton RZ:

a. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;

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, 2016, 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. An adjustment to the retail transmission service rates effective January 1, 2018;

g. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers; and

h. Current (i.e., 2017) rates provided in Attachment 14 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

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 2018 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 4, 2016 (the "August 2016 Report"). The August 2016 Report placed Hydro One Brampton in Group III for the purpose of calculating stretch factors for 2017.

Inflation Factor

The Industry Specific Inflation Factor for 2018 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor for the Brampton RZ published for 2017 IRM filers, i.e., 1.9%, as a proxy for 2018.

Alectra Utilities will update the IRM Model with the 2018 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 1.60%, is identified in Table 48 below.

Table 48 – Calculation of Price Cap Index – Brampton RZ

Factor	%
Inflation Factor	1.90%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.3%
Price Cap Index	**1.6%**

The Price Cap Index of 1.6% has been applied to Brampton RZ 2017 Service Charge and Distribution Volumetric Rate by rate class to determine the 2018 Service Charges and Distribution Volumetric Rates. The Alectra Utilities Proposed Tariff of Rates and Charges for the Brampton RZ is filed as Attachment 15.

The Ontario government has released the OFHP. The OFHP: i) extended the payback period for items within the Global Adjustment ("GA"), and ii) transferred the funding of certain support programs, such as the Ontario Energy Support Program ("OESP") from the electricity rate base to the tax base. A portion of the bill reduction announced in the OFHP, achieved through a reduction in Regulated Price Plan ("RPP") prices, in addition to the removal of the OESP charge of $0.0011/kWh, took effect on May 1, simultaneous with the RPP changes. The final portion of the bill reduction, achieved through a further reduction in RPP prices, in addition to a reduction to the Rural and Remote Rate Protection ("RRRP") charge from $0.0021/kWh to $0.0003/kWh, took effect on July 1. Accordingly, Alectra Utilities has incorporated the removal of the OESP and reduction to the RRRP charge in the Alectra Utilities Proposed Tariff of Rates and Charges for the Brampton RZ.

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[9]: "[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[10], 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 has incorporated the third year transition adjustment in its proposed rates for the Brampton RZ for 2018. 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.

[9] EB – 2015-0078, p 8.

[10] EB – 2016-0080, p.14.

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 Brampton RZ the Residential monthly service charge increase of $3.42 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, 2016 for the Brampton RZ. The method used for purposes of this analysis is consistent with the methodology used in Hydro One Brampton's last EDR application (EB-2016-0080).

2. Through the query, Alectra Utilities obtained Brampton RZ data for 2016 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 2016. 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, 2016 is 146,067. 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 2016 from lowest to highest and 10% of the total number of customers above 50 kWh was determined to be the 14,607th lowest usage customer as follows: 10% of 146,067 Residential Customers = 14,607.

Alectra Utilities has provided in Table 49 below the bill impact for the Brampton RZ for a Residential customer that consumes 361 kWh, monthly. The fixed monthly service charge increased by $3.42 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 5.13%.

Table 49 – 10th Consumption Percentile Residential Customer Bill Impact (361 kWh) – Brampton RZ

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 361 kWh
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	$ 17.64	1	$ 17.64	$ 21.06	1	$ 21.06	$ 3.42	19.39%
Distribution Volumetric Rate	$ 0.0080	361	$ 2.89	$ 0.0041	361	$ 1.48	$ (1.41)	-48.75%
Fixed Rate Riders	$ -	1	$ -	$ 0.23	1	$ 0.23	$ 0.23	
Volumetric Rate Riders	$ 0.0006	361	$ 0.22	$ -	361	$ -	$ (0.22)	-100.00%
Sub-Total A (excluding pass through)			$ 20.74			$ 22.77	**$ 2.03**	**9.76%**
Line Losses on Cost of Power	$ 0.0822	12	$ 1.01	$ 0.0822	12	$ 1.01	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0035	361	$ (1.26)	-$ 0.00103	361	$ (0.37)	$ 0.89	-70.57%
Low Voltage Service Charge	$ -	361	$ -	$ -	361	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21.28**			**$ 24.20**	**$ 2.92**	**13.71%**
RTSR - Network	$ 0.0074	373	$ 2.76	$ 0.0075	373	$ 2.80	$ 0.04	1.35%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	373	$ 2.13	$ 0.0057	373	$ 2.13	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 26.17**			**$ 29.13**	**$ 2.95**	**11.29%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	373	$ 1.34	$ 0.0036	373	$ 1.34	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	373	$ 0.11	$ 0.0003	373	$ 0.11	$ -	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	235	$ 15.25	$ 0.0650	235	$ 15.25	$ -	0.00%
TOU - Mid Peak	$ 0.0950	61	$ 5.83	$ 0.0950	61	$ 5.83	$ -	0.00%
TOU - On Peak	$ 0.1320	65	$ 8.58	$ 0.1320	65	$ 8.58	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 57.54**			**$ 60.49**	**$ 2.95**	**5.13%**
HST	13%		$ 7.48	13%		$ 7.86	$ 0.38	5.13%
8% Provincial Rebate	-8%		$ (4.60)	-8%		$ (4.84)	$ (0.24)	5.13%
Total Bill on TOU			**$ 60.42**			**$ 63.52**	**$ 3.10**	**5.13%**

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 14, 2016, the OEB issued its Decision and Order in respect of the 2016 Uniform Transmission Rates ("UTRs") (EB-2015-0311). At the time of this filing, 2017 UTRs were not available. 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 page10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 50 below.

Table 50 – Current Board-Approved UTRs and STRs – Brampton RZ

UTRs	$
Network Service Rate	$3.66
Line Connection Service Rate	$0.87
Transformation Connection Service Rate	$2.02

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 2015 to 2016 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, 2016, in the amount of ($8,892,780) have been adjusted for the following items to determine the amount for disposition of ($5,732,154), as identified in Table 4, 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 must be 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. Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;

For the Brampton RZ, an adjustment of $803,139 and ($1,619,355) has been made to Account 1588 and Account 1589 respectively, to reflect RPP settlement true-up claims for 2016 that were settled in 2017. These amounts have been entered into the IRM model, Tab “3. Continuity Schedule” Column “Principal Adjustment during 2016”. See Table 51 below for a summary of this adjustment.

- 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 51 – Group 1 Account Balances for Disposition – Brampton RZ

Description	Amount
Group 1 Account Balances as of December 31, 2016	**($8,892,780)**
Subtract 2017 Annual Filing Disposition (EB-2016-0080) - Recovery from Customers	($4,037,909)
RPP Settlement True-up Claims Adjustment	($816,217)
Add Projected Carrying Charges	($61,066)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($5,732,154)**

Alectra Utilities has computed the disposition threshold for the Brampton RZ, based on the adjusted Group 1 balances, to be ($0.0014)/kWh, as identified in the table below. Alectra Utilities requests disposition of its Group 1 account balances for the Brampton RZ in this IRM application.

Table 52 - Calculation of Disposition Threshold – Brampton RZ

Description	Account	Amount
Low Voltage	1550	$659,204
Smart Meter Entity Charge	1551	($181,649)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	$876,883
RSVA - Wholesale Market Service Charge excluding CBR	1580	($13,184,733)
RSVA - Retail Transmission Network Charge	1584	($976,995)
RSVA - Retail Transmission Connection Charge	1586	$988,852
RSVA – Power	1588	($6,464,773)
RSVA - Global Adjustment	1589	$9,652,924
Disposition and Recovery/Refund of Regulatory Balances	1595	($262,495)
Group 1 Account Balances as of December 31, 2016		**($8,892,780)**
Subtract 2017 Annual Filing Disposition (EB-2016-0002) - Refund to Customers		($4,037,909)
RPP Settlement True-up Claims Adjustment		($816,217)
Add Projected Carrying Charges		($52,088)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($5,732,154)**
2016 kWhs		4,030,218,510
Threshold Test $/kWh		**($0.0014)**

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 2016 RRR for the Brampton RZ, section 2.1.7 as identified in Table 53 below. Alectra Utilities confirms that the last Board approved balance of ($4,037,909) for Hydro One Brampton has been transferred to Account 1595 (as identified in Hydro One Brampton's 2017 IRM Application (EB-2016-0080)). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2016 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 1.10% was used to calculate forecasted interest for 2017. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 53 – Deferral and Variance Account Reconciliation – Brampton RZ

Account Description	Account	Principal Amounts as of Dec 31, 2016	Carrying Charges to Dec 31, 2016	Principal Disposition during 2017 - instructed by Board EB-2016-0080	Interest Disposition during 2016 - instructed by Board EB-2016-0080	Projected Carrying Charges to Dec 31, 2017	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims Adjustment	Projected Carrying Charges to December 31, 2017	Total Disposition
Group 1 Accounts:										
Low Voltage	1550	649,664	9,540	(402,447)	(8,296)	2,719	251,180			251,180
Smart Meter Entity Charge	1551	(178,812)	(2,838)	118,862	2,600	(659)	(60,847)			(60,847)
RSVA - Wholesale Market Service Charge - CBR B	1580	867,074	9,809	(964,946)	(11,427)	(1,077)	(100,566)			(100,566)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(13,055,982)	(128,751)	9,329,740	111,604	(40,989)	(3,784,378)			(3,784,378)
RSVA - Retail Transmission Network Charge	1584	(976,245)	(750)	496,717	(2,769)	(5,275)	(488,321)			(488,321)
RSVA - Retail Transmission Connection Charge	1586	972,741	16,112	(417,474)	(13,891)	6,108	563,595			563,595
RSVA - Power	1588	(6,334,349)	(130,424)	5,313,869	119,678	(11,225)	(1,042,451)	803,139	8,835	(230,478)
Sub-total not including RSVA Power Global Adjustment		(18,055,909)	(227,300)	13,474,321	197,498	(50,397)	(4,661,787)	803,139	8,835	(3,849,814)
RSVA - Power Global Adjustment	1589	9,459,126	193,799	(9,450,912)	(182,998)	90	19,105	(1,619,355)	(17,813)	(1,618,064)
Total including RSVA Power Global Adjustment		(8,596,783)	(33,502)	4,023,409	14,500	(50,307)	(4,642,683)	(816,217)	(8,978)	(5,467,878)
Disposition and Recovery/Refund of Regulatory Balances (2014) - (IRM 14)	1595	262,995	(106,528)			2,893	159,360			159,360
Disposition and Recovery/Refund of Regulatory Balances (2015) - (COS 15)	1595	(424,904)	5,941			(4,674)	(423,637)			(423,637)
Total 1595		(161,909)	(100,587)	-	-	(1,781)	(264,277)	-	-	(264,277)
Total Group 1		**(8,758,692)**	**(134,089)**	**4,023,409**	**14,500**	**(52,088)**	**(4,906,960)**	**(816,217)**	**(8,978)**	**(5,732,154)**
Total Amount for Disposition		**(8,758,692)**	**(134,089)**	**4,023,409**	**14,500**	**(52,088)**	**(4,906,960)**	**(816,217)**	**(8,978)**	**(5,732,154)**

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 three Brampton RZ customers, who qualified as Class A customers effective July 1, 2016 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, 2016; and paid GA and CBR as Class A customers from July 1, 2016 to December 31, 2016 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, 2016 to June 30, 2016).

There was one Alectra Utilities customer in the Brampton RZ, who ceased to qualify as a Class A customer effective July 1, 2016, under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). This customer paid GA and CBR as a Class A customer up to and including June 30, 2016; and paid GA and CBR as a Class B customer from July 1, 2016 to December 31, 2016.

This customer should be allocated only the portion of the GA account balance which accrued after its reclassification to a Class B customer (i.e. from July 1, 2016 to December 31, 2016).

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 54 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 ($1,618,064), of which ($1,587,067) will be disposed of via rate riders; further, ($23,528) and ($7,469) will be disposed of via specific bill adjustments to the three new Class A customers and one new Class B customer 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 total bill adjustments of $366.

The total CBR balance to be disposed of is $100,566, of which the amount of $99,562 will be disposed of via rate riders; further ($763) and ($242) will be disposed of via specific bill adjustments to the three new Class A customers and one new Class B customer 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 total bill adjustments of ($1,005).

Alectra Utilities requests disposition of its GA balance of ($30,997) and its CBR balance of ($1,005) related to its three new Class A customers and one new Class B customer for the Brampton RZ (effective July 1, 2016) respectively, through the bill adjustments identified in the IRM Model.

Table 54 –Disposition of GA and CBR Balances – Brampton RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($1,587,067)
Global Adjustment - New Class A Customers July 1/2016	($23,528)
Global Adjustment - New Class B Customers July 1/2016	($7,469)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**($1,618,064)**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($99,562)
Capacity Based Recovery - New Class A Customers July 1/2016	($763)
Capacity Based Recovery - New Class B Customers July 1/2016	($242)
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($100,566)**

A summary of the rate riders applicable to each group of customers is identified in Table 55 below.

Table 55 – 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, 2016 - Dec 31, 2016)	x	x			
Class B non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class A (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers					
Class B non-RPP (Jan 1, 2016 - Dec 31, 2016) 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 and the remaining balance in Account 1595 related to Hydro One Brampton’s 2017 IRM Application (EB-2016-0080).

Class A customers (who were Class A from January 1 – December 31, 2016) 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 2016) 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 2016) 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, 2016) 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 56 below. The amount to be disposed of by rate rider is ($5,700,152) and the amount to be disposed of via customer specific bill adjustments is ($32,002) (($30,997) GA and ($1,005) CBR).

Table 56 – Group 1 Disposition by Customer Group – Brampton RZ

Description	Account	Amount
Low Voltage	1550	$251,180
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($60,847)
Retail Transmission Network Charge	1584	($488,321)
Retail Transmission Connection Charge	1586	$563,595
Disposition and Recovery/Refund of Regulatory Balances	1595	($264,277)
All Customers - DVA Rate Rider 1		**$1,331**
Power	1588	($230,478)
Wholesale Market Service Charge excluding CBR	1580	($3,784,378)
All Customers ex WMPs - DVA Rate Rider 2		**($4,014,856)**
Wholesale Market Service Charge - CBR Class B	1580	($99,562)
Wholesale Market Service Charge - New Class A/B Customers July 1/2016		($1,005)
All Class B Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($100,566)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2016 -Dec 31/2016	1589	($1,587,067)
Global Adjustment - New Class A/B Customers July 1/2016	1589	($30,997)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**($1,618,064)**
Total (Repayment to)/Recovery from Customers		**($5,732,154)**
Disposition via Rate Rider		($5,700,152)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2016		($30,997)
Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2016		($1,005)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2016 actuals, reported in the Hydro One Brampton's ' 2016 RRRs filed by Alectra Utilities, have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016.

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 57 below summarizes the deferral and variance account rate riders by customer class.

Table 57 – 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, 2016		CBR B Rate Rider Class B Consumer Jan 1 - Dec 31, 2016	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
RESIDENTIAL	(0.0010)				(0.0009)		(0.00003)	
GENERAL SERVICE <50 KW	(0.0010)				(0.0009)		(0.00003)	
GENERAL SERVICE >50 KW		0.0055		(0.3604)	(0.0009)			(0.01029)
GENERAL SERVICE >700 KW		0.0066		(0.4199)	(0.0009)			(0.01143)
LARGE USE		(0.5487)			(0.0009)			(0.01493)
UNMETERED & SCATTERED LOADS	(0.0010)				(0.0009)		(0.00003)	
STREET LIGHTING		(0.3199)			(0.0009)			(0.00961)
EMBEDDED DISTRIBUTOR	(0.0009)				(0.0009)		(0.00003)	
DISTRIBUTED GENERATION [DGEN]	(0.0009)				(0.0009)		(0.00003)	

Alectra Utilities requests disposition of its adjusted Group 1 balances of ($5,732,154) for the Brampton RZ, identified in Table 56, through the rate riders identified in Table 57, 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.

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 ($0.77)/month or (0.72%) on the total bill.

Alectra Utilities understands that OEB staff are testing a new Global Adjustment Analysis work form for the 2018 IRM process. At the time of this filing, a final work form is not available. Alectra Utilities anticipates providing the completed workform once it is released by the OEB.

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 58 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 58 – 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 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

Class A Customers: 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 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. <u>True-up adjustment to the RPP settlement amount</u>

- 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.

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 $117,963 in 2018 or $9,830 per month from all provincial ratepayers, as identified in Table 59 below for the Brampton RZ.

Table 59: Green Energy Plan Rate Protection Benefit and Charge in 2017– Brampton RZ

	2018	
Description	**Yearly**	**Monthly**
Renewable Enabling Improvement Investments	$ 91,464	$ 7,622
Renewable Expansion Investments	$ 26,499	$ 2,208
Total Recovery:	**$ 117,963**	**$ 9,830**

Disposition of LRAM Variance Account

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.

In this application, Alectra Utilities is not applying for rate riders associated with its 2016 LRAMVA account balances in the Brampton RZ. As per the Board's Decision and Order in the Hydro One Brampton 2017 IRM Application, the Board approved Hydro One Brampton's request to dispose of its LRAMVA balances as at December 31, 2015, consisting of lost revenues from CDM programs in 2013, 2014 and 2015, and the related persistence through this period. The Board's Chapter 3 Filing Requirements requires distributors to provide a statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation and include a copy of this report. The IESO has not issued the Final Annual Verified Results for 2016. Therefore, Alectra Utilities proposes that it will dispose of the Brampton RZ 2016 LRAMVA balance in a future rate proceeding.

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 a legislated tax change impact. Alectra Utilities corporate tax rate is 26.50% as it was from Hydro One Brampton; it is not expected to change. Therefore, there is no shared tax savings in this application.

Incremental Capital Module

Overview

Hydro One Brampton filed a DSP for 2015 to 2019 in its 2015 Cost of Service Application (EB-2014-0083). Hydro One Brampton's DSP was developed based on established asset management and capital expenditure planning practices that include investment portfolio optimization, work execution and continuous improvement.

The DSP was built on the strategy of centralizing key decision making in order to maximize the long-term effectiveness of investments while maintaining performance levels. The DSP also considered economic, service quality, community safety, legal and reputational risks. Hydro One Brampton and Intervenors filed a partial settlement proposal (the "Brampton Settlement Proposal") with the OEB on October 9, 2014 for the 2015 Cost of Service Application. On December 18, 2014, the OEB advised that it had accepted the Settlement Proposal. The parties to the Settlement Proposal agreed to a capital budget of $37.9MM in 2015.

Alectra Utilities is seeking Board approval for incremental capital funding for its Brampton RZ for 2018, through distribution rate riders as identified in Attachment 18 Alectra Utilities has capital investment needs for the Brampton RZ that are not funded through existing distribution rates. As previously stated, the Brampton RZ is on Price Cap IR for the purpose of setting 2018 electricity distribution rates and therefore, the ICM is available to Alectra Utilities for the Brampton RZ.

The Hydro One Brampton DSP was designed to address capital expenditures across the four prescribed OEB categories: system access, system service, system renewal, and general plant. System access investments include feeder expansion and reinforcement projects to support land development. System renewal investments include sustainment and asset replacement programs and projects required to maintain acceptable levels of existing asset performance. System service investments include distribution system upgrades and modifications to address expected changes in system use by customers. General plant investments are necessary to meet business support requirements for operations.

Hydro One Brampton's Asset Management Process is the foundation of the DSP. The objective of the asset management process is to invest in and maintain assets to achieve the lowest long-term cost of ownership while adhering to accepted design standards, construction codes and requirements, system performance targets and prescribed manufacturing specifications. The key elements of the asset management process include: identification of needs based on multiple inputs; determination of appropriate technical alternatives; development of business cases to address identified needs; rate and customer impact assessment; execution of planned projects; and programs according to the business plan and continuous improvement.

Alectra Utilities provides a summary of its historical and proposed capital investments by category in Table 60 below for the Brampton RZ.

Table 60: Capital Expenditures by Category from 2013 to 2020 ($000s) – Brampton RZ

Category	Actual 2013	Actual 2014	COS 2015	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
System Access	$11,970	$18,399	$17,759	$21,333	$20,792	$15,378	$20,751	$13,560	$20,333
System Renewal	$12,123	$9,073	$8,880	$15,674	$8,144	$11,980	$12,855	$9,677	$10,960
System Service	$1,475	$715	$1,485	$1,779	$826	$1,812	$529	$575	$682
General Plant	$4,505	$3,697	$9,741	$3,785	$996	$11,048	$3,934	$16,332	$11,098
Total	**$30,073**	**$31,885**	**$37,865**	**$42,571**	**$30,757**	**$40,218**	**$38,069**	**$40,144**	**$43,073**

Alectra Utilities provides an explanation of capital expenditures for the Brampton RZ from 2013 to 2020 by investment category below. Alectra Utilities has filed at Attachment 22, details by project for the proposed 2018 capital spending plan.

System Access

System Access investments are comprised of projects outside of Alectra Utilities' control for the Brampton RZ, that are required to meet customer service obligations in accordance with the DSC. These projects include: connecting new customers; metering; connecting new subdivisions; and relocating system plant for roadway reconstruction work. Alectra Utilities uses an economic evaluation methodology prescribed in the DSC for the Brampton 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. The increase in capital expenditures in 2018 and 2020 is due to forecasted CCRA payments related to Pleasant TS and Goreway TS respectively. System

Access actual and forecast capital expenditures from 2013 to 2020 are provided in Table 61 below.

Table 61 – System Access Capital Expenditures ($000s) – Brampton RZ

Category	Actual 2013	Actual 2014	COS 2015	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
New Connections & Subdivisions	$7,065	$4,950	$4,782	$3,948	$10,001	$4,156	$3,340	$3,675	$3,526
Road Authority	$2,883	$4,440	$4,555	$2,464	$6,296	$3,721	$3,751	$3,893	$3,548
Metering	$1,423	$1,616	$1,654	$1,294	$1,449	$1,569	$1,587	$1,531	$1,600
Dx Expansion	$565	$3,664	$4,172	$4,273	$2,594	$5,192	$5,149	$4,462	$4,909
RGEN New Connections	$0	$0	$0	$1,734	$452	$0	$0	$0	$0
Other Misc	$35	$3,729	$2,596	$7,621	$0	$741	$6,923	$0	$6,750
System Access	**$11,970**	**$18,399**	**$17,759**	**$21,333**	**$20,792**	**$15,378**	**$20,751**	**$13,560**	**$20,333**

System Renewal

System Renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets. System Renewal actual and forecast capital expenditures from 2013 to 2020 are provided in Table 62 below.

Table 62 – System Renewal Capital Expenditures ($000s) – Brampton RZ

Category	Actual 2013	Actual 2014	COS 2015	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
UG Lines Planned Asset Replacement	$4,917	$5,061	$2,664	$3,210	$1,740	$5,229	$6,048	$5,236	$4,853
Distribution Lines - Emergency/Reactive	$2,427	$793	$826	$1,608	$1,788	$668	$738	$801	$864
Overhead - Lines Planned Asset Replacement	$712	$574	$309	$610	$1,758	$849	$873	$937	$1,067
4.16 to 27.6 kV Conversion	$952	$1,205	$1,207	$3,341	$11	$1,535	$1,900	$1,530	$1,300
Stations/P&C-Planned Replacement	$2,610	$1,088	$2,955	$340	$1,199	$134	$1,677	$107	$1,738
Other Misc	$505	$352	$211	$915	$1,240	$2,577	$778	$637	$712
Metering	$0	$0	$709	$5,651	$407	$988	$840	$430	$427
System Renewal	**$12,123**	**$9,073**	**$8,880**	**$15,674**	**$8,144**	**$11,980**	**$12,855**	**$9,677**	**$10,960**

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. System Service actual and forecast capital expenditures from 2013 to 2020 are provided in Table 63 below.

Table 63 – System Service Capital Expenditures ($000s) - Brampton RZ

Category	Actual 2013	Actual 2014	COS 2015	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
Station Protection Upgrades	$0	$0	$0	$932	$11	$1,314	$0	$0	$0
Reliability	$931	$309	$928	$635	$243	$149	$149	$155	$162
Distribution Automation	$544	$406	$557	$212	$572	$350	$380	$420	$520
System Service	**$1,475**	**$715**	**$1,485**	**$1,779**	**$826**	**$1,812**	**$529**	**$575**	**$682**

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. General plant actual and forecast capital expenditures from 2013 to 2020 are provided in Table 64 below.

Table 64 – General Plant Capital Expenditures ($000s) - Brampton RZ

Category	Actual 2013	Actual 2014	COS 2015	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
CIS	$0	$0	$0	$0	$0	$0	$0	$14,096	$8,396
ERP System	$0	$0	$5,065	$0	$0	$6,805	$0	$0	$0
IT Hardware	$363	$344	$344	$142	$139	$239	$726	$243	$245
IT Software	$193	$0	$0	$908	$253	$384	$311	$320	$344
Facilities	$1,157	$1,217	$1,458	$441	$126	$645	$178	$188	$107
Fleet	$2,041	$1,395	$2,393	$2,079	$136	$2,675	$2,402	$1,152	$1,662
Tools	$143	$141	$0	$171	$95	$143	$155	$163	$169
Other Misc	$608	$600	$482	$44	$246	$157	$162	$169	$175
General Plant	**$4,505**	**$3,697**	**$9,741**	**$3,785**	**$996**	**$11,048**	**$3,934**	**$16,332**	**$11,098**

Connection and Cost Recovery Agreement

Alectra Utilities has a connection and cost recovery agreement ("CCRA") payment of $6.8MM due to Hydro One Networks Inc. ("HONI") in the Brampton RZ in 2018. The payment relates to the Pleasant Transformer Station ("TS") ten year true up. The payment is non-discretionary and is above the basis on which rates were set. Alectra Utilities is seeking recovery through an ICM for the Brampton RZ for the CCRA payment. Alectra Utilities utilized HONI's Transmission Contribution Model, a discounted cash flow model, to determine the forecasted true up payment.

Under the Transmission System Code ("TSC"), and consequently the CCRA, Alectra Utilities is required to provide HONI with an initial capital contribution based on the difference between the total capital cost of constructing the TS and a projection of transformation revenue (the "HONI Revenue") earned on the conveyance of electricity through the TS (Attachment 20). The difference represents a contingent debt obligation of Alectra Utilities based on the extent to which historical actual and forecast HONI Revenue during the CCRA term is less than the amount of HONI revenue projected as a basis for the determination of the initial capital contribution. Conversely, Alectra Utilities is entitled to a rebate of the initial capital contribution based on the extent to which historical actual and forecast HONI Revenue during the CCRA term is greater than the amount of HONI Revenue projected as a basis for the determination of the initial capital contribution.

In 2005, a need for new transformer capacity was identified to meet existing and future demand growth in the North-West area of Brampton. The proposed station expansion was designed to offload Pleasant TS T5/T6 that was exceeding transformer capacity. In 2008, the construction of Pleasant TS T7/T8 was completed and the additional expansion of the Pleasant TS was put into service. A copy of Pleasant TS Expansion executed CCRA is provided in Attachment X.

As per the TSC, and consequently CCRA for low risk connections, HONI is required to complete a true-up on the five, ten and if applicable, fifteen year anniversaries to settle for demand forecast excesses or shortfalls. Based on a review of the CCRA with HONI for Pleasant TS expansion of T7/T8 on the five year anniversary, Hydro One Brampton Networks Inc. and HONI determined a shortfall of revenue to HONI versus the forecasted Initial Capital Contribution. The five year true-up CCRA shortfall payment in accordance of the CCRA for the Pleasant TS T7/T8 expansion was completed in 2015 in the amount of $7.086 MM. The five-year true-up revenue shortfall was largely due to the government-driven conservation initiatives, natural conservation and economic downturn that occurred in 2008 that have resulted in historical actual load being lower than forecasted load.

The ten-year anniversary true-up for Pleasant TS expansion is due in 2018. Alectra estimates a shortfall of revenue to HONI versus the forecasted Initial Capital Contribution and the five-year true-up settlement.

Request for financial settlement is anticipated from HONI in 2018 in the amount of $6.80MM, with the final amount and payment terms negotiated between HONI and Alectra at that time. The revenue shortfall continues largely due to government-driven conservation initiatives, natural conservation and an impact of economic downturn that occurred in 2008 (and which has not been overcome) which have resulted in historical actual load being lower than forecasted load.

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 18, 2014 (the "ACM Report").

These criteria are discussed in detail below.

The OEB's Capital Module for ACM and ICM ("ICM Model") for the Brampton RZ is included as Attachment 18.

<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:

$$\textit{Threshold Value}\,(\%) = 1 + [(\frac{RB}{d}) \times (g + PCI \times (1 + g))]) \times ((1 + g) \times (1 + PCI)^{n-1} + 10\%$$

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 Brampton RZ using the Board-approved rate base and depreciation amounts from its 2015 Cost of Service Application (EB-2014-0083), a price cap index ("PCI") of 1.6% and a growth rate of 1.66%.

The PCI of 1.6% is a placeholder to be updated with the OEB's approved PCI for 2018 when it is available. It is based on inflation of 1.9% less a productivity factor of 0% and a stretch factor of 0.3% as identified in Table 65 below.

The growth rate of 1.66% has been calculated in accordance with the ACM Report and is equal to the increase in revenue based on the 2016 actual billing determinants for the Brampton RZ, divided by 2015 OEB approved billing determinants, using 2016 approved rates. The growth rate calculation is identified in Table 65 below.

Table 65 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula approved in the ACM Report. The threshold value for 2018 is 203% which results in a threshold capital expenditure value of $30,955,867.

Table 65 – Threshold Capital Expenditure Calculation – Brampton RZ

Description	Amount
Inflation	1.90%
Less: Productivity Factor	
Less: Stretch Factor	-0.30%
Price Cap Index	1.60%
2016 Volumes @ 2016 Rates	$71,972,713
2015 Volumes @ 2016 Rates	$70,794,590
Growth Factor	1.66%
Year	2018
# Years since rebasing	3
Price Cap Index	1.60%
Growth Factor	1.66%
Dead Band	10%
Rate Base	$404,618,522
Depreciation	$15,227,319
Threshold Value % - 2018	203%
Threshold Capital Expenditure $ - 2018	**$30,955,867**

Eligible Capital Amount

Table 66 below compares the 2018 capital forecast for the Brampton RZ to the Threshold Capital Expenditure to calculate the maximum eligible incremental capital of $7,113,613 for the Brampton RZ.

Table 66 – Maximum Eligible Incremental Capital – Brampton RZ

Eligible Incremental Capital	Capital Expenditures $
2018 Capital Forecast	$38,069,480
Less: Materiality Threshold	$30,955,867
Maximum Eligible Incremental Capital	**$7,113,613**

Alectra Utilities forecasted true up payment of $6,800,377 for the Brampton RZ is below the Board's maximum eligible incremental capital calculated at $7,113,613. Alectra Utilities proposes to recover $6,800,377 related to the Pleasant TS true-up.

Need

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.

The 2016 ROE for the Brampton RZ was calculated to be 7.30%, 200 basis points below its approved 2016 ROE of 9.30%. Therefore, Alectra Utilities satisfies the Means Test within the Brampton RZ. Brampton's ROE calculation for 2016, included in RRR 2.1.5.6, is filed as Attachment 19. Achieved ROE for each of the four predecessor utilities forming Alectra Utilities was within 300 basis points of deemed ROE for 2016.

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 Brampton RZ. 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 2018.

Brampton's approved 2015 distribution revenue requirement (EB-2014-0083) is $68,017,986. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement, is $340,090. The CCRA payment for Pleasant TS exceeds the materiality threshold.

Further information with respect to the driver for the CCRA payment is provided in the business case in Attachment 21.

<u>Prudence</u>

The eligible capital project for which the Brampton RZ is requesting approval is non-discretionary and is above the basis on which rates were set. The CCRA true up payment is a contractual obligation related to the CCRA between Alectra Utilities and HONI.

A description of the project's need and prudence can be found in the business case summary, set out immediately below. The project-related business case can be found at Attachment 21.

Project/ Budget/ In Service Date ("ISD")	Project Need and Description
Pleasant TS True-Up (see System Service Project Business Case SA-2018-225-001) Budget: $6.8MM (2018) Forecast ISD:	**<u>Pleasant TS DESN True-Up</u>** **<u>System Access: $6,800,377</u>** <u>Project Description and Drivers</u> • This investment relates to the contractual payment terms guided by a Connection and Cost Recovery Agreement ("CCRA") between Alectra Utilities for the Brampton RZ and HONI for the construction of the Pleasant Transformer Stations ("TS") expansion. This work was requested by the former Hydro One Brampton, in order to increase available transformation capacity for anticipated load growth in the North West area of Brampton. • The CCRA utilizes initial project costs and projected incremental load (revenue) over a 25-year horizon as inputs to determine the capital contribution payment at the project in-service date. At pre-set true-up points

Project/ Budget/ In Service Date ("ISD")	**Project Need and Description**
Q4/2018	(5, 10 and possibly 15 years after in-service), the economic evaluation is updated to reflect actual loading, and the updated load forecast to settle for demand forecast excesses or shortfalls. • Additional capital contributions may be required at a true-up point if an economic shortfall is calculated (i.e., if the actual/forecast load has decreased). Conversely, a refund may be paid at the final true-up point if an economic surplus is calculated (i.e., if the actual/forecast load has increased). • Alectra Utilities experienced a lower than forecast energy demand in the Brampton RZ due to a downturn in the economy in 2008, government-driven conservation initiatives as well as natural conservation. This reduced electrical demand at the Pleasant TS in 2008 and subsequent years, resulted in a five-year anniversary true-up payment in 2015. The ten-year true-up payment is due in 2018 and Alectra estimates a shortfall of revenue to HONI versus the forecasted demand. Request for financial settlement is anticipated from HONI in 2018 for the amount of \$6.8M with the final amount and payment terms negotiated between HONI and Alectra at that time. <u>Project Options</u> • Alectra Utilities is obligated under contract terms to true-up at the pre-determined anniversary period. • Alectra Utilities examined the option of reverting to the load forecast used in the five-year true-up. However, due to the increased risk of a larger true-up at the 15-year interval should the previous load forecast fail to materialize, this alternative was not pursued. Due to the discounted cash flow process used by the Net Present Value (NPV) model, the risk (if triggered) would translate into a substantial true-up payment at the 15-year true-up interval. Alectra Utilities has chosen to settle on revised forecasts based upon the experienced actual loading levels instead of previously projected figures.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $6,800,377 is $706,794. Table 67 below summarizes the incremental revenue requirement for the Pleasant TS true up payment.

Table 67 –Incremental Revenue Requirement – Brampton RZ

Incremental Revenue Requirement	Amount
Return on Rate base – Total	$473,674
Amortization	$226,679
Incremental Grossed Up PILs	$6,440
Total	**$706,794**

The Rate of Return has been calculated using the cost of capital parameters approved by the Board in Hydro One Brampton's 2015 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 a 40 year useful life.

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*, September 18, 2014, EB-2014-0219, page 23, as reproduced below.

> *"The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.13 The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy." (p.23)*

Similarly, PILs have been calculated using a full year of Capital Cost Allowance ("CCA") over the remaining life of the CCRA, based on Class 14.

The detailed calculation of incremental revenue requirement is provided in the Board's Capital Module Applicable to ACM and ICM ("Capital Module") filed as Attachment 18. Alectra Utilities has used the OEB 2017 Capital Module Applicable to ACM and ICM version 3.01, the most recent OEB model available at the time of filing.

Rate Riders

Alectra Utilities is seeking Board approval for the ICM rate riders, for the Brampton RZ, identified in Table 68 to recover the revenue requirement of $706,794 identified in Table 67 above. 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 18. 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 68 - Incremental Capital Funding Rate Riders – Brampton RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.23	$0.0000	kWh
General Service under 50 kW	$0.24	$0.0002	kWh
General Service 50 to 699 kW	$1.21	$0.0273	kW
General Service 700 to 4,999 kW	$10.89	$0.0317	kW
Large Use	$45.33	$0.0240	kW
Unmetered	$0.01	$0.0002	kWh
Street Lighting	$0.02	$0.1112	kW
Embedded Distributor	$40.07	$0.0000	kWh
Distributed Generation	$1.00	$0.0000	kWh

Bill Impacts - ICM Rate Riders

Table 69 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 under 0.2% for Embedded Distributor to 0.68% for Distributed Generation.

1 **Table 69 – ICM Bill Impacts (Total Bill) – Brampton RZ**

Rate Class	Unit	kWh	kW	ICM Rate Rider incl. HST	% Increase vs. Total Bill
Residential	kWh	750		$ 0.24	0.23%
General Service under 50 kW	kWh	2,000		$ 0.67	0.24%
General Service 50 to 699 kW	kW	182,500	500	$ 16.79	0.06%
General Service 700 to 4,999 kW	kW	627,216	1,432	$ 63.60	0.06%
Large Use	kW	10,220,000	20,000	$ 593.62	0.04%
Unmetered	kWh	21,296		$ 4.82	0.12%
Street Lighting	kW	2,787,508	7,922	$ 995.47	0.17%
Embedded Distributor	kWh	1,417,701	4,000	$ 45.28	0.02%
Distributed Generation	kWh	156		$ 1.13	0.80%

Summary of Bill Impacts

A summary of bill impacts for the typical customer by rate class is presented in Tables 70 to 72 below. Attachment 16 provides a detailed summary of the bill impacts for each customer class for 2018.

Table 70– Distribution Bill Impacts by Rate Class – Brampton RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ 0.23	0.98%
GS<50	kWh	2,000	$ (2.39)	(3.84)%
GS 50-699 kW	kW	500	$ (88.81)	(5.32)%
GS 700-4,999 kW	kW	1,432	$ (152.06)	(2.48)%
Large User	kW	20,000	$ (4,760.11)	(7.84)%
Street Lighting	kW	4,000	$ 1,842.87	1.31%

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

Table 71 – 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	2018 vs. 2017	
			$	%
Residential	kWh	750	$ 2.09	8.57%
GS<50	kWh	2,000	$ 2.55	4.13%
GS 50-699 kW	kW	500	$ (706.16)	(36.37)%
GS 700-4,999 kW	kW	1,432	$ (2,350.51)	(32.79)%
Large User	kW	20,000	$ 24,677.89	121.72%
Street Lighting	kW	4,000	$ (7,891.30)	(5.44)%

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

Table 72 – Total Bill Impacts by Rate Class (before HST) – Brampton RZ

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ 2.17	2.18%
GS<50	kWh	2,000	$ 2.76	1.01%
GS 50-699 kW	kW	500	$ (681.31)	(2.60)%
GS 700-4,999 kW	kW	1,432	$ (2,271.61)	(2.52)%
Large User	kW	20,000	$ 25,931.89	1.93%
Street Lighting	kW	4,000	$ (7,563.33)	(1.48)%

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

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, 2018. This application impacts customers in the Cities of 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 2018 IRM Rate Generator Model ("2018 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 – 2016 Edition for 2017 Rate Applications* (the "Filing Requirements"), dated July 14, 2016, 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 14, 2016.

Alectra Utilities also applies for incremental capital funding for the Enersource RZ in accordance with the OEB's: *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications* issued July 14, 2016 ("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. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;

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, 2016, 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, 2018;

vi. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers;

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

viii. Incremental capital rate riders effective January 1, 2018 until the next rebasing application;

ix. Approval for an accounting order for a new deferral account to record incremental capital expenditures for the GO Rail Network Electrification Project; and

x. Current (i.e., 2017) rates provided in Attachment 23 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

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 2018 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 4, 2016. The August 2016 report placed PowerStream in Group III for the purpose of calculating stretch factors for 2017.

Inflation Factor

The Industry Specific Inflation Factor for 2018 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor for the PowerStream RZ published for 2017 IRM filers; i.e., 1.9%, as a proxy for 2018.

PowerStream RZ will update the IRM Model with the 2018 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 26 is 1.60%, is identified in Table 73 below.

Table 73 – Calculation of Price Cap Index – PowerStream RZ

Factor	%
Inflation Factor	1.9%
Less: Productivity Factor	0.0%
Less: Stretch Factor	-0.3%
Price Cap Index	**1.6%**

The Price Cap Index of 1.6% has been applied to the 2017 Service Charge and Distribution Volumetric Rate by rate class to determine Alectra Utilities 2018 Service Charges and Distribution Volumetric Rates for the PowerStream RZ. The related Proposed Tariff of Rates and Charges for the PowerStream RZ is filed as Attachment 24.

The Ontario government has released the OFHP. The OFHP: i) extended the payback period for items within the Global Adjustment ("GA"), and ii) transferred the funding of certain support programs, such as the Ontario Energy Support Program ("OESP") from the electricity rate base to the tax base. A portion of the bill reduction announced in the OFHP, achieved through a reduction in Regulated Price Plan ("RPP") prices, in addition to the removal of the OESP charge of $0.0011/kWh, took effect on May 1, simultaneous with the RPP changes. The final portion of the bill reduction, achieved through a further reduction in RPP prices, in addition to a reduction to the Rural and Remote Rate Protection ("RRRP") charge from $0.0021/kWh to $0.0003/kWh, took effect on July 1. Accordingly, Alectra Utilities has incorporated the removal of the OESP and reduction to the RRRP charge in the Alectra Utilities Proposed Tariff of Rates and Charges for the PowerStream RZ.

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."*

Alectra Utilities incorporated the first year transition adjustment in its proposed rates for 2017, for the PowerStream RZ, 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 has incorporated the second year transition adjustment for its proposed rates for 2018 for the PowerStream RZ. The calculation of the proposed residential fixed and variable rates is identified in Tab 17. Rev2Cost-GDPIPI of the IRM Model filed as Attachment 26.

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 $3.27 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 10^{th} consumption percentile. The following is a description of the method that Alectra Utilities used to derive the 10^{th} 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 $1/10^{th}$ of the total number of customers ranked for the PowerStream RZ.
3. Alectra Utilities calculated the 10^{th} 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 10^{th} consumption percentile to be 309 kWh for the PowerStream RZ.

Alectra Utilities has provided the bill impact for a Residential customer who consumes 309 kWh monthly for the PowerStream RZ in Table 74 below. The monthly service charge increased by $3.27 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 2.45%.

Table 74 – 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	$ 18.51	1	$ 18.51	$ 21.78	1	$ 21.78	$ 3.27	17.68%
Distribution Volumetric Rate	$ 0.0130	308.871	$ 4.02	$ 0.0088	308.871	$ 2.73	$ (1.29)	-32.01%
Fixed Rate Riders	$ 0.04	1	$ 0.04	$ 0.43	1	$ 0.43	$ 0.39	975.00%
Volumetric Rate Riders	$ -	308.871	$ -	$ -	308.871	$ -	$ -	
Sub-Total A (excluding pass through)			$ 22.57			$ 24.94	**$ 2.38**	**10.54%**
Line Losses on Cost of Power	$ 0.0822	11	$ 0.94	$ 0.0822	11	$ 0.94	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	309	$ -	-$ 0.00260	309	$ (0.80)	$ (0.80)	
Low Voltage Service Charge	$ 0.0005	309	$ 0.15	$ 0.0005	309	$ 0.15	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24.45**			**$ 26.02**	**$ 1.57**	**6.44%**
RTSR - Network	$ 0.0082	320	$ 2.63	$ 0.0076	320	$ 2.43	$ (0.19)	-7.32%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	320	$ 1.22	$ 0.0037	320	$ 1.18	$ (0.03)	-2.63%
Sub-Total C - Delivery (including Sub-Total B)			**$ 28.29**			**$ 29.64**	**$ 1.35**	**4.77%**
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	$ 0.0950	53	$ 4.99	$ 0.0950	53	$ 4.99	$ -	0.00%
TOU - On Peak	$ 0.1320	56	$ 7.34	$ 0.1320	56	$ 7.34	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 55.17**			**$ 56.52**	**$ 1.35**	**2.45%**
HST	13%		$ 7.17	13%		$ 7.35	$ 0.18	2.45%
8% Provincial Rebate	-8%		$ (4.41)	-8%		$ (4.52)	$ (0.11)	2.45%
Total Bill on TOU			**$ 57.92**			**$ 59.34**	**$ 1.42**	**2.45%**

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 14, 2016, the OEB issued its Decision and Order in respect of the 2016 Uniform Transmission Rates ("UTRs") (EB-2015-0311). At the time of this filing, 2017 UTRs were not available. 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 page10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 75 below.

Table 75 – Current Board-Approved UTRs and STRs – PowerStream RZ

UTRs	$
Network Service Rate	$3.66
Line Connection Service Rate	$0.87
Transformation Connection Service Rate	$2.02
STRs	**$**
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 26 to incorporate i) the most recent UTRs and STRs approved by the Board; and ii) an update to demand in the PowerStream RZ from 2015 to 2016 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, 2016, in the amount of ($26,090,060), have been adjusted for the following items to determine the amount for disposition of ($25,562,406) as identified in Table 76 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 must be 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 $811,309 has been made to Account 1588 to reflect RPP settlement true-up claims for 2016 that were settled in 2017. This amount has been entered into the IRM model, Tab "3. Continuity Schedule" Column "Principal Adjustment during 2016". See Table 76 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 2017 projected carrying charges).

Table 76 – Group 1 Account Balances for Disposition – PowerStream RZ

Description	Amount
Group 1 Account Balances as of December 31, 2016	**($26,090,060)**
RPP Settlement True-up Claims Adjustment	**$811,309**
Add Projected Carrying Charges	($274,732)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($25,553,483)**

Alectra Utilities has computed the disposition threshold for the PowerStream RZ, based on the adjusted Group 1 balances to be ($0.0030)/kWh, as identified in Table 77, below. Alectra Utilities requests disposition of its Group 1 account balances for the PowerStream RZ in this Application.

Table 77 - Calculation of Disposition Threshold – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	$4,516,968
Smart Meter Entity Charge	1551	($254,992)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	$1,977,104
RSVA - Wholesale Market Service Charge excluding CBR	1580	($26,192,085)
RSVA - Retail Transmission Network Charge	1584	($6,549,552)
RSVA - Retail Transmission Connection Charge	1586	$2,650,329
RSVA – Power	1588	$1,880,069
RSVA - Global Adjustment	1589	($3,979,255)
Disposition and Recovery/Refund of Regulatory Balances	1595	($138,646)
Group 1 Account Balances as of December 31, 2016		**($26,090,060)**
RPP Settlement True-up Claims Adjustment		$811,309
Add 2017 Projected Carrying Charges		($274,732)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($25,553,483)**
2016 kWhs		8,548,768,932
Threshold Test $/kWh		**($0.0030)**

Alectra Utilities has completed Tab 3. Continuity Schedule of the IRM Model for the PowerStream RZ; it is filed as Attachment 26. Alectra Utilities has reconciled the Group 1 balances filed in the 2016 RRR for the PowerStream RZ, section 2.1.7 as identified in Table 78 below. Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2016 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 1.1% was relied upon to calculate forecasted interest for 2017. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 78 – Deferral and Variance Account Reconciliation – PowerStream RZ

Account Description	Account	Principal Amounts as of Dec 31, 2016	Carrying Charges to Dec 31, 2016	Projected Carrying Charges to Dec 31, 2017	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims Adjustment	Projected Carrying Charges to Dec 31, 2017	Total Disposition
Group 1 Accounts:								
Low Voltage	1550	4,477,534	39,432	49,253	4,566,219			4,566,219
Smart Meter Entity Charge	1551	(252,810)	(2,181)	(2,781)	(257,772)			(257,772)
RSVA - Wholesale Market Service Charge - excluding CBR	1580	(25,885,605)	(306,480)	(284,742)	(26,476,827)			(26,476,827)
RSVA - Wholesale Market Service Charge - CBR Class B	1580	1,947,271	29,833	21,420	1,998,524			1,998,524
RSVA - Retail Transmission Network Charge	1584	(6,495,670)	(53,882)	(71,452)	(6,621,004)			(6,621,004)
RSVA - Retail Transmission Connection Charge	1586	2,623,509	26,819	28,859	2,679,187			2,679,187
RSVA - Power	1588	1,859,282	20,788	20,452	1,900,522	811,309	8,924	2,720,755
Sub-total not including RSVA Power Global Adjustment		(21,726,489)	(245,671)	(238,992)	(22,211,152)	811,309	8,924	(21,390,918)
RSVA - Power Global Adjustment	1589	(4,080,477)	101,223	(44,885)	(4,024,139)			(4,024,139)
Total including RSVA Power Global Adjustment		(25,806,966)	(144,448)	(283,877)	(26,235,291)	811,309	8,924	(25,415,057)
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	2	(21,764)		(21,762)			(21,762)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	7,318	153	80	7,551			7,551
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	336	43	4	383			383
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	12,466	153,273	137	165,876			165,876
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595		(290,474)		(290,474)			(290,474)
Total 1595		20,122	(158,768)	221	(138,426)	-	-	(138,426)
Total Group 1		**(25,786,845)**	**(303,216)**	**(283,656)**	**(26,373,716)**	**811,309**	**8,924**	**(25,553,483)**
Total Amount for Disposition		**(25,786,845)**	**(303,216)**	**(283,656)**	**(26,373,716)**	**811,309**	**8,924**	**(25,553,483)**

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"*.

<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. PowerStream 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 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 ($4,024,140) 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 79 below after the discussion on the movement of customers between Class A and Class B.

Alectra Utilities proposes to start 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 part of its approved 2016 rates, Alectra Utilities has GA rate riders for the PowerStream RZ, that expire September 30, 2018, that apply to all Class B non-RPP customers (“2016 GA rate riders”). Alectra Utilities proposes to update the 2016 GA rate riders with new 2016 GA rate riders for the period January 1, 2018 to September 30, 2018.

The new 2016 GA rate riders are designed to recover the projected balance remaining at December 31, 2017 of $3,906,837, plus the over recovery from the Class B interval customers from the 2016 GA rate riders of $3,134,585, for a total of $7,041,422 to be recovered from the Class B non-RPP non-interval customers. Alectra Utilities proposes a rate rider to refund the amount over recovered of $3,134,585 to the Class B interval customers. The updated 2016 rate riders are calculated on Tab “6C. 2016 GA Rate Rider Update” of the IRM model. The resulting rate riders are summarized in Table 79 below.

Table 79: Updated 2016 GA Rate Riders – PowerStream RZ

Rate Class	Units	Approved Rate Rider Oct 1/16 to Sep 30/18	Proposed Rate Rider Jan 1/18 to Sep 30/18
RESIDENTIAL SERVICE	kWh	$0.0012	$0.0040
GENERAL SERVICE LESS THAN 50 kW	kWh	$0.0012	$0.0040
GENERAL SERVICE 500 to 4,999 kW - INTERVALS	kW	$0.4319	($0.7198)
GENERAL SERVICE 500 to 4,999 kW - NON-INTERVALS	kW	$0.4319	$1.4878
UNMETERED SCATTERED LOAD	kWh	$0.0012	$0.0040
SENTINEL LIGHTING	kW	$0.4458	$1.5308
STREET LIGHTING	kW	$0.4124	$1.4128

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 two PowerStream RZ customers who qualified as Class A customers effective July 1, 2016 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, 2016; and paid CBR as Class A customers from July 1, 2016 to December 31, 2016. These customers should be allocated only the portion of the CBR account balances which accrued prior to their classification as Class A customers (i.e., from January 1, 2015 to June 30, 2016).

There were nine PowerStream RZ customers who qualified as Class A customers effective July 1, 2015 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, 2015; and paid CBR as Class A customers from July 1, 2016 to December 31, 2016. These customers should be allocated only the portion of the CBR account balances which accrued prior to their classification as Class A customers (i.e. from January 1, 2015 to June 30, 2015).

There was one PowerStream RZ customer who opted out of Class A effective July 1, 2016. This customer paid CBR as a Class A customer up to and including June 30, 2016; and paid CBR as a Class B customer from July 1, 2016 to December 31, 2016. This customer should be allocated only the portion of the CBR account balance which accrued after their reclassification to Class B customer (i.e. from July 1, 2016 to December 31, 2016).

The CBR amounts for customers who were Class A for part of 2015 and 2016 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 rate riders. Table 80 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 ($4,024,140) 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 $1,998,524, of which $1,993,495 will be disposed of via rate rider, and $5,029 will be disposed of via specific bill adjustments. Tabs “7A. CBR Allocation_Class A” and “7A. CBR Allocation_new Class B” in the IRM Model identify the detailed calculation of the bill adjustments of $5,029 for CBR.

Alectra Utilities requests disposition of its CBR balance of $5,029 related to its new Class A customers (effective July 1, 2015 and July 1, 2016) and new Class B customers (effective July 1, 2016) through the bill adjustments identified in the IRM Model for the PowerStream RZ.

Table 80 – Disposition of GA and CBR Balances – PowerStream RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($4,024,139)
Global Adjustment - New Class A Customers July 1/2016	$0
Global Adjustment - New Class B Customers July 1/2016	$0
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**($4,024,139)**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	$1,993,495
Capacity Based Recovery - New Class A Customers July 1/2016	$4,229
Capacity Based Recovery - New Class B Customers July 1/2016	$800
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**$1,998,524**

Alectra Utilities anticipates that there will be a significant number of new Class A customers as of July 1, 2017 for the PowerStream RZ, as a result of the expansion of the ICI program. Alectra Utilities proposes to charge these customers and all customers who were Class B customers at December 31, 2016 the Class B CBR rate rider for the PowerStream RZ, with the exception of the one customer who became a Class B customer from Class A in 2016.

A summary of the rate riders applicable to each group of customers is identified in Table 81 below.

Table 80 – Rate Riders by Customer Group

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider[3]	CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2015 - Dec 31, 2016) Customers	x	x			
Class B non-RPP (Jan 1, 2015/16 - Jun 30, 2015/16)/Class A (Jul 1, 2015/16 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class B non-RPP non-interval metered (Jan 1, 2015 - Dec 31, 2016) Customers	x	x	x	x	
Class B non-RPP interval metered (Jan 1, 2015 - Dec 31, 2016) 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)
3. Class B interval customers to be charged only an a rate rider to refund amounts collected under 2016 GA appproved rate riders.

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges and the remaining balance in Account 1595 related to PowerStream's 2014 IRM Application (EB-2014-0166). Other customers have rate rider 1 and 2 combined into a single rate rider.

Class A customers (who were Class A from January 1, 2015 to December 31, 2016) 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 8, who were Class A customers for only part of 2015 or 2016, 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, 2015 to December 31, 2016 are charged DVA Rate Riders 1 and 2; the GA rate rider; the revised 2016 GA Rate Rider; and the CBR B Rate Rider.

Class B non-RPP interval metered customers who were Class B from January 1, 2015 to December 31, 2016 are charged DVA Rate Riders 1 and 2; the updated 2016 GA Rate Rider; and the CBR B Rate Rider. This group includes customers who become Class A customers in 2017 or 2018.

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 81, below. The amount to be disposed of by rate rider is ($26,300,803) and the amount to be disposed of via customer specific bill adjustments is $4,976 CBR A)

Table 81 – Group 1 Disposition by Customer Group – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	$4,566,219
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($257,772)
Retail Transmission Network Charge	1584	($6,621,004)
Retail Transmission Connection Charge	1586	$2,679,187
Disposition and Recovery/Refund of Regulatory Balances	1595	($138,426)
All Customers - DVA Rate Rider 1		**$228,204**
Power	1588	$2,720,755
Wholesale Market Service Charge excluding CBR	1580	($26,476,827)
All Customers ex WMPs - DVA Rate Rider 2		**($23,756,072)**
Wholesale Market Service Charge - CBR Class B	1580	$1,993,495
Capacity Based Recovery - New Class A Customers July 1/2016	1580	$4,229
Capacity Based Recovery - New Class B Customers July 1/2016	1580	$800
All Class A Customers ex WMPs - CBR B Bill Adjustment	**1580**	**$1,998,524**
Global Adjustment - Non-RPP Class B Customers Jan 1/2016 -Dec 31/2016	1589	($4,024,139)
Global Adjustment - New Class A Customers July 1/2016 or July 1/2015	1589	$0
Global Adjustment - New Class B Customers July 1/2016	1589	$0
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**($4,024,139)**
Total (Repayment to)/Recovery from Customers		**($25,553,483)**
Disposition via Rate Rider		($25,558,512)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2015-2016		$0
Disposition via Customer Specific Bill Adjustments - CBR for Class A customers only a portion of 2015-2016		$5,029

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2016 actual quantities reported in Alectra Utilities RRRs for PowerStream have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016.

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 26. Table 82 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 82 – Proposed Rate Riders by Class – PowerStream RZ

Customer Class	Deferral and Variance Account Rate Rider		Deferral and Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B from Jan 1/2015 - Dec 31/2016		CBR B Rate Rider Class B Consumer from Jan 1/2015 - Dec 31/2016	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
RESIDENTIAL	(0.0028)				(0.0017)		0.0002	
GENERAL SERVICE <50 KW	(0.0027)				(0.0017)		0.0002	
GENERAL SERVICE >50 KW		0.0182		(1.0567)	(0.0017)			0.0908
LARGE USE		(1.2283)			(0.0017)			0.0000
UNMETERED & SCATTERED LOADS	(0.0027)				(0.0017)		0.0002	
SENTINEL LIGHTS	(0.9968)				(0.0017)			0.0898
STREET LIGHTING	(0.9768)				(0.0017)			0.0872

Alectra Utilities requests disposition of its adjusted Group 1 balances of ($25,558,512), identified in Table 81, through the rate riders identified in Table 82 above for the PowerStream RZ. For a typical Residential customer using 750 kWh/month and paying RPP rates, the bill impact of the proposed rate riders is a decrease of ($1.95) /month or (1.8%) on the total bill.

Alectra Utilities understands that OEB staff are testing a new Global Adjustment Analysis workform for the 2018 IRM process. At the time of this filing, a final work form is not available. Alectra Utilities anticipates providing the completed workform once it is released by the OEB.

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 83 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 83– 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. Estimated Claim for the Current Month

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

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 84 below.

Table 84 – 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 2016 will have been billed by February 28, 2017). 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.

Establishment of New Deferral and Variance Accounts

Alectra Utilities requests approval for an accounting order to establish a new deferral account for the PowerStream RZ to record the financial impacts resulting from the MetroLinx Crossing Remediation Project, in accordance with the OEB's: *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 Cost of Service*, issued July 14, 2016. The OEB states that:

> *In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:*
>
> *Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.*
>
> *Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.*
>
> *Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.*

The Metrolinx Regional Express Rail ("RER") Electrification program is an infrastructure roll out plan by Metrolinx that will entail the conversion of six of the eight GO rail corridors from diesel to electric propulsion. This will help to transform the way the region moves by building a seamless, convenient and integrated transit network across the Greater Toronto and Hamilton Area ("GTHA").

As part of this project, GO Transit plans to enable 15-minute service on most corridors with electrified trains, increasing the frequency of service in the GTHA by four times the current number of GO train trips on evenings and weekends, and twice the number of trips during peak periods. The program will involve planning, design, and implementation of a traction power supply system and power distribution components including Overhead Catenary System ("OCS") along the rail corridors to be electrified.

The OCS is comprised of portal/cantilever structures that support wires on assemblies. The electric train is supplied power through a connection between the roof of the train and an overhead wire. With the addition of the cantilever structures for electrification, the existing overhead crossings will not meet the clearance and safety standards for the existing poles lines. This will require remediation by either moving the plant to underground or rebuilding the crossings overhead to provide adequate clearances. In addition, there are some grade separation projects that will be required.

Alectra Utilities has determined that all of the overhead crossings along the Barrie and Stouffville corridors are in conflict with the OCS system for the GO electrification and will need to be remediated by either rebuilding the overhead system with increased clearances by utilizing taller poles or by moving the existing lines underground. Metrolinx's Electrification Third Party Utility Team has identified a total of 69 distribution system assets in the PowerStream RZ along the Barrie and Stouffville corridors which are in conflict. A total of 48 assets were identified in the Barrie corridor; 21 were identified along the Stouffville corridor.

Alectra Utilities is assessing the impact and options for mitigation of the identified conflicts in the PowerStream RZ. Due to restrictions on height of the existing equipment and limitations due to maintenance schedule window, it was determined that the best option for mitigation of the overhead primary distribution crossings is to convert them to underground crossings.

The timelines for tender is scheduled for 2019 and actual construction is expected to start in 2020. Metrolinx has informed Alectra Utilities that several crossings in the PowerStream RZ will need to be remediated between 2017-2019. Based on the proposed schedule, Alectra Utilities anticipates 10 to 15 crossings may need to be remediated in 2018 in order to align with Metrolinx's schedule for construction. As the final design and identification of the specific number crossings to be remediated have not been finalized by Metrolinx, project costs have not been developed. Alectra Utilities continues to monitor the progress and timelines of the project schedule as they are dependent on Metrolinx.

The requested new deferral account satisfies the Board's eligibility criteria:

Causation – Alectra Utilities confirms that the forecasted underground and overhead capital expenditures required to support the Metrolinx Crossings Remediation Project are not included in the PowerStream RZ DSP; no previous recovery has been sought or approved by the Board for this expenditure.

Materiality – At the timing of filing, a final project schedule outlining the crossings to be remediated in 2018 and which are in conflict with Metrolinx's OCS system for the GO electrification has not been provided. The existing Metrolinx Crossing Agreements specify that the utility is solely responsible for the relocation costs for its distribution system assets. These costs are anticipated to be material.

Prudence – Alectra Utilities is obligated to remove or relocate certain parts of its distribution system in the vicinity of the rail lines. The Metrolinx Crossing Agreement provides that *"should it become necessary or expedient for the purposes of repair or improvement of the railway line that the Works be temporarily removed or relocated, the Applicant shall upon request of the Owner and at the sole cost of the Applicant forthwith remove or relocate the Works".*

Alectra Utilities has filed at Attachment 27 a proposed accounting order which includes a description of the mechanics of the account, examples of the general ledger entries and the proposed manner in which to dispose of the account related to this project in the PowerStream RZ.

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 85 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.

Alectra Utilities is requesting to collect renewable generation funding of $266,079 in 2018 or $22,173 per month from all provincial ratepayers for the PowerStream RZ, as identified in Table 85 below.

Table 85: Green Energy Plan Rate Protection Benefit and Charge in 2018 – 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 2014 and 2015 in the PowerStream RZ. The total amount requested for disposition is a debit of $1,377,886 including forecasted carrying charges of $45,740 through to December 31, 2017. Actual savings from CDM activities for 2014 and 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. PowerStream's most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR Application (EB-2015-0003). In that proceeding, the Board approved PowerStream's request to recover lost revenues from CDM activities in 2013.

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 $1,699,829, 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 14, 2016, and is provided in Attachment 28. 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 2011 to 2014 and 2015 are filed as Attachments 29 and 30 respectively.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2016. Alectra Utilities proposes to dispose of its 2016 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 2016 balances as mentioned, previously.

Alectra Utilities is seeking recovery of lost revenues, for the PowerStream RZ, for the period January 1, 2014 to December 31, 2015 resulting from the following:

(i) 2011 to 2013 CDM persistence savings in 2014 and 2015; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2014 and 2015, including persistence through 2015.

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 86 identified below.

Table 86 – Distribution Volumetric Rates – PowerStream RZ

Year	Residential	GS<50 kW	GS>50 kW	Large Use	Unmetered	Sentinel Lighting	Street Lighting
	kWh	kWh	kW	kW	kWh	kW	kW
2011	$0.0134	$0.0115	$3.4709	$1.0387	$0.0086	$9.3042	$4.8163
2012	$0.0135	$0.0116	$3.4934	$1.0454	$0.0087	$9.3644	$4.8475
2013	$0.0135	$0.0116	$3.5036	$1.0484	$0.0087	$9.3917	$4.8616
2014	$0.0136	$0.0135	$3.2397	$1.3784	$0.0155	$7.8050	$6.4785
2015	$0.0138	$0.0137	$3.2851	$1.3977	$0.0157	$7.9143	$6.5692

Alectra Utilities' LRAMVA threshold in the PowerStream RZ, 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 2014 and 2015. PowerStream's LRAMVA threshold is provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 87 identified below.

Table 87 – LRAMVA Thresholds – PowerStream RZ

Year	LRAMVA Threshold	Residential	GS<50 kW	GS>50 kW	Large Use	Unmetered	Sentinel Lighting	Street Lighting
		kWh	kWh	kW	kW	kWh	kW	kW
2011		0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0
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

Alectra Utilities has calculated carrying charges for the PowerStream RZ on the LRAM amounts from January 1, 2014 to December 31, 2015 in the LRAMVA work form using the OEB's annual prescribed interest rates of 1.47% to March 31, 2015 and 1.1% thereafter as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $1,699,829, representing a principal balance of $1,645,589 and carrying charges of $54,240.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class for the PowerStream RZ, in Tables 88 and 89 below, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 88– LRAMVA Totals by Rate Class – PowerStream RZ

Customer Class	Billing Unit	Principle ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$9,610	($585)	$9,025
GS<50 kW	kWh	$895,420	$30,492	$925,912
GS>50 kW	kW	$795,161	$26,181	$821,342
Large Use	kW	($10,360)	($351)	($10,711)
Unmetered	kWh	($6,509)	($220)	($6,729)
Sentinel Lighting	kW	($316)	($11)	($326)
Street Lighting	kW	($37,418)	($1,266)	($38,685)
Total		**$1,645,589**	**$54,240**	**$1,699,829**

Table 89– LRAMVA by Year and Rate Class – PowerStream RZ

Description	Residential	GS<50 kW	GS>50 kW	Large Use	Unmetered	Sentinel Lighting	Street Lighting	Total
	kWh	kWh	kW	kW	kWh	kW	kW	
2014 Actuals	$538,810	$687,756	$974,059	$0	$0	$0	$0	$2,200,625
2014 Forecast	($601,228)	($229,292)	($633,139)	($5,144)	($3,234)	($157)	($18,579)	($1,490,772)
2014 LRAM Balance	**($62,418)**	**$458,465**	**$340,920**	**($5,144)**	**($3,234)**	**($157)**	**($18,579)**	**$709,853**
2015 Actuals	$682,098	$669,644	$1,096,253	$0	$0	$0	$0	$2,447,995
2015 Forecast	($610,069)	($232,689)	($642,011)	($5,216)	($3,275)	($159)	($18,839)	($1,512,259)
2015 LRAM Balance	**$72,029**	**$436,955**	**$454,242**	**($5,216)**	**($3,275)**	**($159)**	**($18,839)**	**$935,736**
Carrying Charges	**($585)**	**$30,492**	**$26,181**	**($351)**	**($220)**	**($11)**	**($1,266)**	**$54,240**
Total LRAMVA Balance	**$9,025**	**$925,912**	**$821,342**	**($10,711)**	**($6,729)**	**($326)**	**($38,685)**	**$1,699,829**

The proposed rate riders that result from the disposition of Account 1568, LRAM Variance Account, is identified in Table 90 below and included in Tab “8. Calculation of Def-Var RR” in the IRM Model.

Table 90 – LRAMVA Rate Riders – PowerStream RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.00	$0.0000	kWh
General Service under 50 kW	$0.00	$0.0009	kWh
General Service 50 to 4999 kW	$0.00	$0.0677	kW
Large Use	$0.00	($0.0714)	kW
Unmetered	$0.00	$0.0005	kWh
Sentinel Lights	$0.00	($0.3805)	kW
Street Lighting	$0.00	($2.6090)	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 for the PowerStream RZ, as the corporate tax rates for 2016 and 2017 are 26.50% and are not expected to change in 2018. As result there is no shared tax savings in this rate 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). The PowerStream DSP 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 is seeking OEB approval for incremental capital funding for the PowerStream RZ for 2018, through distribution rate riders as identified in Attachment 31. 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 renewal, system access and system service. As previously stated, the PowerStream RZ is on Price Cap IR for the purpose of setting 2018 electricity distribution rates and, therefore, the ICM is available to the PowerStream RZ.

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.

PowerStream's asset management planning process, 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.

PowerStream has a robust capital planning process 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 governance 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, and for renewal of aging distribution infrastructure; a theme articulated in its last Cost of Service 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 8,000 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.

System renewal investments in the PowerStream RZ are largely driven by aging infrastructure and climate change pressures. A significant portion of the PowerStream RZ's asset infrastructure was installed during the local economic expansion years of the 1950s, 1960s, and 1970s. This infrastructure is now largely due for renewal. The PowerStream RZ has been able to extend the life of this equipment through careful management and prudent investments focused on the long term stewardship of these assets. However, a portion of these assets is at, or nearing, end-of-life, and must be replaced along a carefully managed timeframe in a manner that balances distribution system risks, customer rate impacts and customer preferences. Further, severe weather and storms have increased the cost of emergency maintenance, reactive replacement, and customer outages. The PowerStream DSP includes capital investments required to harden or strengthen the overhead distribution system to withstand the frequency and severity of storms (wind, rain, ice) that have been experienced over the last few years and, according to meteorologists, are expected to become more common in the future.

Alectra Utilities provides a summary of its proposed 2018 capital investments by investment category below, with a comparison to historical spending and the capital spending approved for 2018 in the PowerStream DSP.

Tables 91 and 92 below identify historical and forecasted capital spending by category, for the PowerStream RZ, for the period from 2013 to 2020. Amounts shown are net of contributed capital. The 2018 capital expenditures filed in the PowerStream DSP were $125.5MM; Alectra Utilities' forecasted capital expenditures for 2018 prior to customer consultation were $109.8MM; a decrease of $15.7MM as compared to the PowerStream DSP.

The OEB directed PowerStream to reduce its 2017 capital expenditures for system renewal and general plant in its Decision and Order in PowerStream's 2017 Cost of Service Application (EB-2015-0003)[11]. The OEB approved the revised capital budget for 2017 using an "envelope" approach permitting "*PowerStream to determine the appropriate way to allocate the capital budget within the limits of the total capital budget for the year*". In order to determine its capital forecast for 2018 (prior to customer engagement), Alectra Utilities reduced its 2018 proposed capital budget for the PowerStream RZ of $125.5MM by the same reduction that the OEB mandated for 2017. The reductions were primarily for system renewal programs which continued over the 5-year DSP term, for which the PowerStream RZ has paced investments and deferred replacements to future years.

Table 91: Capital Expenditures by Category from 2013 to 2020 ($000s) – PowerStream RZ

Category	Actual 2013	Actual 2014	Actual 2015	Actual 2016	COS 2017	Forecast 2017	DSP 2018	Forecast 2018	Forecast 2019	Forecast 2020
System Access	$17,030	$26,229	$25,620	$22,790	$32,024	$32,024	$29,561	$32,213	$30,531	$30,667
System Renewal	$22,254	$39,186	$46,997	$42,004	$41,848	$41,848	$51,650	$45,292	$43,320	$49,346
System Service	$34,780	$17,946	$23,542	$27,529	$30,986	$30,986	$30,426	$20,522	$24,448	$14,659
General Plant	$19,593	$26,148	$22,092	$8,839	$10,927	$17,500	$13,863	$11,747	$5,933	$15,564
Total	**$93,657**	**$109,509**	**$118,251**	**$101,162**	**$115,784**	**$122,357**	**$125,500**	**$109,773**	**$104,231**	**$110,236**

Alectra Utilities provides an explanation of capital expenditures for the PowerStream RZ from 2013 to 2020 by system category below. Alectra Utilities has filed at Attachment 35, details by project for the proposed 2018 capital spending plan.

[11] Decision and Order (EB-2015-0003) page 15

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 92 below.

Table 92 – System Access Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2013	Actual 2014	Actual 2015	Actual 2016	COS 2017	Forecast 2017	DSP 2018	Forecast 2018	Forecast 2019	Forecast 2020
New Connections and Subdivisions	$9,310	$8,759	$14,291	$13,761	$15,644	$15,644	$16,521	$16,162	$16,719	$17,274
Other Customer Initiated Work	$264	$1,085	$355	($270)	$404	$404	$1,080	$425	$446	$468
RGEN New Connections	$83	$30	$105	$166	($0)	($0)	$0	$0	$0	$0
Road Authority	$2,424	$13,950	$7,422	$7,301	$13,070	$13,070	$8,357	$12,796	$8,926	$6,165
System Access Other Misc	$0	$0	$1	$41	$0	$0	$59	$0	$0	$0
Metering	$4,950	$2,406	$3,446	$1,791	$2,905	$2,905	$3,544	$2,831	$4,440	$6,760
System Access	**$17,030**	**$26,229**	**$25,620**	**$22,790**	**$32,024**	**$32,024**	**$29,561**	**$32,213**	**$30,531**	**$30,667**

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.

Metrolinx Crossing Remediation Project

The Metrolinx Regional Express Rail (“RER”) Electrification program is an infrastructure roll out plan by Metrolinx that will entail the conversion of six out of eight GO rail corridors from diesel to electric propulsion. This will help to transform the way the region moves by building a seamless, convenience and integrated transit network across the Greater Toronto and Hamilton Area (“GTHA”).

Alectra Utilities has determined that all of the overhead crossings along the Barrie and Stouffville corridors are in conflict with the OCS system for the GO electrification and will need to be remediated by either rebuilding the overhead system with increased clearances by utilizing taller poles or by moving the existing lines underground

Metrolinx has indicated to Alectra Utilities that remediation at some crossings may need to commence in 2018. However, at the time of filing, Alectra Utilities had not received a firm schedule or detailed designs from Metrolinx and therefore did not include expenditures related to the GO Electrification in its capital funding request for 2018 or in its forecast for 2018-2020. Alectra Utilities requests that these expenditures be recorded in a variance account for future disposition, as discussed on page x of the application.

System Renewal

System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets.

Table 93 – System Renewal Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2013	Actual 2014	Actual 2015	Actual 2016	COS 2017	Forecast 2017	DSP 2018	Forecast 2018	Forecast 2019	Forecast 2020
UG Lines - Planned Asset Replacement	$7,235	$23,829	$22,467	$17,893	$16,714	$16,714	$23,781	$17,311	$17,561	$17,814
Overhead Lines - Planned Asset Replacement	$5,042	$5,354	$7,489	$7,733	$7,456	$7,456	$8,040	$8,223	$6,583	$7,074
Distribution Lines - Emergency/Reactive	$8,219	$8,700	$11,233	$8,416	$9,291	$9,291	$8,888	$9,524	$9,748	$9,933
Stations Replacement Project	$1,758	$1,244	$0	$0	$0	$0	$0	$0	$0	$0
Stations/P&C - Planned and Emergency	$0	$0	$2,044	$3,655	$2,587	$2,587	$3,441	$4,435	$3,628	$8,726
Storm Hardening & Rear Lot Conversion	$0	$60	$3,276	$4,308	$5,800	$5,800	$7,500	$5,800	$5,800	$5,800
System Renewal Other Misc	$0	$0	$489	$0	$0	$0	$0	$0	$0	$0
System Renewal	**$22,254**	**$39,186**	**$46,997**	**$42,004**	**$41,848**	**$41,848**	**$51,650**	**$45,292**	**$43,320**	**$49,346**

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.

Capital expenditures have decreased in 2018 as compared to the PowerStream DSP to incorporate the deferral of replacements to future years and pace investments over the 2018-2020 period to balance distribution system risks and customer rate impacts.

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 94 – System Service Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2013	Actual 2014	Actual 2015	Actual 2016	COS 2017	Forecast 2017	DSP 2018	Forecast 2018	Forecast 2019	Forecast 2020
Additional Capacity - Lines	$8,071	$3,832	$7,159	$10,794	$16,690	$16,690	$11,698	$10,329	$13,321	$2,001
Additional Capacity - Stations	$1,640	$5,752	$9,180	$13,234	$8,850	$8,850	$12,261	$4,748	$4,411	$4,778
Reliability including Distribution Automation	$4,585	$3,617	$4,250	$3,216	$4,070	$4,070	$5,173	$3,970	$5,223	$5,820
Smart Grid/RGEN - System Related	$0	$0	$0	$0	$1,070	$1,070	$1,070	$1,070	$1,070	$1,070
Station Safety & Security	$416	$80	$116	$22	$223	$223	$225	$405	$423	$989
System Service Other Misc	$20,069	$4,667	$2,836	$262	$83	$83	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Service	**$34,780**	**$17,946**	**$23,542**	**$27,529**	**$30,986**	**$30,986**	**$30,426**	**$20,522**	**$24,448**	**$14,659**

As mentioned above, the Alectra Utilities continues to experience growth in York Region and parts of Simcoe County due to favourable economic conditions and a strong housing market. The increase in capital expenditures from 2014 to 2017 is due to the following investments, required to support increased capacity requirements:

- new transformer and municipal stations;
- the integration of feeders from the stations to the distribution system;
- new pole lines to accommodate growth areas; and
- smart grid developments

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 95 – General Plant Capital Expenditures ($000s) – PowerStream RZ

Category	Actual 2013	Actual 2014	Actual 2015	Actual 2016	COS 2017	Forecast 2017	DSP 2018	Forecast 2018	Forecast 2019	Forecast 2020
Buildings and Emerging Operations	$1,178	$2,304	$4,227	$473	$965	$976	$729	$734	$784	$948
Customer Information Systems	$9,490	$15,577	$11,264	$3,137	$1,498	$7,498	$2,996	$2,970	$0	$2,675
Fleet	$1,855	$812	$1,715	$1,779	$1,510	$1,510	$2,386	$1,495	$1,489	$1,473
General Plant Other Misc	$146	($1)	$0	$0	$0	$0	$0	$0	$0	$0
Interest Capitalization	$1,105	$1,451	$922	$691	$1,040	$1,602	$1,061	$1,061	$1,613	$1,640
IT and Info/Communication Systems	$4,937	$5,068	$3,531	$2,315	$3,896	$3,896	$4,555	$3,689	$267	$6,943
Smart Grid - Other	$0	$0	$0	$0	$1,337	$1,337	$1,338	$1,338	$1,337	$1,338
Tools	$883	$937	$432	$444	$679	$679	$798	$460	$442	$547
General Plant	**$19,593**	**$26,148**	**$22,092**	**$8,839**	**$10,927**	**$17,500**	**$13,863**	**$11,747**	**$5,933**	**$15,564**

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 and synergies have been excluded from the general plant expenditures in Table 95 above. Only capital expenditures related to on-going business requirements for the PowerStream RZ are included. The increase of $6.6MM from the 2017 Cost of Service Application to the 2017 Forecast is primarily due to the advancement of the upgrade to the CIS for the PowerStream RZ.

Customer Consultation

As previously discussed, Alectra Utilities engaged Innovative to solicit feedback from customers on proposed incremental capital funding for the PowerStream RZ. The Innovative Report is provided as Attachment 51.

A multifaceted customer engagement program was designed by Innovative to collect feedback from rate classes across multiple rate zones, including the PowerStream RZ. As discussed below, the program included a voluntary online feedback portal allowing customers an opportunity to provide feedback. The number of responses to the online portal was unprecedented. Innovative also undertook telephone surveys among Residential and General Service customers to ensure feedback from representative customer samples.

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, that 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 conducting customer engagement, Alectra Utilities determined the maximum eligible capital it could apply for in the PowerStream RZ, based on its most recent 2018 capital forecast of $109,773,500, as identified in Table 91 above, and its materiality threshold of $83,881,705. The computation of the materiality threshold is discussed in further detail below. The difference between the 2018 capital forecast, before incorporating customer preferences, and the materiality threshold was $25,891,795 as identified in Table 96 below.

Table 96 – Eligible Incremental Capital for Customer Consultation – PowerStream RZ

Eligible Incremental Capital	Capital Expenditures $
2018 Capital Forecast	$109,773,500
Less: Materiality Threshold	$83,881,705
Maximum Eligible Incremental Capital	$25,891,795

Alectra Utilities identified eleven discrete and material capital projects for the PowerStream RZ for presentation to customers which totalled approximately $26.6MM. These projects are identified in Table 97 below and do not include projects related to General Plant, for which Alectra Utilities is not seeking incremental capital funding.

Table 97 - Eligible Capital Projects for Customer Consultation – PowerStream RZ

Project Description	Capital Expenditures $
Road Authority YRRT Yonge St	$11,243,530
System Access	**$11,243,530**
Station Switchgear Replacement (ACA) 8th Line MS323	$1,394,991
Rear Lot Supply Remediation - Royal Orchard - North	$1,681,034
Rear Lot Supply Remediation - Queen/Greenway	$1,457,932
Cable Replacement – (M49) - Steeles and Fairway Heights	$1,842,953
Cable Replacement – (V08) - Steeles Ave and New Westminster	$2,637,046
Planned Circuit Breaker Replacement - Richmond Hill TS#1	$1,186,729
System Renewal	**$10,200,685**
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	$1,372,976
Mill Street MS835 TX Upgrade - Tottenham	$1,298,572
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1,202,306
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	$1,276,180
System Service	**$5,150,033**
Total PowerStream Rate Zone Incremental Capital Funding	**$26,594,248**

As identified in the Innovative Report filed as Attachment 51, customers were presented with the 2018 bill impacts related to the implementation of the projects listed in Table X above. These are identified in Table 98 below. The calculation of the rate riders associated with the proposed ICM is provided in Attachment 31. Large Use customers were presented with individual bill impacts based on historical usage.

Table 98 – Bill Impacts for Incremental Capital Presented to Customers – PowerStream RZ

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	Rate Class GS<50 (2000 kWh)	GS>50
System Access	$11.2	$0.11	$0.28	$4.76
System Service	$5.2	$0.05	$0.13	$2.18
System Renewal	$10.2	$0.10	$0.26	$4.32
Total	**$26.6**	**$0.26**	**$0.67**	**$11.26**

Further, for system service and system renewal projects, customers were asked which capital investment approach they would prefer Alectra Utilities to take in 2018 for the PowerStream RZ: (i) system reliability is maintained (correlates with bill impacts identified in Table 98 above); (ii) system reliability eventually declines, calculated at 50% of the bill impacts identified in Table 98 above; and (iii) system reliability significantly declines.

A total of 17,595 customers completed the on-line survey of which 7,093 were from the PowerStream RZ: 6,962 residential customers and 131 GS<50 kW customers. A total of 918 customers from the PowerStream RZ completed the telephone survey: 516 residential customers, 201 small business (GS<50 kW) customers, and 201 mid-market (GS > 50kW) customers. The customer engagement research suggested that investments in addressing growth pressures (system service projects) are somewhat more important than replacing aging infrastructure (system renewal projects) for customers in the PowerStream RZ. General Service customers are, in general, more supportive than residential customers of investments that maintain system reliability.

Tables 99 and 100 below summarize the % of residential, GS<50 kW and GS>50 kW customers who support Alectra Utilities' request for incremental capital funding for the PowerStream RZ, by investment category.

Two scenarios are presented: (i) the % of customers who support the incremental funding request is based on the total number of respondents completing the survey; and (ii) the % of customers who support the incremental funding request is based on the total number of respondents who felt they knew enough to answer the question *"Given the varying levels of reliability under each scenario below and the projected customer rate impact of each, please indicate which approach* [maintain reliability, reliability declines, reliability significantly declines] *you want PowerStream to pursue in 2018?"*

Table 99 - % of Respondents Supporting Incremental Capital Funding for System Service Projects – PowerStream RZ

System Service - Maintain	% Respondents incl "Don't Know"		% of Respondents excl "Don't Know"	
	On-Line Survey	Telephone Survey [1]	On-Line Survey	Telephone Survey [1]
Residential	50%	41%	60%	45%
Small Business	36%	54%	46%	55%
Mid-Market	n/a	52%	n/a	54%

1. Recoded

Table 100 - % of Respondents Supporting Incremental Capital Funding for System Renewal Projects – PowerStream RZ

System Renewal - Maintain	% Respondents incl "Don't Know"		% of Respondents excl "Don't Know"	
	On-Line Survey	Telephone Survey [1]	On-Line Survey	Telephone Survey [1]
Residential	43%	38%	51%	42%
Small Business	32%	52%	43%	54%
Mid-Market	n/a	44%	n/a	44%

1. Recoded

Based on feedback from customers, as provided in the Innovative Report, PowerStream revised its 2018 capital forecast from $109,773,500 to $108,315,568; and its ICM request from $26,594,248 to $25,136,316. No revision was made to the 2018 forecast or incremental capital funding request for System Service projects. The system renewal forecast and incremental capital funding request for 2018 was reduced by $1,457,932, which represents the removal of the Rear Lot Supply Remediation project at Queen/Greenway.

While this is an important project, it benefits relatively fewer residential customers than the other renewal related ICM projects (i.e. replacement of cables, station switchgear, and circuit breakers). These projects also benefit general service customers and are necessary to avoid degradation in system reliability and service quality.

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 31.

Materiality

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:

$$\textit{Threshold Value}\,(\%) = 1 + [(\tfrac{RB}{d}) \times (g + PCI \times (1 + g))]] \times ((1 + g) \times (1 + PCI)^{n-} + 10\%$$

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 1.6% and a growth rate of 0.82%.

The PCI of 1.6% is a placeholder to be updated with the OEB's approved PCI for 2018 when it is available. It is based on inflation of 1.9% less a productivity factor of 0% and a stretch factor of 0.3% as identified in Table x 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 Table x below.

Table 101 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula approved in the ACM Report. The threshold value for 2018 is 160% which results in a threshold capital expenditure value of $83,881,705.

Table 101 – Threshold Capital Expenditure Calculation – PowerStream RZ

Description	Amount
Inflation	1.90%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	1.60%
2017 Volumes @ 2017 Rates	$201,816,357
2016 Volumes @ 2017 Rates	$200,168,360
Growth Factor	0.82%
Year	2018
# Years since rebasing	1
Price Cap Index	1.60%
Growth Factor	0.82%
Dead Band	10%
Rate Base	$1,082,805,165
Depreciation	$52,272,173
Threshold Value % - 2018	160%
Threshold Capital Expenditure $ - 2018	**$83,881,705**

Eligible Capital Amount

Table 102 below compares the 2018 capital forecast for the PowerStream RZ to the Threshold Capital Expenditure to calculate the maximum eligible incremental capital of $25,891,785 for the PowerStream RZ.

Table 102 – Maximum Eligible Incremental Capital – PowerStream RZ

Eligible Incremental Capital	Capital Expenditures $
2018 Capital Forecast	$109,773,500
Less: Materiality Threshold	$83,881,705
Maximum Eligible Incremental Capital	$25,891,795

Table 103 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 33.

Table 103– 2018 Eligible Capital Projects by Category – PowerStream RZ

Project Description	Capital Expenditures $
Road Authority YRRT Yonge St	$11,243,530
System Access	**$11,243,530**
Station Switchgear Replacement (ACA) 8th Line MS323	$1,394,991
Rear Lot Supply Remediation - Royal Orchard - North	$1,681,034
Cable Replacement – (M49) - Steeles and Fairway Heights	$1,842,953
Cable Replacement – (V08) - Steeles Ave and New Westminster	$2,637,046
Planned Circuit Breaker Replacement - Richmond Hill TS#1	$1,186,729
System Renewal	**$8,742,753**
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	$1,372,976
Mill Street MS835 TX Upgrade - Tottenham	$1,298,572
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1,202,306
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	$1,276,180
System Service	**$5,150,033**
Total PowerStream Rate Zone Incremental Capital Funding	**$25,136,316**

<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.

PowerStream's 2016 ROE was calculated to be 7.88%, 105 basis points below its approved 2016 ROE of 8.93%. Therefore, Alectra Utilities the Means Test. In the PowerStream RZ. PowerStream's ROE calculation for 2016, filed in RRR 2.1.5.6, is filed as Attachment 32. Achieved ROE for each of the four predecessor utilities forming Alectra Utilities was within 300 basis points of deemed ROE for 2016.

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. 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 2018.

PowerStream's approved 2017 distribution revenue requirement (EB-2015-0003) is $199,501,461. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $997,500. Each of the eligible projects identified in the business case summaries below exceeds the materiality threshold. Further, they are new projects for which capital funding has not previously been approved in PowerStream's last Cost of Service Application (EB-2015-0003).

Further information with respect to the driver of each project is provided in each business case in Attachment 33.

Prudence

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 33.

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 33.

Project/ Budget/ In Service Date ("ISD")	**Project Need and Description**
York Region Rapid Transit (YRRT) VIVA Bus Rapid Transit (BRT) Y2 and H2 Projects (see System Access Project Business Case 101762) Budget: $12.71MM (2017), $11.24MM (2018), $4.49MM (2019) Forecast ISD: 2017 Phase – Q4/2017 2018 Phase - Q4/2018 2019 Phase – Q4/2019	**<u>York Region Rapid Transit (YRRT) VIVA Bus Rapid Transit ("BRT") Y2 and H2 Projects</u>** **<u>System Access: $11.24MM</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 Y2 and H2 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. <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 mandatory. • Based on the design and construction timelines provided by YRRTC and its

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<td>contractors, Alectra Utilities expects to incur $12.71MM for 2017, $11.24MM for 2018, and $4.49MM for 2019. With respect to the BRT build for 2018, Alectra Utilities' cost estimate incorporates the distribution plant relocation that will be completed in 2018. While Alectra Utilities maintains close contact and coordination with YRRTC to obtain the best available information, it has no control over the design and timelines of the BRT developments. In light of this uncertainty and the risk that the scope of the BRT build for 2018 may increase, Alectra Utilities believes that any cost variances should be addressed through the ICM true-up mechanism.</td>
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<td>Station Switchgear Replacement – 8th Line MS323

(see System Renewal Project Business Case 102730)

Budget:

$0.39MM (2017),
$0.93MM (2018)

Forecast ISD: Q4/2018</td>
<td>Station Switchgear Replacement - 8th Line MS323
System Renewal: $1.32MM

<u>Project Description and Drivers</u>

• The 8th Line MS323 is one of four municipal stations operated by Alectra Utilities in the Bradford service area. It has a capacity of 10MVA and serves approximately 2,700 customers. The station's low voltage switchgear includes four circuit breakers that have been assessed through the ACA process as being in poor condition (thus at high risk of failure) and are no longer supported by the manufacturer.

• The equipment at MS323 is outdoors and vulnerable to adverse weather, which contributes to a higher likelihood of equipment failure. The station's switchgear needs to be brought to current acceptable standards, with respect to arc-resistant construction to reduce the risk of failure. Addressing this issue is expected to avoid 97,200 customer outage minutes per year, which would have otherwise affected 900 residential and commercial customers.

<u>Project Options</u>

• The proposed solution is to replace the existing switchgear at 8th Line MS323 with new 15kV metal-clad switchgear (with arc-resistant construction as per present day standards). To achieve efficiencies and cost savings, the project will include ancillary work (including renewing power cables and terminations, cable duct banks, oil containment, communications and relay panels) required to bring the station to current standards and improve reliability. If carried out separately from the project, such ancillary work will result in higher costs due to the need to undertake construction and installation again at the substation. Since the replacement switchgear would not fit in the existing enclosure at the station, a new switchgear prefabricated building will also be required. Purchasing the switchgear with a prefabricated building will help reduce outage time for project construction from approximately 12 weeks to 4 weeks.</td>
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Alternate options considered included: (i) continuing to operate the existing switchgear (which may result in outages that are about 4-hours long to allow for load transfer, and/or lengthy outages at the station due to the unavailability of spare parts required to replace or repair the obsolete breakers; and (ii) retrofitting the circuit breakers (which would neither be cost effective nor achieve the safety benefits offered by arc-resistant replacement switchgear). The proposed solution is the most cost effective option for customers over the long term because it: extends the useful life of this station, avoids costly reactive repairs and replacements, and minimizes lengthy customer interruptions.

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Rear Lot Supply Remediation – Royal Orchard – North (Markham)
(see System Renewal Project Business Case 150047)
Budget: $1.60MM (2018), $2.54MM (2019), $0.70MM (2020)
Forecast ISD: Phase 1 – Q4/2018 Phase 2 – Q4/2019 Phase 3 – Q4/2020
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Rear Lot Supply Remediation - Royal Orchard - North
<u>System Renewal: $1.60MM</u>
<u>Project Description and Drivers</u>

There are 37 areas within the PowerStream RZ in which customers are supplied by overhead rear lot distribution systems that are deteriorating, sub-standard, pose operational and safety risks, and supply reliability concerns.
The rear lot distribution system in the area of Royal Orchard – North, in Markham, has been identified by Alectra to be in very poor condition, and is over 50 years old and beyond the end of its useful life. Approximately 168 customers are supplied in this area.
Rear lot distribution systems are more likely to be adversely affected by major events such as storms. During the December 2013 ice storm, the inaccessibility of rear lot areas rendered restoration very difficult. Outage minutes associated with the rear lot distribution systems in the PowerStream RZ accounted for nearly 17% of the total outage minutes (29,831,573) resulting from the storm.
In addition to reliability concerns, rear lot systems currently pose safety risks to Alectra Utilities' crews. The location of rear lot systems makes them difficult to access. Since such systems are often found in heavily vegetated areas, tree trimming is often required before crews can safely access the equipment. The proximity of rear lot assets to customer facilities (e.g., storage sheds, play areas, patio decks, house extensions) also inhibits access to equipment and working around these obstacles introduces safety risks.
Rear lot construction also introduces operational inefficiencies. Much of the work must be performed manually without the use of bucket trucks and modern hydraulic equipment. The process of inspecting or troubleshooting a line requires access to multiple back yards. Additionally, due to the heavier

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<td>density of vegetation in rear lots, the frequency of tree trimming must be increased to maintain line clearances to reduce outages and allow access to equipment. All of these factors lead to longer outage troubleshooting, inspection, repair, restoration and maintenance times

<u>Project Options</u>

• The proposed solution is to convert the Royal Orchard – North area from rear lot overhead supply to front lot underground supply over a three year period from 2018 to 2020 (including both primary and secondary system components). This solution is the most effective option to eliminate safety and accessibility concerns, replace deteriorating assets, and improve reliability for customers. Alectra Utilities expects that approximately 110,000 outage minutes can be avoided per year (not considering major event days) by converting this system to front lot underground supply.

• Other options considered include: (i) maintaining the status quo (which would not address the poor asset condition of, and the reliability risks associated with, rear lot poles and lines, safety and accessibility concerns and likelihood of lengthy customer outages); (ii) replacing with new rear lot overhead plant (which would not address accessibility and reliability concerns); (iii) replacing with front lot overhead (which is not the current standard for residential supply); and (iv) introducing a hybrid design involving new underground circuits for primary conductors and renewing the rear lot overhead secondary system (which would not fully resolve concerns relating to rear lot systems).</td>
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<td>Cable Replacement – (M49) – Steeles and Fairway Heights (Markham)

(see System Renewal Project Business Case 150141)

Budget: $1.75MM (2018)

Forecast ISD: Q4/2018</td>
<td>Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive

<u>System Renewal: $1.75MM</u>

<u>Project Description and Drivers</u>

• The primary driver for this project is the need to replace sub-standard cables. In the PowerStream RZ, there are 8,388 km of underground primary cables, a portion of which are at end of its useful life and in very poor condition. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016. From 2012 to 2016, an average of 126 cable and splice interruptions per year caused 5,133,208 outage minutes for 37,474 customers. With respect to the Steeles Avenue and Fairway Heights Drive area in particular, the underground primary cable is 35 years old and at the end of its useful life. Through testing, Alectra Utilities found these cables to be in poor condition.

• A secondary driver for the project is Alectra Utilities' ongoing 13.8kV to 27.6kV conversion project. The project area is one of the remaining pockets</td>
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	of 13.8kV load supplied from John MS, via feeders John-F5 and John-F6. The performance of these feeders is many times worse relative to the SAIFI and SAIDI for the service territory. In particular, John-F5 is among the top 10 worst performing feeders out of the 322 feeders in the PowerStream RZ. Given the reliability concerns and higher losses associated with the 13.8kV system, the majority of 13.8kV load in this area has been converted to 27.6kV. Once all 13.8kV load is converted to 27.6kV, John MS can be decommissioned (since the 13.8kV supply would no longer be required), thus avoiding the costs for operating and maintaining an underutilized station. Alectra Utilities estimates approximate annual savings of $26,000 in operating and maintenance costs, as a result of station decommissioning; and $40,000 in avoided distribution line and transformer losses, as a result of the 27.6kV conversion. <u>Project Options</u> • As the recommended solution, the project is to replace the existing cable (over 3,700m in length) in the Steeles Ave and Fairway Heights Dr area. In addition, Alectra Utilities plans to convert the system from 13.8kV to 27.6kV, which requires the replacement of 18 transformers (which are not compatible with the higher operating voltage) that are also at the end of useful life. The proposed solution is preferable because it is expected to result in 81,480 outage minutes avoided per year and lower transformer and distribution line power losses. • Alternate options include: (i) allowing the cable to run to failure (which would lead to increasing failures and replacement being required under emergency situations); or (ii) rehabilitating the cable using injection technology (which would be uneconomical given that the area will be converted to 27.6kV in a few years once the other two remaining underground residential neighbourhoods are upgraded with new 27.6kV rated cable).
Cable Replacement – (V08) – Steeles and New Westminster (Vaughan) (see System Renewal Project Business Case	**Cable Replacement – (V08) - Steeles Ave and New Westminster** **<u>System Renewal: $2.50MM (2018)</u>** <u>Project Description and Drivers</u> • The PowerStream RZ has 8,388km of underground primary cables, a portion of which are end of life and in very poor condition. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI minutes in 2016. From 2012 to 2016, an average of 126 cable and splice interruptions per year caused 5,133,208 outage minutes for 37,474 customers.

150142) Budget: $2.50MM (2018), $2.64MM (2019), $2.64MM (2020) Forecast ISD: Phase 1 – Q4/2018 Phase 2 – Q4/2019 Phase 3 – Q4/2020	• The underground primary cable in the Steeles Avenue and New Westminster Drive area of Vaughan supplies 1,090 customers. It is approximately 40 years old and at the end of its useful life. It has failed 9 times in the last four years, resulting in over 350,000 customer outage minutes. <u>Project Options</u> • The proposed solution is to replace the existing cable (16,205m in length) in the Steeles and New Westminster area from 2018 to 2020 (i.e. approximately 5,402m of cable replacement per year). The project is expected to improve system reliability in the area, minimize the need for emergency reactive repairs, and result in 109,998 outage minutes avoided per year for each phase of the project. • Alternate options include: (i) allowing the cable to run to failure (which would lead to increased outages and replacement work being required in emergency situations); or (ii) rehabilitating the cable using injection technology (which was not recommended by Alectra Utilities in this case as the cable is not a suitable candidate for injection due to its deteriorated condition as identified through cable testing).
Circuit Breaker Replacement – Richmond Hill TS#1 (see System Renewal Project Business Case 150154) Budget: $1.15MM (2017), $1.13MM (2018) Forecast ISD: Phase 1 – Q4/2017 Phase 2 – Q4/2018	**Planned Circuit Breaker Replacement - Richmond Hill TS#1** **<u>System Renewal: $1.13MM</u>** <u>Project Description and Drivers</u> • Alectra Utilities has twelve transformer substations in the PowerStream RZ, one of which is the Richmond Hill TS#1 with a capacity of 150MW, serving approximately 40,000 customers. Through its asset condition assessment process, Alectra Utilities identified twelve circuit breakers which require renewal due to: technology incompatibility; history of failures; and manufacturer support no longer being provided (thus no availability of spare parts). • The circuit breakers at the Richmond Hill TS#1 are 27.6kV 1200 Amp sulphur hexafluoride feeder circuit breakers. There have been three failures at two different stations in the PowerStream RZ involving this type of circuit breaker. The most recent circuit breaker failure at Richmond Hill TS#1 affected 15,500 customers, and took over two hours to fully restore service. Kinectrics, a leading provider of solutions for high voltage testing and certification, has conducted forensic analysis of the past breaker failure and concluded that the transient recovery voltage rating of this breaker is inadequate for its application at Alectra Utilities. Further, it is the potential cause of the breaker failure. In the event of a fault, it is likely that these

	breakers will be subjected to transient recovery voltages over the breaker's rating, which may lead to a catastrophic failure of the breaker. Project Options • The proposed solution is to replace the existing circuit breakers at Richmond Hill TS#1 with HD4 circuit breakers. These are more electrically and mechanically robust than the existing circuit breakers. Further, they meet the transient recovery voltage rating requirements. Of the 12 circuit breakers requiring replacement, 50% will be replaced by the end of 2017 as part of Phase 1 of the project; the remaining 50% will be replaced by the end of 2018 as part of Phase 2. A spare circuit breaker is also being procured in each phase, bringing the total number of units being procured in the two phases to 14. Alectra is requesting funding for the second phase only. • The alternate option considered (i.e., maintaining the status quo) does not mitigate the high risk of further failures in the near term (estimated at 59,400 customer outage minutes per breaker per year, or 356,400 for the six breakers), and will lead to costly emergency repairs and prolonged customer interruptions, particularly if spare parts are not available. • The proposed solution is preferable as it will: improve reliability; reduce the likelihood of customer interruptions; and enable cost savings through equipment standardization (i.e. reduced requirement for spares given the move to a standard breaker type across the system).
Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie (see System Service Project Business Case	**Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie** **System Service: $1.30MM (2018)** Project Description and Drivers • The north Markham area[12] is supplied by two feeders (10M2 on Woodbine Ave and 12M1 on Warden Ave) with a total capacity of 40MVA, of which 30MVA is currently utilized, leaving a remaining capacity of approximately 10MVA. Known large commercial facilities coming online in 2018 will add 9.5MVA of new load using up all available capacity of the two current feeders. Beyond 2018, the projected growth associated with long-term area developments is expected to require 66 MVA of additional capacity, as a

[12] Bordered by Major Mackenzie Drive to the south, Woodbine Avenue to the west, the northerly City limits to the north, and the Robinson Creek (west of McCowan) to the east.

100229) Budget: $1.01MM (2017), $1.30MM (2018) Forecast ISD: Phase 1 – Q4/2017 Phase 2 - Q4/2018	result of the North Markham Future Urban Area expansion, and further load growth due to the Highway 404 North Development. • The planning criteria in the PowerStream RZ provide for distribution system design to enable full feeder back up capability during peak loading conditions to permit load transfer to adjacent feeders during a single contingency event (feeder power outage). Operating feeders above the applicable planning limits may lead to insufficient capacity to supply load associated with the loss of an adjacent feeder, thereby negatively impacting restoration and reliability of supply. Under single contingency conditions, without additional feeders in the north Markham area, Alectra Utilities estimates that it would be able to serve only 0.5MVA of the 9.5 MVA in new load coming online in 2018. <u>Project Options</u> • The proposed solution is to replace the existing two feeder 27.6kV pole line on Warden Avenue from 16th Ave to Major Mackenzie Drive with a four feeder pole line, extending existing feeders 12M10 and 12M11 into Markham North and increasing supply capacity by 40MVA with two new feeders by the end of 2018. An earlier phase associated with the project (replacing the pole line on Warden Ave from Highway 7 to 16th Ave) is expected to be completed by year end 2017. • An alternative solution is to defer or phase in the investment. Deferring the investment is not recommended, given that there is currently no remaining system capacity to supply anticipated growth in the area, including the 9.5MVA of confirmed new load for 2018. The phasing-in option considered was to rebuild the pole line but only install three feeders (two existing plus one new additional) in 2018 and add the second additional feeder in 2019. This option was rejected due to the higher cost associated with re-mobilization of construction crews, additional scheduled customer outages required to complete the work, and traffic impacts. Alectra Utilities estimates the cost of installing the second additional feeder in 2018 to be $100,000, compared with $130,000 to install it in 2019 when the aforementioned impacts are considered. • The proposed solution is preferred compared to other available options as it will most effectively address the short and long-term growing capacity requirements in the area. Without this investment, the existing feeders will be fully loaded in 2018. Alectra Utilities will be very limited in its ability to restore power during feeder outages.
Mill St. MS835	**<u>Mill St. MS835 Transformer Upgrade – Tottenham</u>**

Transformer Upgrade - Tottenham (see System Service Project Business Case 101068) Budget: $0.36MM (2017), $0.87MM (2018) Forecast ISD: Q4/2018	**<u>System Service: $1.23MM</u>** <u>Project Description and Drivers</u> • Two municipal substations ("MS") (Nolan MS834 and Mill MS835) currently supply approximately 2,600 residential customers in the community of Tottenham in Simcoe County. Each substation houses a single power transformer and provides backup capacity to support the Tottenham load in the event of a single contingency at the other substation. Three major residential developments, scheduled to be completed over the next four years in the Mill St and Queen St area of Tottenham, are expected to add 1,300 new customers. The growth will result in an additional 2.7 MVA peak load supplied by the two stations by 2019, bringing the total loading of the two stations to 9.6MVA. This will exceed the emergency capacity of Mill MS835 (9.1 MVA) to provide backup in the event of failure at the Nolan MS834 station. Load is expected to continue to rise beyond 2019, reaching 12 MVA by 2025/26. The transformer at Mill MS835 needs to be upgraded in 2018, in order to provide the necessary backup capacity to meet the load growth anticipated by 2019. <u>Project Options</u> • The proposed solution is to upgrade the Mill MS835 6MVA transformer to a new 10MVA 44/8.23kV transformer with a contingency maximum load rating of 15.2MVA. The existing 6MVA transformer would be used as a spare for other service areas in the PowerStream RZ. • Alectra Utilities considered five alternate solutions as follows: (i) retrofit of existing transformer by adding single-stage or dual-stage fans (deemed infeasible by Brosz & Associates due to design constraints associated with outfitting a 50 year old transformer with fans and the transformer's history of gassing suggesting deteriorated physical condition, which would also render this option a temporary solution); (ii) construction of additional feeders from MS834 (which does not address station back-up requirement); (iii) use of mobile substation for contingencies (a temporary solution that would not provide sufficient contingency back-up given the projected load growth in the area and that would be uneconomical at an estimated cost of $2.85M); (iv) installation of 3MW gas generator (which would be uneconomical at an estimated cost of $9M); (v) installation of 7.4MWh battery storage (determined to be uneconomical at a per-MWh cost of $1.8M and a total estimated cost of $13.3M). • The selected solution is preferable because it would most effectively

	address increased capacity requirements as well as reliability under single contingency scenarios. The project needs to be implemented in 2018. Without the required investment, the applicable contingency load rating of the current MS834 transformer will be exceeded as early as 2019. Given the increased loading in the area, if MS834 experiences an outage, rolling blackouts would become necessary to shed load under summer peak conditions.

<table>
<tr>
<td>Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview

(see System Service Project Business Case 101480)

Budget: $1.14MM

Forecast ISD: Q4/2018</td>
<td>Build Double Circuit 27.6kV Pole Line on 19th Ave between Leslie St and Bayview Ave

System Service: $1.14MM

<u>Project Description and Drivers</u>

• Significant growth is being projected in the North Leslie area of the Town of Richmond Hill (bounded by 19th Avenue to the north, Highway 404 to the east, Elgin Mills Rd to the south and Bayview Ave to the west), comprised of a population increase of 19,300 and an employment increase of 3,200 jobs. This projected growth will result in additional demand requirements of 20MW over the next 10 years. In the near term, approximately 500 new homes will require connection to the distribution system in the North Leslie area.

• There are currently no feeders on 19th Avenue between Leslie and Bayview to support residential and commercial developments on 19th Ave (starting in 2018). Therefore, new load in the North Leslie development area cannot be serviced unless feeders are installed to connect the new customers. A secondary concern stems from the radial configuration of the existing feeder on Leslie St, which means power is supplied from one end of the feeder only. There is no alternate supply from the other end in the event of an outage, thus giving rise to risks of prolonged outages. This issue will become more significant as the customer density in the area continues to increase.

<u>Project Options</u>

• The proposed solution is the construction of a double circuit pole line and extension of two 27.6kV circuits onto 19th Ave from Leslie St to Bayview Ave. Both 27.6kV feeders are required to be extended. When combined, these circuits provide available capacity that is sufficient to supply the immediate developments’ need, as well as creates the contingency offload for the radial feeder. This solution is preferable to the alternate option assessed (i.e., maintaining status quo and not having any circuits to connect new load), because it would most effectively meet capacity increases in the area while simultaneously addressing the current radial line issue on Leslie St between Elgin Mills Rd and 19th Ave, which would otherwise result in prolonged outages to customers in the area.

• Without the required incremental investment, Alectra Utilities will be unable to connect new customers along 19th Ave in the Leslie North area due to the current absence of feeders supplying this area.</td>
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Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 (see System Service Project Business Case 101572) Budget: $0.87MM (2017), $1.21MM (2018) Forecast ISD: Phase 1 – Q4/2017 Phase 2 – Q4/2018	**Double Circuit the existing 23M21 Single Circuit from Bayfield St & Livingstone St to Little Lake MS.** **<u>System Service: $1.21MM</u>** <u>Project Description and Drivers</u> • The City of Barrie is projecting an increase in commercial development in the Cundles Rd and Duckworth St area, resulting in a demand increase of 8.8MVA over the next five years. To meet this growth, a new 20MVA 44/13.8kV four feeder substation (Livingstone MS310), supplied by 44kV feeder 23M21, is expected to be in-service in 2018. Construction of Livingstone MS commenced in 2017 and is on plan to be placed in-service in 2018. Prior to placing Livingstone MS in-service, Little Lake MS is required to be transferred onto the extended 23M28 feeder. • A second driver is the need to ensure compliance with applicable planning limits for contingency scenarios. There is currently only one 44/13.8kV substation (Little Lake MS306) in northeast Barrie[13], which is supplied by feeders 23M21 and 23M6. Currently, 23M21 supplies 7,257 customers (including 6,529 residential), and 23M6 supplies 5,757 customers (including 4,709 residential). Each feeder provides contingency back-up, in the event an adjacent feeder in the area is lost. During 2016 summer peak, 23M6 exceeded its planning limit of 400A, and would have exceeded its thermal limit of 600A in the event of an outage on 23M21. This is prior to factoring in the 8.8MVA in new load. • With limited load transfers available (due to limited contingency capacity from 23M21 to adjacent 44kV feeders, in the event of an outage on the 23M21 during summer peak, 3MVA of load would be at risk in northeast Barrie, resulting in approximately 1,300 customers being affected by rolling blackouts. <u>Project Options</u> • The proposed solution is to extend feeder 23M28 along the existing path of 23M21 from Bayfield St and Livingstone St to Cundles Rd and Duckworth St, and transfer the supply of Little Lake MS306 from 23M21 to 23M28. This would free up capacity on 23M21 to meet the projected load growth, supply the new Livingstone MS310 and mitigate the existing thermal overloading issue under contingency conditions for the area. Transferring the supply of

[13] North-East Barrie is bounded by Hanmer Street to the north, Bayfield Street to the west, Blake Street to the south and Penetanguishene Road to the east.

	Little Lake MS306 to the 23M28 and supplying the new Livingstone MS310 from 23M21 will more evenly distribute load across both feeders. Contingency transfers from 23M21 will be accommodated by both the existing 23M6 and new feeder 23M28. • The new circuit will require the rebuild of the existing pole line along Livingstone St (from Bayfield St to Cundles Rd) and along Cundles Rd to Little Lake. Phase 1 of the work (Bayfield St to Livingstone MS located at St Vincent St and Livingstone St) is expected to be completed by the end of 2017 to coincide with the construction of Livingstone MS, and Phase 2 (east of Livingstone MS to Little Lake MS) is expected to be completed by the end of 2018. • The other option assessed (i.e.,to continue to supply Little Lake MS306 from 23M21 and Livingstone MS310 from 23M6) is not recommended. This option would result in feeder 23M6 being operated over the planning limits, and during contingency conditions, MS310-supplied customers would be at risk of rolling blackouts. This option would not accommodate the future commercial load growth in the area, nor would it provide adequate feeder capacity for load transfers in contingency conditions.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $25,136,316 is $1,834,693. Table 104 below summarizes the incremental revenue requirement for the eligible projects.

Table 104 – Incremental Revenue Requirement – PowerStream RZ

Incremental Revenue Requirement	Amount
Return on Rate base - Total	$1,411,555
Amortization	$615,688
Incremental Grossed Up PILs	($192,550)
Total	**$1,834,693**

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 105 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*, September 18, 2014, EB-2014-0219, page 23, as reproduced below.

> *"The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.13 The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy." (p.23)*

Similarly, PILs have been calculated using a full year of Capital Cost Allowance ("CCA") as 25,136,316 at 8% based on class 47 or $2,010,905.

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 X. Alectra has used the OEB 2017 Capital Module Applicable to ACM and ICM version 3.01, the most recent OEB model available at the time of filing.

Alectra Utilities also provides the calculation of the revenue requirement for each of the proposed incremental capital projects, as follows:

Table 105 – Incremental Revenue Requirement by ICM Project – PowerStream RZ

Project Description	Return on Rate base	Amortization	Incremental Grossed Up PIL's	Total Revenue Requirement
York Region Rapid Transit, VIVA Bus Rapid Transit	$631,917	$266,271	($89,303)	$808,885
System Access				**$808,885**
Station Switchgear Replacement 8th Line MS323	$77,627	$46,500	($6,396)	$117,731
Rear Lot Supply Remediation - Royal Orchard - North	$94,599	$37,728	($14,076)	$118,251
Cable Replacement – (M49) - Steeles and Fairway Heights	$103,734	$40,955	($15,574)	$129,114
Cable Replacement – (V08) - Steeles Ave and New Westminster	$148,431	$58,601	($22,284)	$184,747
Planned Circuit Breaker Replacement - Richmond Hill TS#1	$66,038	$39,558	($5,441)	$100,154
System Renewal				**$649,998**
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	$77,142	$32,922	($10,763)	$99,300
Mill Street MS835 TX Upgrade - Tottenham	$72,790	$34,110	($9,146)	$97,753
Double Circuit 27.6kV Pole Line on 19th Ave between Leslie St and Bayview Ave	$67,594	$28,103	($9,678)	$86,019
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	$71,684	$30,940	($9,887)	$92,737
System Service				**$375,810**
Total Incremental Revenue Requirement				**$1,834,693**

Rate Riders

Alectra Utilities is seeking Board approval for the ICM rate riders, for the PowerStream RZ, identified in Table 106 to recover the revenue requirement of $1,834,693 identified in Table 105 above (Attachment 34). 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 31. 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 106- Incremental Capital Funding Rate Riders – PowerStream RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.25	$0.0000	kWh
General Service under 50 kW	$0.26	$0.0002	kWh
General Service 50 to 4999 kW	$1.28	$0.0382	kW
Large Use	$55.22	$0.0204	kW
Unmetered	$0.08	$0.0002	kWh
Sentinel Lights	$0.04	$0.0897	kW
Street Lighting	$0.01	$0.0575	kW

Bill Impacts - ICM Rate Riders

Table 107 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 under 0.1% for Street Lighting to 0.3% for Unmetered.

Table 107 – ICM Bill Impacts (Total Bill) – PowerStream RZ

Rate Class	Unit	kWh	kW	ICM Rider Rate incl. HST	% Increase vs. Total Bill
Residential	kWh	750		$ 0.26	0.19%
General Service under 50 kW	kWh	2,000		$ 0.69	0.19%
General Service 50 to 4999 kW	kW	80,000	250	$ 12.24	0.09%
Large Use	kW	2,800,000	7,350	$ 231.83	0.05%
Unmetered	kWh	150		$ 0.12	0.34%
Sentinel Lights	kW	180		$ 0.05	0.10%
Street Lighting	kW	280		$ 0.01	0.02%

Alectra Utilities provides justification for each eligible capital project for PowerStream RZ in the section below.

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 2018. Each discrete project that forms part of the ICM funding request is described below. For detailed project information, please refer to the business cases included as Attachment 33.

Summary of Bill Impacts

A summary of bill impacts for the typical customer by rate class is presented in Tables 108 to 110 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 2018. Attachment 25 provides a detailed summary of the bill impacts for each customer class for 2018.

Table 108 – Distribution Bill Impacts by Rate Class – PowerStream RZ

Distribution Bill Impacts				
Customer Class	**Billing Units**	**Average Monthly Volume**	**2018 vs. 2017**	
			$	**%**
Residential	kWh	750	$ 0.54	1.92%
GS<50	kWh	2,000	$ 3.48	5.27%
GS >50	kW	250	$ 56.54	4.72%
Large User	kW	7,350	$ 502.49	2.21%
Street Lighting	kW	1	$ 0.07	0.97%

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

Table 109 – 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**	**2018 vs. 2017**	
			$	**%**
Residential	kWh	750	$ (1.41)	(4.43)%
GS<50	kWh	2,000	$ (1.52)	(2.07)%
GS >50	kW	250	$ (52.41)	(3.90)%
Large User	kW	7,350	$ (8,525.52)	(35.74)%
Street Lighting	kWh	1	$ (0.29)	(3.23)%

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

1 **Table 110– Total Bill Impacts by Rate Class (before HST) – PowerStream RZ**

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ (1.95)	(1.84)%
GS<50	kWh	2,000	$ (2.98)	(1.05)%
GS >50	kW	250	$ (115.94)	(0.96)%
Large User	kW	7,350	$ (10,730.52)	(2.74)%
Street Lighting	kWh	1	$ (0.55)	(1.18)%

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, 2018. This application impacts customers in the City of Mississauga.

Alectra Utilities has completed the 2017 IRM Rate Generator Model ("IRM Model") for the Enersource RZ provided by the OEB and will update the Application to include the 2018 IRM Rate Generator Model ("2018 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 "Filing Requirements"), dated July 14, 2016, 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 14, 2016.

Alectra Utilities also applies for incremental capital funding for the Enersource RZ in accordance with the OEB's: *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications* issued July 14, 2016 ("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

Enersource is seeking Board approval for the following:

a. 2018 distribution rates effective January 1, 2018 based on 2017 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, 2018 to December 31, 2018;

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, 2016, 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, 2016, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. An adjustment to the retail transmission service rates as provided in the *OEB's Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates* ("RTSR") effective January 1, 2018;

g. 2018 Renewable Generation Connection Rate Protection from provincial ratepayers as required under Section 79.1 of 30 the Act and Ontario Regulation 330/09;

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

i. Incremental capital rate riders effective January 1, 2018 until the next rebasing application;

j. Approval for an accounting order for a new deferral account to record incremental capital expenditures for the GO Rail Network Electrification Project; and

k. Current (i.e., 2017) rates provided in Attachment 36 be declared interim effective January 1, 2018, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2018.

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 2018 IRM filers have not yet been updated by the Board. Alectra Utilities has used a Stretch Factor of 0.15% for the Enersource RZ in this Application in accordance with the most recent PEG Report, issued on August 4, 2016. The August 2016 report placed Enersource in Group II for the purpose of calculating stretch factors for 2017.

Inflation Factor

The Industry Specific Inflation Factor for 2018 filers has not yet been updated by the Board. Enersource has used the Industry Specific Inflation Factor published for 2017 IRM filers, i.e. 1.9%, as an estimate for 2018.

Alectra Utilities will update the IRM Model for the Enersource RZ with the 2018 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 X, is 1.75%, is identified in Table 111 below.

Table 111 – Calculation of Price Cap Index – Enersource RZ

Factor	%
Inflation Factor	1.90%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.15%
Price Cap Index	**1.75%**

The Price Cap Index of 1.75% has been applied to Alectra Utilities' 2017 Service Charge and Distribution Volumetric Rate by rate class for the Enersource RZ to determine the 2018 Service Charges and Distribution Volumetric Rates. Alectra Utilities' Proposed Tariff of Rates and Charges for the Enersource RZ is filed as Attachment 37.

The Ontario government has released the OFHP. The OFHP: i) extended the payback period for items within the Global Adjustment ("GA"), and ii) transferred the funding of certain support programs, such as the Ontario Energy Support Program ("OESP") from the electricity rate base to the tax base. A portion of the bill reduction announced in the OFHP, achieved through a reduction in Regulated Price Plan ("RPP") prices, in addition to the removal of the OESP charge of $0.0011/kWh, took effect on May 1, simultaneous with the RPP changes. The final portion of the bill reduction, achieved through a further reduction in RPP prices, in addition to a reduction to the Rural and Remote Rate Protection ("RRRP") charge from $0.0021/kWh to $0.0003/kWh, took effect on July 1. Accordingly, Alectra Utilities has incorporated the removal of the OESP and reduction in the RRRP charge in the Alectra Utilities Proposed Tariff of Rates and Charges for the Brampton RZ.

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[14]: “*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[15], 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 has incorporated the third year transition adjustment for the Enersource RZ in its proposed rates for 2018. The calculation of the proposed residential fixed and variable rates is identified in Tab 16. Rev2Cost-GDPIPI of the IRM Model filed as Attachment 39.

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.

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[14] EB – 2015-0065, p 10.

[15] EB – 2016-0002, p.12.

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 $2.68 for the Enersource RZ 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 for the Enersource RZ's 10th consumption percentile. The following is a description of the method that Alectra Utilities used to derive the 10^{th} consumption percentile.

1. Total 2016 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 2016 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;
5. The data set which was comprised of 163,895 records was sorted from smallest to largest by average monthly consumption. An index of 16,390 was calculated by taking the total number of records in the data set, multiplied by 10% which corresponds to an average monthly consumption of 332 kWh, which is the 10^{th} consumption percentile for the Enersource RZ residential customers.

Alectra Utilities has provided in Table 112 below the bill impact for a Residential customer who consumes 332 kWh monthly. The monthly service charge increased by $2.68 and the bill impact for a customer at the 10th consumption percentile of electricity consumption is 3.92%.

Table 112 – 10th Consumption Percentile Residential Customer Bill Impact (332 kWh) – Enersource RZ

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**332 kWh**
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	$ 19.11	1	$ 19.11	$ 21.79	1	$ 21.79	$ 2.68	14.02%
Distribution Volumetric Rate	$ 0.0069	332	$ 2.29	$ 0.0036	332	$ 1.20	$ (1.10)	-47.83%
Fixed Rate Riders	$ 0.60	1	$ 0.60	$ 0.96	1	$ 0.96	$ 0.36	60.00%
Volumetric Rate Riders	$ -	332	$ -	-$ 0.0002	332	$ (0.07)	$ (0.07)	
Sub-Total A (excluding pass through)			$ 22.00			$ 23.88	**$ 1.88**	**8.54%**
Line Losses on Cost of Power	$ 0.0822	12	$ 0.98	$ 0.0822	12	$ 0.98	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0017	332	$ (0.56)	-$ 0.00075	332	$ (0.25)	$ 0.32	-55.88%
Low Voltage Service Charge	$ 0.0002	332	$ 0.07	$ 0.0002	332	$ 0.07	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 23.27**			**$ 25.47**	**$ 2.19**	**9.42%**
RTSR - Network	$ 0.0076	332	$ 2.52	$ 0.0077	332	$ 2.56	$ 0.03	1.32%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0063	332	$ 2.09	$ 0.0063	332	$ 2.09	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 27.89**			**$ 30.12**	**$ 2.23**	**7.98%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	344	$ 1.24	$ 0.0036	344	$ 1.24	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	344	$ 0.10	$ 0.0003	344	$ 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	216	$ 14.03	$ 0.0650	216	$ 14.03	$ -	0.00%
TOU - Mid Peak	$ 0.0950	56	$ 5.36	$ 0.0950	56	$ 5.36	$ -	0.00%
TOU - On Peak	$ 0.1320	60	$ 7.89	$ 0.1320	60	$ 7.89	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 56.76**			**$ 58.98**	**$ 2.23**	**3.92%**
HST	13%		$ 7.38	13%		$ 7.67	$ 0.29	3.92%
8% Provincial Rebate	-8%		$ (4.54)	-8%		$ (4.72)	$ (0.18)	3.92%
Total Bill on TOU			**$ 59.60**			**$ 61.93**	**$ 2.34**	**3.92%**

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 14, 2016, the OEB issued its Decision and Order in respect of the 2016 Uniform Transmission Rates ("UTRs") (EB-2015-0311). At the time of this filing, 2017 UTRs were not available. 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 113 below.

Table 113 – Current Board-Approved UTRs and STRs – Enersource RZ

UTRs	$
Network Service Rate	$3.66
Line Connection Service Rate	$0.87
Transformation Connection Service Rate	$2.02
STRs	**$**
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 39 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 2015 to 2016 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, 2016, in the amount of ($16,516,908), have been adjusted for the following items to determine the amount for disposition of ($9,127,228) as identified in Table 114, 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 must be 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 $ 2,500,544 and ($2,514,038) has been made to Account 1588 and Account 1589 respectively, to reflect RPP settlement true-up claims for 2016 that were settled in 2017. These amounts have been entered into the IRM model, Tab “3. Continuity Schedule” Column “Principal Adjustments during 2016”. See Table 114 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 2017 projected carrying charges)

Table 114 – Group 1 Account Balances for Disposition – Enersource RZ

Description	Amount
Group 1 Account Balances as of December 31, 2016	**($16,516,908)**
Subtract 2017 Annual Filing Disposition (EB-2016-0002) - Refund to Customers	($7,503,028)
RPP Settlement True-up Claims Adjustment	($13,494)
Add Projected Carrying Charges	($99,854)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**($9,127,228)**

Alectra Utilities has computed the disposition threshold for the Enersource RZ, based on the adjusted Group 1 balances to be ($0.0012)/kWh, as identified in Table 115 below. Enersource requests disposition of its Group 1 account balances in this Annual Filing.

Table 115 - Calculation of Disposition Threshold – Enersource RZ

Description	Account	Amount
Low Voltage	1550	$3,876,312
Smart Meter Entity Charge	1551	($61,134)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	$1,466,650
RSVA - Wholesale Market Service Charge excluding CBR	1580	($23,072,674)
RSVA - Retail Transmission Network Charge	1584	($2,135,901)
RSVA - Retail Transmission Connection Charge	1586	$948,217
RSVA – Power	1588	($1,503,406)
RSVA - Global Adjustment	1589	$3,970,309
Disposition and Recovery/Refund of Regulatory Balances	1595	($5,282)
Group 1 Account Balances as of December 31, 2016		**($16,516,908)**
Subtract 2017 Annual Filing Disposition (EB-2016-0002) - Refund to Customers		($7,503,028)
RPP Settlement True-up Claims Adjustment		($13,494)
Add Projected Carrying Charges		($99,854)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**($9,127,228)**
2016 kWhs		7,328,256,775
Threshold Test $/kWh		**($0.0012)**

Alectra Utilities has completed Tab 3. Continuity Schedule of the IRM Model for the Enersource RZ filed as Attachment 39. Alectra Utilities has reconciled the Group 1 balances for Enersource filed in the 2016 RRR, section 2.1.7 as identified in Table 116 below. Alectra Utilities confirms that the last Board approved balance of ($7,503,028) for the Enersource RZ has been transferred to Account 1595 (as identified in Enersource's IRM Application EB-2016-0002). Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2016 RRR, section 2.1.5.4. Enersource relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rate of 1.10% was relied upon to calculate forecasted interest for 2017. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

Table 116 – Deferral and Variance Account Reconciliation – Enersource RZ

Account Description	Account	Principal Amounts as of Dec 31, 2016	Carrying Charges to Dec 31, 2016	Principal Disposition during 2017 - instructed by Board EB-2016-0002	Interest Disposition during 2017 - instructed by Board EB-2016-0002	Projected Carrying Charges to Dec 31, 2017	Total Disposition before RPP True-Up Adjustment	RPP Settlement True-up Claims Adjustment	Projected Carrying Charges to December 31, 2017	Total Disposition
Group 1 Accounts:										
Low Voltage	1550	3,835,970	40,343	(1,545,688)	(24,215)	25,193	2,331,602			2,331,602
Smart Meter Entity Charge	1551	(60,375)	(759)	26,931	434	(368)	(34,137)			(34,137)
RSVA - Wholesale Market Service Charge - CBR B	1580	1,444,449	22,200	(1,719,664)	(24,645)	(3,027)	(280,686)			(280,686)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(22,779,156)	(293,518)	15,911,140	237,452	(75,548)	(6,999,629)			(6,999,629)
RSVA - Retail Transmission Network Charge	1584	(2,126,009)	(9,892)	1,557,808	19,862	(6,250)	(564,482)			(564,482)
RSVA - Retail Transmission Connection Charge	1586	927,377	20,841	(593,535)	(11,846)	3,672	346,508			346,508
RSVA - Power	1588	(1,489,157)	(14,249)	(1,362,016)	(7,363)	(31,363)	(2,904,148)	2,500,544	27,506	(376,097)
Sub-total not including RSVA Power Global Adjustment		(20,246,901)	(235,034)	12,274,977	189,678	(87,691)	(8,104,971)	2,500,544	27,506	(5,576,921)
RSVA - Power Global Adjustment (balance to June 30, 2016)	1589	991,969	100,290	(4,890,994)	(70,633)	(42,889)	(3,912,258)			(3,912,258)
RSVA - Power Global Adjustment (balance from July 1, 2016)	1589	2,865,358	12,692	-	-	31,519	2,909,569	(2,514,038)	(27,654)	367,877
										$0
Total including RSVA Power Global Adjustment		(16,389,574)	(122,052)	7,383,983	119,045	(99,062)	(9,107,659)	(13,494)	(148)	(9,121,302)
Disposition and Recovery/Refund of Regulatory Balances (2014) - (IRM 2016)	1595	(58,585)	53,303	-	-	(644)	(5,926)			(5,926)
Total 1595		(58,585)	53,303	-	-	(644)	(5,926)			(5,926)
Total Group 1		**(16,448,159)**	**(68,749)**	**7,383,983**	**119,045**	**(99,706)**	**(9,113,586)**	**(13,494)**	**(148)**	**(9,127,228)**
Total Amount for Disposition		**(16,448,159)**	**(68,749)**	**7,383,983**	**119,045**	**(99,706)**	**(9,113,586)**	**(13,494)**	**(148)**	**(9,127,228)**

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. Enersource 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 two Enersource RZ customers who qualified as Class A customers effective July 1, 2016 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, 2016; and paid GA and CBR as Class A customers from July 1, 2016 to December 31, 2016. 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, 2016 to June 30, 2016).

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.

The total GA balance to be disposed of is $1,002,689, of which $992,525 will be disposed of via rate riders; and $10,164 will be disposed of via specific bill adjustments for the two new Class A customers as discussed above. Tab “6a GA Allocation Class A” in the IRM Model identify the detailed calculation of the bill adjustment of $10,164.

The total CBR balance to be disposed of is $280,686, of which $279,010 will be disposed of via rate rider; and $1,676 will be disposed of via specific bill adjustments for the two new Class A customers as discussed above. Tab “CBR 1580 Sub-Account” in the IRM Model identify the detailed calculation of the bill adjustment of $1,676.

Alectra Utilities requests disposition of its GA balance for the Enersource RZ of $10,164 and its CBR balance of $1,676 related to its two new Class A customers (effective July 1, 2016) through the bill adjustments identified in the IRM Model.

Table 117 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Table 117 –Disposition of GA and CBR Balances – Enersource RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($3,508,454)
Global Adjustment - New Class A Customers July 1/2016	($35,927)
Global Adjustment - New Class B Customers July 1/2016	$0
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**($3,544,381)**
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2016- Dec 31/2016	($279,010)
Capacity Based Recovery - New Class A Customers July 1/2016	($1,676)
Capacity Based Recovery - New Class B Customers July 1/2016	$0
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**($280,686)**

A summary of the rate riders applicable to each group of customers is identified in Table 118 below.

Table 118 – 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, 2016 - Dec 31, 2016)	x	x			
Class B non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class A (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers					
Class B non-RPP (Jan 1, 2016 - Dec 31, 2016) 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 and the remaining balance in Account 1595 related to Enersource's 2017 IRM Application (EB-2016-0002).

Class A customers (who were Class A from January 1 – December 31, 2016) 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 2016) 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 2016) 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, 2016) 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 119 below. The amount to be disposed of by rate rider is ($9,089,625) and the amount to be disposed of via customer specific bill adjustments is ($37,603) (credits of $35,927 GA and $1,676 CBR).

Table 119 – Group 1 Disposition by Customer Group – Enersource RZ

Description	Account	Amount
Low Voltage	1550	$2,331,602
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	($34,137)
Retail Transmission Network Charge	1584	($564,482)
Retail Transmission Connection Charge	1586	$346,508
IRM 16	1588	($5,926)
All Customers - DVA Rate Rider 1		**$2,073,565**
Power	1588	($376,097)
Wholesale Market Service Charge excluding CBR	1580	($6,999,629)
All Customers ex WMPs - DVA Rate Rider 2		**($7,375,727)**
Wholesale Market Service Charge - CBR Class B	1580	($279,010)
Wholesale Market Service Charge - New Class A/B Customers July 1/2016		($1,676)
All Class A Customers ex WMPs - CBR B Bill Adjustment	**1580**	**($280,686)**
Global Adjustment - Non-RPP Class B Customers Jan 1/2016 -Dec 31/2016	1589	($3,508,454)
Global Adjustment - New Class A/B Customers July 1/2016	1589	($35,927)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**($3,544,381)**
Total (Repayment to)/Recovery from Customers		**($9,127,228)**
Disposition via Rate Rider		($9,089,625)
Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2016		($35,927)
Disposition via Customer Specific Bill Adjustments - CBR for Class A customers only a portion of 2016		($1,676)

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2016 actuals reported in Enersource's RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016.

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 39. Table 120 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 120 – Proposed Rate Riders by Class – Enersource RZ

Customer Class	Deferral/Variance Accounts Rate Rider		Deferral/Variance Accounts Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B from Jan 1 - Dec 31, 2016		CBR B Rate Rider Class B Consumer from Jan 1 - Dec 31, 2016	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
RESIDENTIAL	(0.0007)				(0.0010)		(0.00005)	
GENERAL SERVICE <50 KW	(0.0007)				(0.0010)		(0.00005)	
GENERAL SERVICE 50-499 KW		0.0999		(0.3516)	(0.0010)			(0.01596)
GENERAL SERVICE 500-4999 KW		0.1265		(0.4437)	(0.0010)			(0.01987)
LARGE USE		(0.4029)			0.0000			0.00000
UNMETERED & SCATTERED LOADS	(0.0007)				(0.0010)		(0.00005)	
STREET LIGHTING		(0.2599)			(0.0010)			(0.01645)

Alectra Utilities requests disposition of its adjusted Group 1 balances for the Enersource RZ of ($9,089,625), identified in Table 119, through the rate riders identified in Table 120 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.

For a typical RPP Residential customer using 750 kWh/month, the total bill impact of the proposed Group 1 rate riders is an increase of ($0.56)/month or (0.52%) on total bill.

Alectra Utilities understands that OEB staff are testing a new Global Adjustment Analysis work form for the 2018 IRM process. At the time of this filing, a final work form is not available. Alectra Utilities anticipates providing the completed workform once it is released by the OEB.

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 121 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 121 – 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 - Horizon 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

Class A Customers: 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 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.

Establishment of New Deferral and Variance Accounts

Alectra Utilities requests approval for an accounting order to establish a new deferral account for the Enersource RZ to record the financial impacts resulting from the MetroLinx Crossing Remediation Project. The OEB states that:

> *In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:*
>
> *Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.*
>
> *Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.*
>
> *Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.*

The Metrolinx Regional Express Rail (“RER”) Electrification program is an infrastructure roll out plan by Metrolinx that will entail the conversion of 6 out of 8 GO rail corridors from diesel to electric propulsion. This will help to transform the way the region moves by building a seamless, convenient and integrated transit network across the Greater Toronto and Hamilton Area (“GTHA”).

As part of this project, GO Transit plans to enable 15-minute service on most corridors with electrified trains, increasing the frequency of service in the GTHA by four times the current number of GO train trips on evenings and weekends, and twice the number of trips during peak periods. The program will involve planning, design and implementation of a traction power supply system and power distribution components including Overhead Catenary System (“OCS”) along the rail corridors to be electrified.

The OCS is comprised of portal/cantilever structures that support wires on assemblies. The electric train is supplied power through the pantograph which connects to the contact wire. With the addition of the cantilever structures for electrification, the existing overhead crossings will not meet the clearance and safety standards for the existing poles lines and will have to be remediated by either moving the plant to underground or rebuilding the crossings overhead to provide adequate clearances. In addition, there are some grade separation projects that will be required.

Alectra Utilities has determined that all of the overhead crossings along the Lakeshore and Kitchener corridor are in conflict with the OCS system for the GO electrification and will need to be remediated by either rebuilding the overhead system with increased clearances by utilizing taller poles or by moving the existing lines underground. Metrolinx's Electrification Third Party Utility Team has identified a total of 28 crossings and 7 parallel lines in the Enersource RZ along the Lakeshore and Kitchener corridors that are in conflict.

Alectra Utilities is assessing the impact and options for mitigation of the identified conflicts in the Enersource RZ. Due to restrictions on height of the existing equipment and limitations due to maintenance schedule window, it was determined that the best option for mitigation of the overhead primary distribution crossings is to convert them to underground crossings.

The timelines for tender is scheduled for 2019 and actual construction is expected to start in 2020. Metrolinx has informed Alectra Utilities that several crossings in the Enersource RZ will need to be remediated between 2017-2020. Based on the proposed schedule, Alectra Utilities anticipates 10 crossings may need to be remediated in 2018 in order to align with Metrolinx's schedule for construction. As the final design and identification of the specific number crossings to be remediated have not been finalized by Metrolinx, project costs have not been developed. Alectra Utilities continues to monitor the progress and timelines of the project schedule as they are dependent on Metrolinx.

The requested new deferral account satisfies the Board's eligibility criteria:

Causation – Alectra Utilities can confirm that the forecasted underground and overhead capital expenditures required to support the Metrolinx Crossings Remediation Project are not included in the Enersource RZ DSP and no previous recovery has been sought or approved by the Board for this expenditure.

Materiality – At the timing of filing, a final project schedule outlining the crossings to be remediated in 2018 and which are in conflict with Metrolinx's OCS system for the GO electrification has not been provided. The existing Metrolinx Crossing Agreements specify that the utility is solely responsible for the relocation costs for its distribution system assets.

Prudence – Alectra Utilities is obligated to remove or relocate certain parts of its distribution system in the vicinity of the rail lines. The Metrolinx Crossing Agreement provides that *"should it become necessary or expedient for the purposes of repair or improvement of the railway line that the Works be temporarily removed or relocated, the Applicant shall upon request of the Owner and at the sole cost of the Applicant forthwith remove or relocate the Works".*

Alectra Utilities has filed at Attachment 40 a proposed accounting order for the Enersource RZ which includes a description of the mechanics of the account, examples of the general ledger entries and the proposed manner in which to dispose of the account.

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 2015 and provides an updated estimate for 2017 and 2018 Renewable Generation Connection funding and costs.

Alectra Utilities continues to connect renewable generators to its distribution system in the Enersource RZ. Table 122 below provides the total number of FIT and microFIT applications received by Alectra Utilities for the Enersource RZ as of the end of March, 2017. 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 122 also provides a summary of the number of renewable energy projects connected as of the end of March, 2017, and the corresponding total installed capacity for those projects since 2010.

Table 122: Renewable Connections as of March 31, 2017 – Enersource RZ

Type of Renewable Generation	Number of Applications Received	Total Number of Projects Connected	Total kW of Projects Connected
MicroFIT (≤10 kW)	1,755	485	3,776
FIT (>10 kW)	1,136	91	16,251
Total	**2,891**	**576**	**20,027**

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 123 below.

Table 123: Actual/Forecast of Renewable Generation Project Connections – Enersource RZ

	2013	2014	2015	2016	March 2017 YTD	2017 Forecast	2018 Forecast
Actual/Forecast Number of Renewable Generation Projects Connected							
microFIT	64	41	119	117	24	75	30
FIT	9	26	16	9	15	47	10
Total	**73**	**67**	**135**	**126**	**39**	**122**	**40**
Actual/Forecast Total kW of Renewable Generation Projects Connected (kW)*							
microFIT	420	326	1,141	997	170	562	225
FIT	2,100	4,412	2,994	1,712	2,123	8200	3500
Total	**2520**	**4738**	**4135**	**2709**	**2293**	**8762**	**3725**
Actual/Forecast Number of Renewable Generation Projects Applications Received							
microFIT	212	176	383	165	51	130	100
FIT	195	62	227	34	1	10	0
Total	**407**	**238**	**610**	**199**	**52**	**140**	**100**

The forecasted microFIT connections in 2017 have increased from 65 projects, as outlined in the original forecast provided in 2017 IRM Rate Application (EB-2016-0002), to 75 projects, as shown in Table 123, mainly as a result of increased customer interest in the program.

The forecasted microFIT connections in 2018 are expected to be 30 projects. The 2018 forecast only accounts for projects initiated in 2017 and expected to be completed in 2018 as the procurement of the microFIT projects comes to an end in 2017.

The forecast for FIT projects for 2017 has increased to 47 projects, compared to 25 projects originally forecasted for 2017. This is due to the delay of several projects that were originally projected to be completed in 2016. The new projection date for the completion of these delayed projects is for the fall of 2017.

Alectra Utilities is requesting the collection of renewable generation funding for the Enersource RZ of $133,384 in 2018, or $11,115 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 2011 through 2015. The total amount requested for disposition is a debit of $2,146,406 including forecasted carrying charges of $105,256 through to December 31, 2017. Enersource's actual savings from CDM activities for 2011 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Enersource's most recent application for the recovery of lost revenues due to CDM activities was filed in EB-2013-0024. In that proceeding, the Board approved Enersource's request to recover lost revenues from persisting historical impacts of pre-2011 CDM programs in 2011 and 2012.

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 $2,146,406, 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 14, 2016, 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:

(iii) 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

(iv) 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 2011 to 2014 and 2015 are filed as Attachments 43 and 44 respectively.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2016. Alectra Utilities proposes to dispose of its 2016 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 2016 balances as mentioned previously.

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2011 to December 31, 2015 for the Enersource RZ resulting from the following:

(iii) Incremental savings from IESO-funded CDM programs implemented in 2011 to 2015, including persistence of these savings through 2015.

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 124 identified below.

1 **Table 124 – 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	kWh	kW
2011	$0.0115	$0.0113	$4.1209	$2.0436	$2.8597	$10.0035
2012	$0.0115	$0.0113	$4.1332	$2.0455	$2.8667	$10.0167
2013	$0.0131	$0.0115	$4.1851	$2.1572	$2.6656	$10.5033
2014	$0.0131	$0.0117	$4.2502	$2.1870	$2.7145	$10.6192
2015	$0.0133	$0.0119	$4.3118	$2.2189	$2.7539	$10.7732

2 Alectra Utilities' Enersource RZ's LRAMVA threshold approved in Enersource's 2013 Cost of
3 Service Application (EB-2012-0033) is used as the comparator against actual savings for the
4 lost revenue calculation for 2011 to 2015. The LRAMVA thresholds are provided in Tab "2.
5 LRAMVA Threshold" of the LRAMVA work form and in Table 125 identified below.

Table 125 – 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	kWh	kW
2011		0	0	0	0	0	0
2012		0	0	0	0	0	0
2013	2013	35,842,920	39,519,293	19,284	16,135	15,417	61,001
2014	2013	35,842,920	39,519,293	19,284	16,135	15,417	61,001
2015	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, 2011 to December 31, 2015 in the LRAMVA work form using the OEB's annual prescribed interest rates of 1.47% to March 31, 2015 and 1.1% thereafter as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $2,146,406, representing a principal balance of $2,041,150 and carrying charges of $105,526.

Alectra Utilities has provided a summary of its lost revenue calculations for the Enersource RZ by year for each rate class in Tables 126 and 127 below, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

Table 126 – LRAMVA Totals by Rate Class – Enersource RZ

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	($334,017)	($10,663)	($344,681)
GS<50 kW	kWh	$342,832	$25,494	$368,326
General Service 50 to 499 kW	kW	$2,543,868	$115,001	$2,658,870
General Service 500 to 4,999 kW	kW	$594,944	$26,396	$621,339
Large Use	kW	$150,684	$5,640	$156,325
Street Lighting	kW	($1,257,161)	($56,612)	($1,313,773)
Total		**$2,041,150**	**$105,256**	**$2,146,406**

Table 127 – LRAMVA by Year and Rate Class – Enersource RZ

Description	Residential	GS<50 kW	General Service 50 to 499 kW	General Service 500 to 4,999 kW	Large Use	Street Lighting	Total
	kWh	kWh	kW	kW	kW	kW	
2011 Actuals	$67,389	$156,920	$162,769	$37,080	$1,071	$0	$425,230
2011 Forecast	$0	$0	$0	$0	$0	$0	$0
2011 LRAM Balance	**$67,389**	**$156,920**	**$162,769**	**$37,080**	**$1,071**	**$0**	**$425,230**
2012 Actuals	$112,891	$256,184	$349,503	$78,877	$6,547	$0	$804,001
2012 Forecast	$0	$0	$0	$0	$0	$0	$0
2012 LRAM Balance	**$112,891**	**$256,184**	**$349,503**	**$78,877**	**$6,547**	**$0**	**$804,001**
2013 Actuals	$181,736	$331,128	$522,335	$133,139	$64,721	$48,893	$1,281,952
2013 Forecast	($469,542)	($454,472)	($80,705)	($34,806)	($41,096)	($640,712)	($1,721,333)
2013 LRAM Balance	**($287,807)**	**($123,344)**	**$441,629**	**$98,333**	**$23,625**	**($591,818)**	**($439,381)**
2014 Actuals	$306,458	$435,312	$757,547	$179,976	$81,992	$219,231	$1,980,516
2014 Forecast	($469,542)	($462,376)	($81,961)	($35,287)	($41,849)	($647,782)	($1,738,797)
2014 LRAM Balance	**($163,084)**	**($27,064)**	**$675,586**	**$144,689**	**$40,143**	**($428,551)**	**$241,719**
2015 Actuals	$413,305	$550,416	$997,529	$271,767	$121,755	$420,385	$2,775,156
2015 Forecast	($476,711)	($470,280)	($83,149)	($35,802)	($42,457)	($657,176)	($1,765,574)
2015 LRAM Balance	**($63,406)**	**$80,136**	**$914,380**	**$235,965**	**$79,298**	**($236,791)**	**$1,009,582**
Carrying Charges	**($10,663)**	**$25,494**	**$115,001**	**$26,396**	**$5,640**	**($56,612)**	**$105,256**
Total LRAMVA Balance	**($344,681)**	**$368,326**	**$2,658,870**	**$621,339**	**$156,325**	**($1,313,773)**	**$2,146,406**

The proposed rate riders that result from the disposition of Account 1568, LRAM Variance Account, is identified in Table 128 below and included in Tab “8. Calculation of Def-Var RR” in the IRM Model.

Table 128 – LRAMVA Rate Riders – Enersource RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.00	($0.0002)	kWh
GS<50 kW	$0.00	$0.0006	kWh
General Service 50 to 499 kW	$0.00	$0.4416	kW
General Service 500 to 4,999 kW	$0.00	$0.1357	kW
Large Use	$0.00	0.0883	kW
Street Lighting	$0.00	($28.7451)	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 rates for 2016 and 2017 are 26.50% and are not expected to change. Therefore, there is no shared tax savings in this rate application.

Incremental Capital Module

Overview

Alectra Utilities has OEB-reviewed Distribution System Plans ("DSPs") for the Horizon Utilities (2015-2019), Brampton (2015-2019) and PowerStream (2016-2020) rate zones, in accordance with the RRFE. A DSP for the Enersource RZ is included as part of this application.

Alectra Utilities is seeking Board approval for incremental capital funding for the Enersource RZ for 2018, through distribution rate riders as identified in Attachment 45. Alectra Utilities has capital investment needs for the Enersource RZ that are not funded through existing distribution rates. The needs fall into the following categories: system renewal, system access, and system service. The Enersource RZ is on Price Cap IR for the purpose of setting 2018 electricity distribution rates. Therefore, the ICM is available for the Enersource RZ. Enersource provides justification for the request for incremental capital below.

Enersource RZ DSP

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 and findings for the Enersource RZ, 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 Enersource RZ's Comprehensive Asset Management Policy ("CAMP") (attached as Appendix A of the DSP) underpinned the asset management strategy and practices that led to the development of its DSP. The CAMP is a set of principles for the stewardship and management of Enersource RZ assets to ensure an optimal balance between reliability performance and overall costs. Going forward, Alectra Utilities plans to harmonize its asset management practices across all four Rate Zones.

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.

The Enersource RZ's 2018-2022 DSP is filed with this application. The DSP is compliant with the OEB's *Chapter 5 Filing Requirements for Transmission and Distribution Applications* ("Chapter 5 Requirements"); it is also aligned with the RRFE. 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, as follows:

Operational Risk (related RRFE values: Customer Focus and Operational Effectiveness) – Over the last few years, SAIDI and SAIFI have been trending upward, which reflects the deteriorating condition of distribution assets and the resulting impact on service quality. The Enersource RZ DSP includes a number of projects to address this negative trend in overall system performance and customer service quality.

Environmental Risk (related RRFE value: Public Policy Responsiveness) – 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.

Financial Risk (related RRFE value: Financial Performance) – 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.

Safety and Regulatory Risk (related RRFE values: Customer Focus and Public Policy Responsiveness) – Customers, employees and the public must be protected from hazards that may arise in connection with the Enersource RZ's assets. In this regard, Alectra Utilities is replacing potentially leaking transformers to avoid health and safety impact on those in contact with these assets. In addition, a significant portion of Mississauga's underground system (which contains cables that are at the end of useful life and were built according to outdated standards) is prone to failure and pose a safety risk to Alectra Utilities workers and the public. The pressing need to address the risks associated with these older and deteriorated systems was a crucial consideration in establishing the Enersource RZ DSP.

The DSP includes the capital expenditure plan as provided in Table 129.

Table 129: Enersource RZ Capital Expenditure Plan 2018-2022 ($000s) – Enersource RZ

Category	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
System Access	$8,114	$11,679	$13,797	$13,812	$12,752	$10,812
System Renewal	$37,386	$40,910	$42,150	$41,520	$40,160	$36,940
System Service	$11,147	$13,422	$13,407	$13,717	$13,522	$14,007
General Plant	$6,798	$6,672	$7,580	$8,411	$6,753	$5,869
Total Enersource RZ	**$63,445**	**$72,683**	**$76,933**	**$77,459**	**$73,186**	**$67,627**

Asset Management Practices

The Enersource RZ's 2018-2022 DSP began with an assessment of external drivers (e.g. regulatory requirements, regional planning, renewable generation), internal drivers (e.g. asset conditions and performance, corporate objectives, service quality targets), as well as other relevant investment considerations (e.g. customer preferences, system enhancement needs, and technical requirements). Based on these inputs, Alectra Utilities identified the investment needs and potential projects for the Enersource RZ.

The DSP includes both mandatory and discretionary investments. Mandatory investments are those driven by statutory, regulatory or contractual obligations that Alectra Utilities must meet in the Enersource RZ. All other projects are discretionary. Each project was categorized, based on primary investment drivers, using the investment categories set out by the Chapter 5 Requirements (e.g. System Access, System Renewal, System Service, General Plant).

Based on the evaluation and comparison of available technical alternatives for each project, Alectra Utilities identified the preferable solution that addresses the relevant business risks and balances competing priorities in the most efficient and cost effective manner (though not necessarily least cost).

Once the proposed projects were gathered from all business units, Alectra Utilities prioritized its investment portfolio, ranking projects by their ability to address the most important investment needs and their expected impact on underlying business values (i.e. regulatory and public policy responsiveness, operational effectiveness, customer focus, and financial performance).

Mandatory, non-discretionary, investments were prioritized first. For both mandatory and discretionary projects, a key input into the capital investment planning process is the estimated financial impact resulting from the proposed projects. More specifically, individual projects were evaluated based on the following three considerations:

- Cost efficiency, which relates to a project's potential to lead to cost savings or avoidance;
- The ongoing costs expected to be incurred as the result of a project; and
- The project's expected rate impact.

Once determined, the expected financial impact, along with other relevant considerations such as customer preferences and resource availability, helped Alectra Utilities ensure that its overall investment portfolio is appropriately paced throughout the DSP period.

Capital Expenditure Portfolio

The Enersource RZ's 2018-2022 DSP identifies projects in the following four investment categories:

- System access investments are necessary for the expansion and modification (including asset relocation) of Enersource RZ's distribution system, in order to provide customers access to adequate distribution services. Key drivers for system access investments include intensification growth in the downtown core of Mississauga and the implementation of the Light Rail Transit ("LRT") system.
- System renewal investments address assets performing at a sub-standard level. Alectra Utilities identified areas that required renewal based on asset condition assessment, inspection records and system performance trends. Alectra Utilities also took into account the consequences of asset performance deterioration or failure, in reference to asset performance-related operational targets, asset lifecycle optimization practices and the number of customers affected by asset failures.

- System service investments needs are driven by: i) load growth in specific areas of the Enersource RZ service area, which cannot be met by the current capacity of the distribution system; and ii) system operational constraints that need to be eliminated. City of Mississauga development plans, regional planning processes, and technological innovation are key drivers to improve operational efficiency.
- General plant investment support requirements for business operations and address findings from condition assessments of facilities and fleet assets.

The main distribution system investments that underpin the DSP reflect three key drivers: i) the need to address load growth drivers in specific areas of the city and capital works made necessary by major infrastructure projects such as the LRT; ii) the need to address the deteriorating condition of a portion of the Enersource RZ's distribution assets, and iii) the need to mitigate, in a timely manner, environmental risks stemming from distribution transformers that exhibit signs of oil leaks**.** Each of these main drivers is discussed below, followed by a summary of the overall investment portfolio for the DSP planning period.

<u>Investments Needs to Address Growth and Infrastructure Development</u>

The City of Mississauga is now in a post-greenfield phase. Population and employment growth is projected to continue with ongoing intensification and redevelopment. Growth projections from the City of Mississauga indicate significant growth in the downtown core as well as continued employment growth in certain business districts. The City established the Downtown 21 Master Plan for creating a vibrant and pedestrian-oriented downtown core. The plan projects population and employment increases in the area of 69,000 and 71,400, respectively, by 2031.

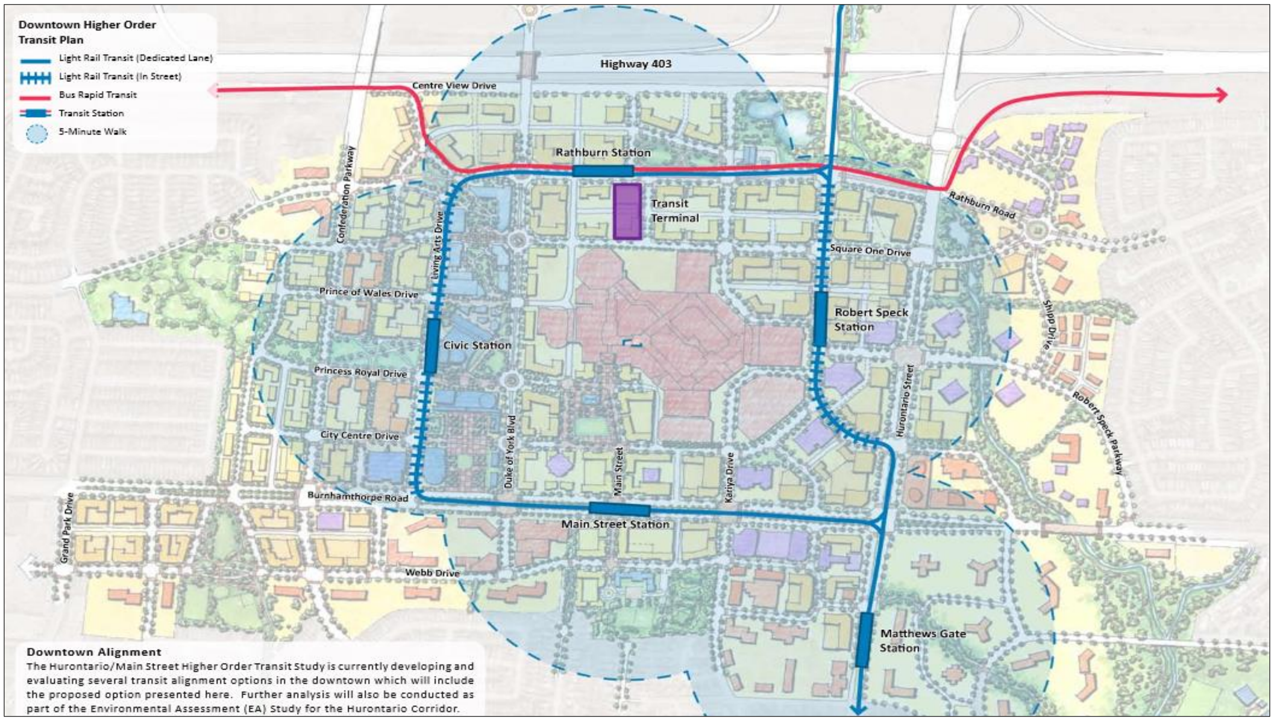
Currently, approximately 65 buildings in the downtown core are serviced by three substations, which accommodate an aggregate demand of 117MW. Based on the above-noted growth projections and taking into account the potential impact of CDM, Alectra Utilities projects a load increase of 172MW in the area.

To address these system access and system service needs, Alectra Utilities plans to increase distribution capacity in the downtown core by building two new substations. The DSP outlines the need to construct Webb MS in the southern portion of the downtown core and Duke MS in the northern portion.

Due to the high-density layout and emphasis on pedestrian-friendliness, Alectra Utilities is required to adopt underground designs for all downtown core electrical infrastructure. To this end, installing the underground system before construction starts on the permanent buildings would be much more efficient and economical. This avoids issues with space in the common trenches, prevents expensive repairs and restoration to new road surfaces, sidewalks and landscaping, reduces disruption to existing customers in the area, and eliminates the need for expensive rental of generators.

In order to support and mobilize the high-density population projected for the downtown core, the City of Mississauga has a plan to supplement existing public transportation with higher order transit, including the Light Rail Transit ("LRT") and Bus Rapid Transit ("BRT"). Figure 1 below identifies the combined Downtown 21 and high order transit plans.

Figure 1- Downtown Core Plans with Transportation Infrastructure



In April 2015, the Province of Ontario announced that the LRT project in Mississauga would move ahead in support of the Moving Ontario Forward plan. The construction of the LRT is expected to start in 2018 and the in-service date is expected in 2022. The Enersource RZ DSP reflects system access investments to address the construction of the LRT as well as system access and system service projects to accommodate the projected growth in the downtown core.

The DSP also includes the capital investment necessary to connect and service renewable generation in the Enersource RZ. At the end of 2016, 554 renewable generators totaling 23.5 MW in generation capacity were already connected to Enersource RZ's distribution system. The DSP includes investments to support 326 additional renewable generators (with projected capacity of 42.6MW) onto the system by 2022. Alectra Utilities will continue to enable and support the connection of renewable generators in the Enersource RZ, while ensuring that service quality to existing customers is maintained.

In order to more effectively and efficiently meet the growth projected in specific areas of the city, Alectra Utilities considered the impact of CDM as well as advanced grid infrastructure technologies. Examples of such investments include the inclusion of additional remote-capable automation equipment in the underground and overhead systems and integrating such capability in the Enersource RZ's Outage Management System ("OMS"). The integration of automated distribution equipment into the OMS will enhance real-time visibility and control of feeders, substations and switchgear to promptly identify system interruptions.

Investment Needs to Address System Renewal

As of 2016, the City of Mississauga has a population of over 750,000 and is the sixth largest city in Canada. Much of the growth in Mississauga occurred between the 1960s and 1990s. During that period, the City's population increased from approximately 74,000 to 463,000. A significant portion of the Enersource RZ's asset infrastructure was installed during this period of rapid economic expansion, and is now approaching 50 years in-service and nearing the end of its useful life. Enersource RZ has been able to extend the life of this equipment through careful management and prudent investment. However, given their condition, a growing number of assets require timely replacement.

The Enersource RZ DSP outlines the company's asset lifecycle optimization policy and practices, which guide the decisions regarding asset maintenance and renewal. These practices are based on a balance of top-down and bottom-up assessments. Bottom-up assessments utilize information from health index condition assessments as well as information attained from routine inspection and maintenance.

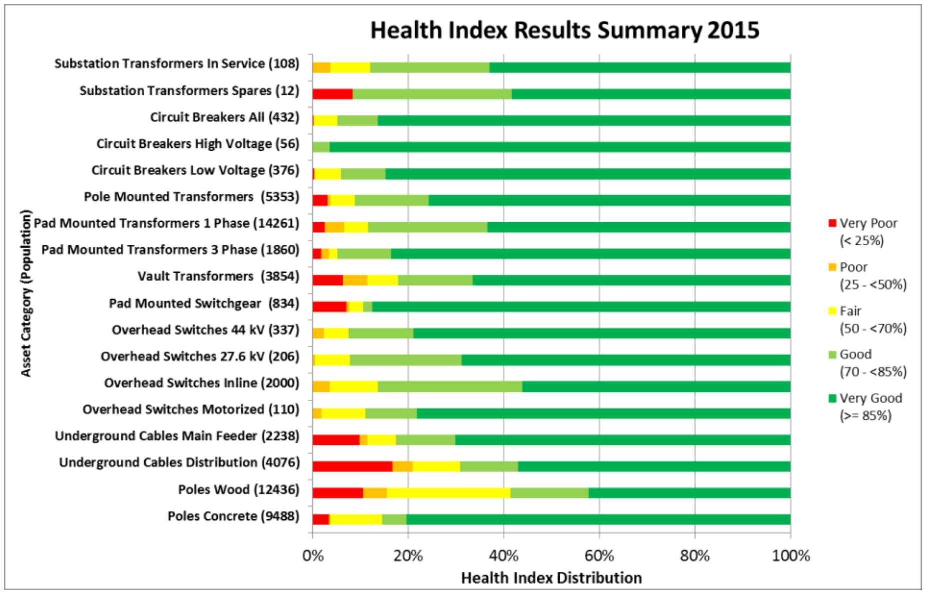
Through such assessments, Alectra Utilities identifies either an immediate need to repair or replace the asset (e.g. due to significant hazard or imminent failure), or further action to be considered in system renewal planning. These investment needs are also evaluated on the basis of top-down considerations, including the prudent balance of operational and economic factors, alignment with business values, customer preferences, rate impacts and overall risk mitigation.

In 2016, Kinectrics was retained to provide an Asset Health Index ("HI") Condition Assessment of major distribution assets including transformers, underground cables, poles, circuit breakers and switchgear based on asset information and records as of December 2015. The HI results in the Kinectrics report demonstrated the significant improvements made in the Enersource RZ with respect to asset inspection programs and data collection, including more frequent and detailed inspections, more rigorous review of outage data, and the use of additional analytical methods. Key HI results indicated that the underground cables and wood poles in the Enersource RZ had the highest proportion of assets in poor or very poor condition.

The Enersource RZ's underground cables include main feeder and distribution cables. Main feeder cables supply substations as well as switchgear units. The HI results identified 12% of main feeder cables (i.e. 256 km of 2,239 km feeder cables in-service) as being in poor or very poor condition. Distribution cables connect to transformers that supply customers. The HI results identified 21% of distribution (i.e. 851 km of 4,076 km distribution cable in-service) as being in poor or very poor condition.

The Enersource RZ's distribution poles include wood and concrete poles. According to the HI results, 16% of wood poles (i.e. 1,936 of 12,436 wood poles in service), and 3% of concrete poles (or 326 of 9,488 concrete poles in service) are in poor or very poor condition. Figure 2 illustrates the HI results for distribution system assets based on 2015 asset records and data.

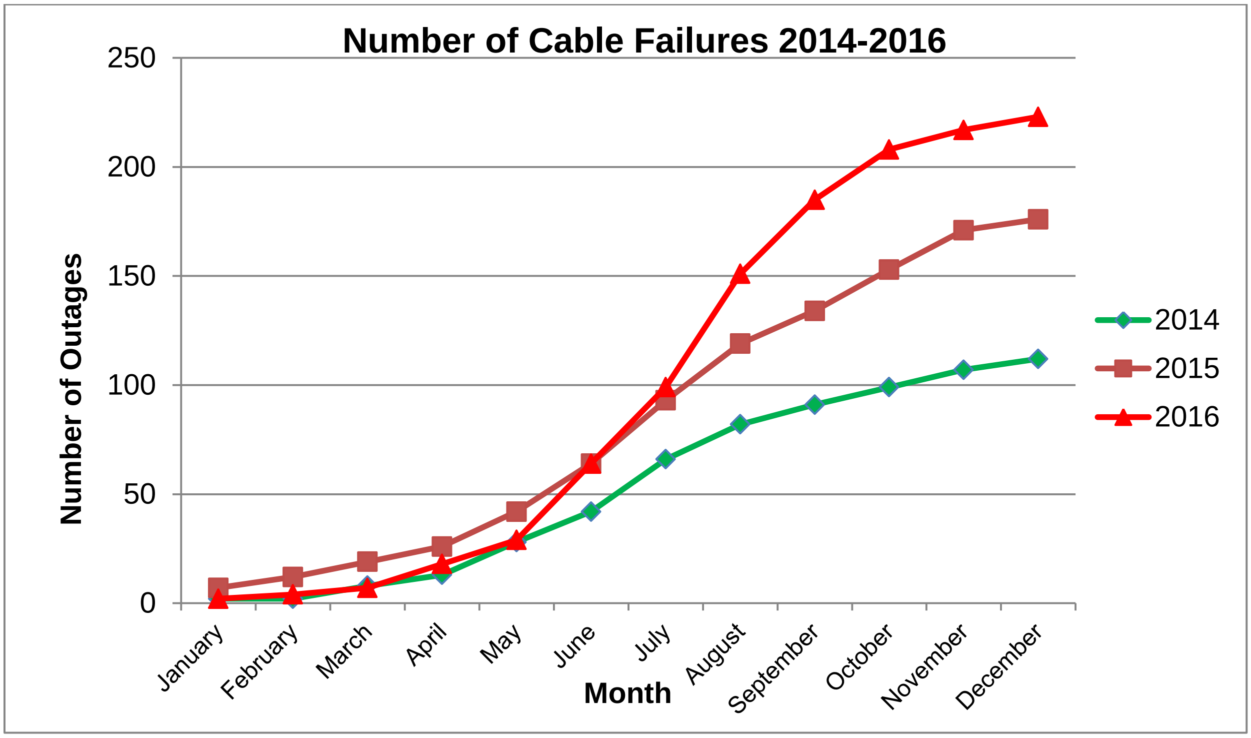
Figure 1 - Asset Health Index (HI) Summary for 2015



In order to ensure the reliable and safe operation of the distribution system, Alectra Utilities plans to renew a portion of Enersource RZ's distribution assets annually and has increased renewal investments in the DSP with respect to sub-standard underground cables and distribution poles.

The Enersource RZ has experienced an increasing number of underground cable failures as illustrated in Figure 3. In 2016, 223 feeder cable failures resulted in 4.98 million customer outage minutes ("COM"), which accounted for 50% of the total system COM; and such failures accounted for 84% of all outages caused by defective equipment in the Enersource RZ. A large number of double cable faults (involving both the original and backup loop feeders) occurred in 2016, leading to longer restoration times in the absence of an alternate supply source.

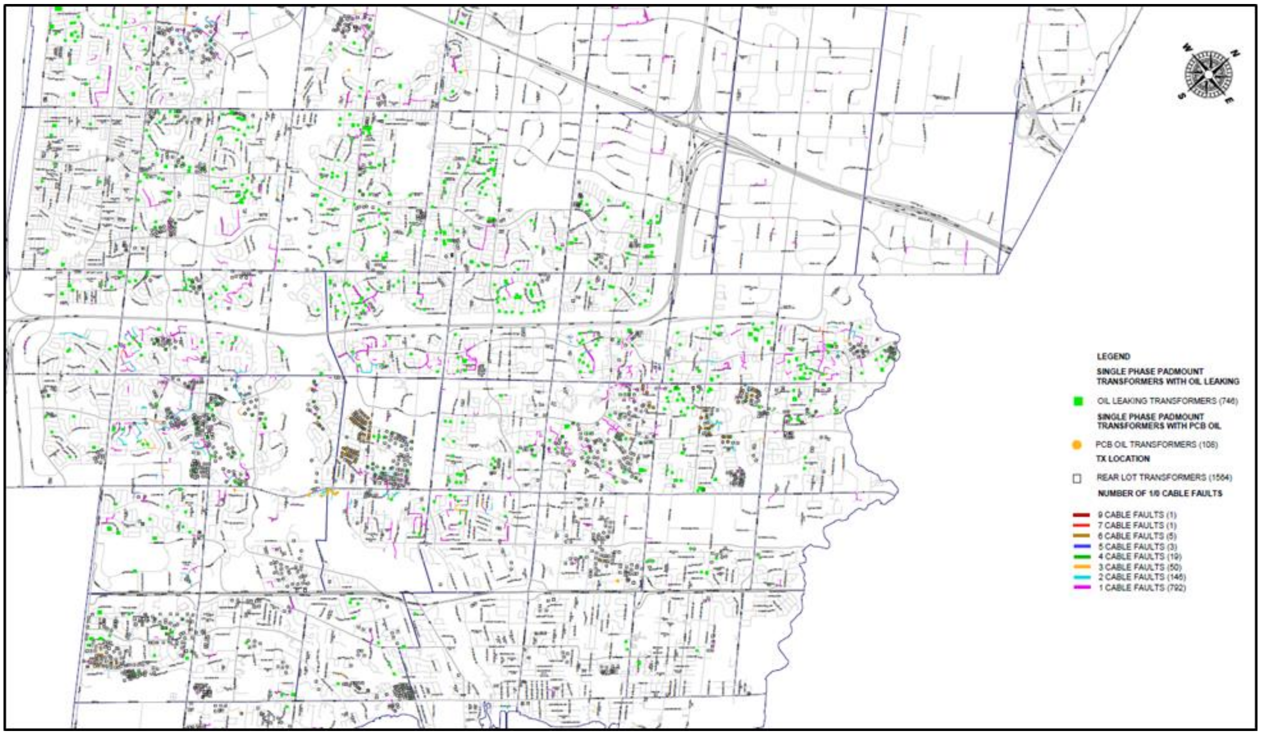
Figure 2 - Number of Experienced Cable Failures 2014 to 2016



In order to address the increasing trend of underground cable failures, Alectra Utilities uses an overlay methodology to identify and target the worst performing areas of the system (i.e. with multiple historical failures, cable types that are prone to failure, and potential need to concurrently renew other assets). The strategy is to pursue system renewal on an area-wide basis where warranted, thereby leveraging economies of scale and minimizing customer disruption and outages. Figure 4 illustrates the overlay methodology applied for underground system infrastructure.

The subdivision renewal investment plan set out in the Enersource RZ DSP reflects annual investments that have been paced to increase from $13.8MM in 2017 to $ 18.5MM in 2022.

Figure 3 - Overlay Map of Enersource's Underground Distribution Infrastructure

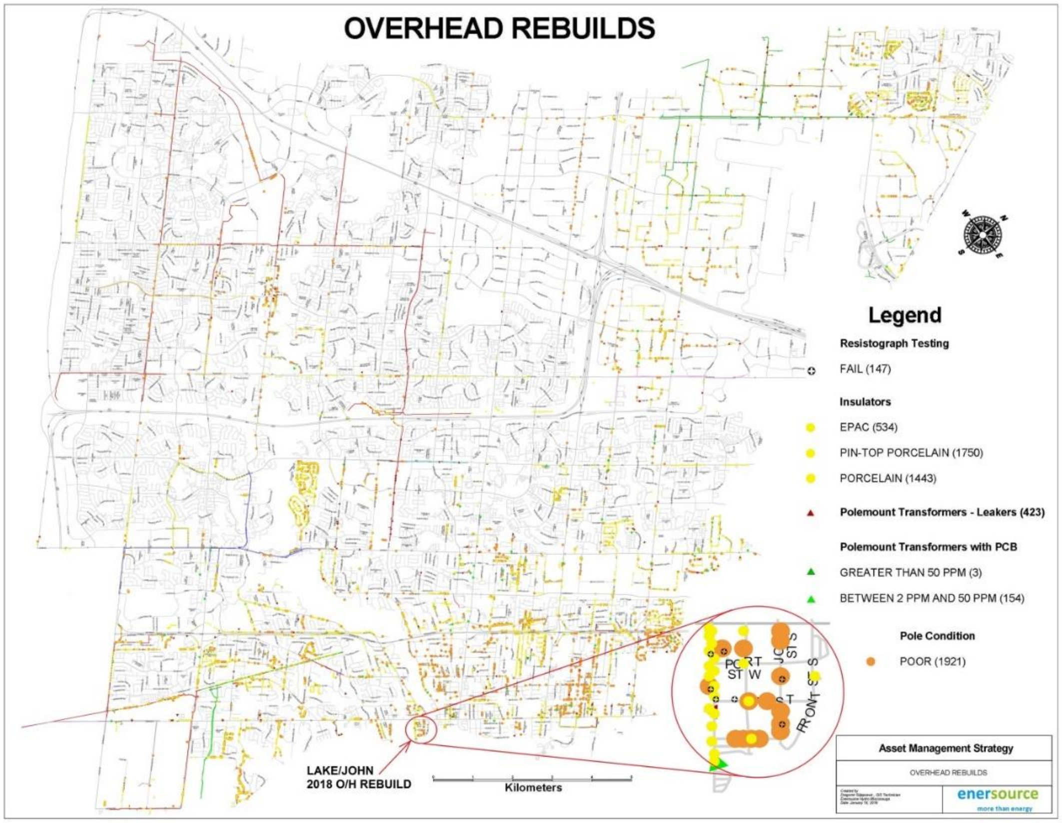


The Enersource RZ increased the frequency and rigor of overhead distribution asset inspections. The entire overhead distribution system was inspected in 2014 and 2015. Data from the inspection program improved the granularity of information and was utilized in the 2016 Kinectrics HI calculations for overhead assets.

Similar to underground cable renewal, Alectra Utilities uses an overlay methodology for overhead renewal and prioritizes investments to target worst performing areas of the system. In addition to investment needs driven by pole conditions, configuration and criticality, the overlay methodology also considers other investment needs such as insulators with a high propensity of failure which is the leading cause of pole top fires. Figure 5 below illustrates the overlay methodology applied for overhead system infrastructure.

The overhead distribution renewal and sustainment investment in the Enersource RZ DSP reflects annual investments that have been paced to increase from \$5.3MM in 2017 to \$ 7.2MM in 2022.

Figure 4: Overlay Map of Enersource's Overhead Distribution Infrastructure



Investment Needs to Address Environmental Risks

In recent years, the Alectra Utilities has increased the frequency of inspections, enhanced the rigor of outage data review, and implemented additional analytical methods to guide the pacing of asset replacements in the Enersource RZ. Based on more detailed and comprehensive transformer condition data, the Enersource RZ identified a number of transformers exhibiting signs of oil leaks and/or containing PCB oil. Typically, distribution transformers are run to failure due to their minor impact on system performance. However, potential oil leaks introduce significant environmental and safety risks, leading to the implementation of a proactive replacement project to remove such transformers from service. This investment need is further driven by the requirement to remain compliant with federal and provincial regulations that govern the reporting and remediation of oil spills over 100 litres or involving 1 gram of PCB, and the associated financial liabilities.

Alectra Utilities is committed to meeting its regulatory obligations, and is well aware of the impact of oil spills on the environment, public health and safety, and the credibility and trust established with its customers.

The Enersource RZ currently has 25,329 transformers located throughout its distribution system, including public right-of-ways, rear lots of private properties, commercial lands near high traffic areas, as well as customer-owned vault locations. From 2013 to 2016, 2,052 transformers that were identified to be leaking oil or containing PCBs were replaced. Transformer oil leaks at 103 sites led to environmental remediation. Over the four year period, the Enersource RZ incurred approximately $5.6M in environmental remediation costs as well as $19.4M in capital expenditures for transformer replacement, which were not included in rates.

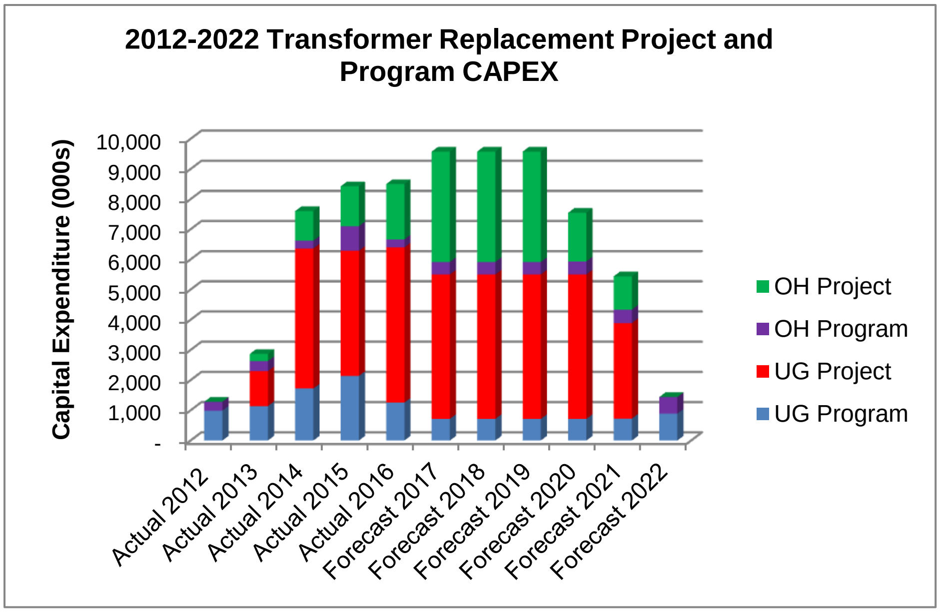
Alectra Utilities has developed a project to address the remaining backlog of 2,244 transformers requiring timely replacements. Table 130 outlines the remaining transformer types to be replaced as of December 31, 2016.

Table 130: List of Remaining Transformers to Replace (as of Dec. 31, 2016) – Enersource RZ

Transformer Type	PCB Transformers (Signs of Leaking)	PCB Transformers (Non-Leaking)	Non-PCB Transformers (Signs of Leaking)	Total
Single-Phase Pad Mount	3	95	733	831
Three-Phase Pad Mount	2	6	71	79
Vault Transformers	15	38	717	770
Pole Mount Transformers	0	31	533	564
Total	**20**	**170**	**2,054**	**2,244**

It is imperative that transformers showing signs of oil leaks are replaced before significant environmental impact occurs, so as to avoid costly remediation and significant disruptions to customers and the general public. At the same time, the Enersource RZ DSP reflects the ongoing implementation of the existing transformer replacement program, which addresses rusted or damaged transformers on a reactive basis. Figure 6 illustrates historical and forecast transformer replacement project capital expenditures relative to the reactive transformer replacement program.

Figure 5 - 2012-2022 Transformer Replacement Project and Program CAPEX



The forecast expenditures associated with the transformer replacement project (i.e. to address units showing signs of leaks) is forecast to cost \$8.4MM in each of 2017, 2018 and 2019, \$6.4MM in 2020 and \$4.3MM in 2021. The multi-year replacement project is scheduled to be completed in 2021.

The reactive replacement program to address substandard or failed transformers is forecast to cost \$1.1MM in each year from 2017 to 2019 and \$1.4MM in 2022.

Historical & Forecast Spending by Investment Category

Alectra Utilities provides a summary of its historical and proposed capital investments by category in Table 131 below. The proposed capital investments outlined in the Enersource RZ DSP 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 49, details by project for the proposed 2018 capital spending plan. For additional details, please refer to Section 3 of the Enersource RZ DSP, included as Attachment 50**.**

Table 131: Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
System Access	$10,245	$6,690	$5,626	$12,253	$11,822	$8,114	$11,679	$13,797	$13,812	$12,752	$10,812
System Renewal	$16,224	$20,854	$31,244	$37,472	$35,196	$37,386	$40,910	$42,150	$41,520	$40,160	$36,940
System Service	$9,860	$8,167	$10,951	$16,297	$12,724	$11,147	$13,422	$13,407	$13,717	$13,522	$14,007
General Plant	$29,220	$6,831	$6,230	$9,546	$4,333	$6,798	$6,672	$7,580	$8,411	$6,753	$5,869
Total	$65,550	$42,541	$54,051	$116,047	$64,075	$63,445	$72,683	$76,933	$77,459	$73,186	$67,627

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 the table below, followed by further discussions of the key projects for the DSP planning period.

Table 132: System Access Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
Road Projects	$1,213	$530	$205	$8	$414	$912	$3,120	$2,400	$2,640	$2,400	$1,440
Light Rail Transit	-	-	-	-	$75	$400	$2,900	$5,800	$5,550	$4,800	$3,500
New Subdivisions	$1,696	$1,135	$722	$4,225	$4,721	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Industrial & Commercial Services	$1,834	$2,141	$2,017	$3,234	$2,663	$1,300	$1,300	$1,300	$1,300	$1,300	$1,300
Residential Service Upgrades	-	-	-	$361	$517	$409	$409	$409	$409	$409	$409
Smart Metering Large Commercial	-	-	$414	$881	$764	-	-	-	-	-	-
Wholesale Metering	$2,247	$34	$52	$210	$636	$1,135	$45	$35	$65	$10	$280
Metering Equipment (excl. Spares)	$550	$1,979	$1,411	$1,410	$1,302	$1,427	$1,384	$1,337	$1,337	$1,337	$1,437
Metering Equipment - Spares	-	-	-	-	$131	-	-	-	-	-	-
Metering Equipment	$550	$1,979	$1,411	$1,410	$1,433	$1,427	$1,384	$1,337	$1,337	$1,337	$1,437
Smart Metering	$1,793	($209)	-	-	-	-	-	-	-	-	-
Smart Metering in New Condos	$773	$971	$719	$1,687	$436	$1,407	$1,426	$1,446	$1,446	$1,446	$1,446
Smart Metering	$2,565	$762	$719	$1,687	$436	$1,407	$1,426	$1,446	$1,446	$1,446	$1,446
Green Energy - FIT/MicroFIT	$140	$109	$87	$238	$162	$125	$95	$70	$65	$50	-
System Access	**$10,245**	**$6,690**	**$5,626**	**$12,253**	**$11,822**	**$8,114**	**$11,679**	**$13,797**	**$13,812**	**$12,752**	**$10,812**

Road Projects

The Enersource RZ's distribution assets are relocated and/or modified from time to time to accommodate road relocation and reconstruction projects initiated by road authorities (i.e. the City of Mississauga, Region of Peel, MTO). The timing and need for these projects are outside of Alectra Utilities control. As a result, capital expenditures within this category are subject to change, as can be seen in the fluctuations in historical spend. Pursuant to the *Public Service Works on Highways Act*, Alectra Utilities is obligated to relocate its assets to accommodate such projects and is able to recover a portion, but not all, of the resulting costs from the relevant road authorities in accordance with applicable cost sharing arrangements.

Light Rail Transit (LRT)

LRT is a major provincial initiative that will require substantial capital expenditure over the DSP period. The proposed Hurontario LRT will bring 20 km of rapid transit to serve the Cities of Mississauga and Brampton, connecting Mississauga's Port Credit Go Station to Brampton's Gateway Terminal. This project will require Alectra Utilities to relocate a significant number of overhead distribution system assets.

New Subdivisions, Industrial & Commercial Service and Residential Services Upgrades

Capital expenditures arising from new subdivisions, as well as from industrial, commercial and residential service upgrades, are driven by distribution load connection requests within the Enersource RZ. Although Alectra Utilities works closely with customers and developers to determine their needs, the need and timing for these projects are outside of Alectra Utilities' control. It is expected that capital expenditure on these initiatives will be steady and flat over the DSP period, in line with historical expenditures.

Metering Equipment and Smart Metering in New Condos

Capital expenditures for metering equipment and smart metering in new condominiums is forecast to be flat and steady over the DSP period, in line with historical expenditures. Given the uncertainty around the timing of metering installations for new condominiums, Alectra Utilities has kept the planned metering installations forecast for the Enersource RZ flat relative to 2017 forecast spend.

Green Energy – FIT/MicroFIT

Capital expenditures for connecting FIT and MicroFIT projects are expected to steadily decrease over the DSP period, given the government's initiative of phasing out the FIT program and future REG initiatives being captured under the net metering program.

<u>System Renewal</u>

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.

The table below presents the historical capital expenditures for system renewal investments for the Enersource RZ. Other than the subdivision renewal projects and transformer replacement project (discussed below), the other renewal projects are expected to require steady funding over the DSP period that are generally in line with historical spending.

Table 133: System Renewal Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
Subdivision Renewal Program	$8,396	$11,276	$9,307	$13,626	$11,389	$13,802	$16,102	$17,252	$18,502	$18,502	$18,502
Overhead Distribution Renewal and Sustainment	$2,733	$3,083	$5,051	$8,099	$8,344	$5,268	$6,492	$7,032	$7,032	$7,032	$7,212
Subtransmission Renewal	-	-	-	$1	$2,170	$3,736	$3,736	$3,286	$3,436	$4,186	$4,786
Transformer Replacement - UG	$1,283	$2,866	$7,605	$6,285	$6,397	$5,500	$5,500	$5,500	$5,500	$3,890	$890
Transformer Replacement - OH	-	-	-	$2,141	$2,102	$4,078	$4,078	$4,078	$2,048	$1,548	$548
Transformer Replacement - Spares	-	-	$5,018	$3,736	$20	-	-	-	-	-	-
Transformer Replacement	$1,283	$2,866	$12,623	$12,162	$8,519	$9,578	$9,578	$9,578	$7,548	$5,438	$1,438
Underground Distribution Renewal and Sustainment	$3,522	$3,327	$3,848	$3,258	$4,464	$4,670	$4,670	$4,670	$4,670	$4,670	$4,670
Emergency Replacement Program	$290	$302	$416	$325	$310	$332	$332	$332	$332	$332	$332
System Renewal	**$16,224**	**$20,854**	**$31,244**	**$37,472**	**$35,196**	**$37,386**	**$40,910**	**$42,150**	**$41,520**	**$40,160**	**$36,940**

Subdivision Renewal Projects

Capital expenditures for the subdivision renewal projects are driven by deteriorating underground system assets, particularly underground cables. Most of the cables installed in

Mississauga before 1989 are either unjacketed or direct-buried, thereby with higher susceptibility to failure.

Furthermore, as determined through Alectra Utilities' internal analysis of all cable failures for the Enersource RZ, in the period of January 2014 to January 2016, over 95% of failed cables were direct buried and without a jacket. In contrast, all jacketed primary cables installed in Mississauga over the last 22 years have experienced only a 4.8% failure rate. The subdivision renewal investments set out in the DSP are intended to address the increasing failure rates, which adversely impact the Enersource RZ's system reliability.

Transformer Replacement

As discussed above, Alectra Utilities is replacing a large number of distribution transformers that show signs of oil leaks. From 2013 to date, Enersource RZ has incurred approximately $5.6 million in remediation costs and $19.4 million in capital expenditure to address the environmental and safety risks associated with such transformers.

<u>System Service</u>

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 134 below, followed by further discussions of the key projects over the DSP planning period.

Table 134: System Service Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
Municipal Substation Construction & Upgrades	4,671	3,707	5,850	9,229	7,843	6,152	7,402	7,552	7,702	7,752	7,962
Subtransmission Expansion	3,425	2,713	3,237	3,920	1,934	2,749	2,539	2,499	2,499	2,499	2,499
Automation / SCADA Replacement and Enhancement Program	1,765	1,747	1,863	3,148	2,947	2,247	3,482	3,357	3,517	3,272	3,547
System Service	**9,860**	**8,167**	**10,951**	**16,297**	**12,724**	**11,147**	**13,422**	**13,407**	**13,717**	**13,522**	**14,007**

Municipal Substation Construction & Upgrades

The capital expenditures for municipal substation construction and upgrades are driven by the need for the renewal of substation assets (i.e. power transformers, high voltage and low voltage switchgear) that have reached the end of their useful life, and to meet growth needs in specific areas of the City. In particular, large capital investment is required to meet the projected growth in the downtown core. Alectra Utilities will also upgrade several substations that currently operate with end-of-life equipment (including replacement where the equipment is obsolete).

Subtransmission Expansion

Subtransmission expansion capital expenditures allow Alectra Utilities to build additional circuits on its subtransmission system as required to meet growing load demands. The level of capital expenditure for this category is expected to be steady in support of ongoing efforts to meet load demand in growth areas.

Automation/SCADA Replacement and Enhancement Program

Alectra forecasts that capital expenditures for automation and SCADA replacement and enhancement will be steady as part of the larger smart grid initiative.

<u>General Plant</u>

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 135 below, followed by further discussions of the key investments over the DSP planning period.

Table 135: General Plant Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
Engineering & Asset Systems	838	660	659	802	716	345	345	315	365	315	315
Rolling Stock	1,793	1,718	926	2,489	1,582	2,427	2,520	2,796	3,101	2,428	1,887
Information Technology	1,481	680	493	1,026	313	341	572	269	580	150	607
JDE / ERP System	704	944	883	1,632	20	50	55	55	60	60	65
Meter to Cash	465	498	686	1,435	436	580	580	620	530	550	500
Grounds & Buildings	1,568	2,246	2,417	1,910	1,037	2,855	2,400	3,325	3,575	3,050	2,295
Acquisition of Administrative Building	22,214	-	-	-	-	-	-	-	-	-	-
Major Tools	156	84	167	252	230	200	200	200	200	200	200
General Plant	**29,220**	**6,831**	**6,230**	**9,546**	**4,333**	**6,798**	**6,672**	**7,580**	**8,411**	**6,753**	**5,869**

Compared to historical years, fleet expenditures are expected to increase over the DSP planning period due to two primary drivers. The first driver centers on the timing of the vehicle replacement cycle for heavy equipment, such as bucket trucks and radial boom derricks, pick-up trucks, and vans. Expected replacements of these vehicles are higher during the planning period as vehicles purchased prior to 2012 need to be replaced. The second driver relates to the formation of Alectra Utilities. With respect to the Enersource RZ, many vehicle purchases slated for 2015 and 2016 were delayed to 2017 and beyond in anticipation of the merger, allowing for prudent vehicle purchase decisions to be made as part of the combined entity.

For facilities, three major replacements for the planning period cause the forecast spend to be higher than historical years: (i) replacement of windows at the Derry facility in 2019; (ii) building generator replacement at the Mavis facility in 2020; and (iii) renovation of the South Tower at the Mavis facility in 2021.

The Enersource RZ's IT expenditures are expected to be lower in future years relative to historical years, since investments related to Engineering & Asset Systems, Information Technology, JDE/ERP System and Meter to Cash systems are being evaluated and addressed on the basis of the consolidated utility.

Customer Consultation

In order to identify and account for customer preferences and needs, Enersource proactively engaged its customers in a variety of ways, including previously conducted customer satisfaction surveys. These surveys revealed important information in terms of customer satisfaction levels relative to Ontario and national comparators. In addition, they helped the utility understand key changes and trends in customers' perceptions and concerns over time.

As indicated by the results of the 2014 survey (Attachment 52), Mississauga customers generally rated the quality of service they experienced comparably with or better than the national and provincial survey averages. At the same time, the cost of electricity was a focus area for a sizeable segment of Mississauga customers. In this regard, the need for reasonable rates, followed by system reliability improvements, was identified as the top customer priority.

As previously discussed, Alectra Utilities engaged Innovative to solicit feedback on its DSP, as well as proposed incremental capital funding for the Enersource RZ. The Innovative Report is filed as Attachment 51.

A multifaceted customer engagement program was designed by Innovative to collect feedback from rate classes across multiple rate zones, including the Enersource RZ. As discussed below, the program included a voluntary online feedback portal allowing customers an opportunity to provide feedback. The number of responses to the online portal was unprecedented. Innovative also undertook telephone surveys among Residential and General Service customers to ensure feedback from representative customer samples and an invitation-only online survey to canvass the views of Large Users (5MW+).

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, that 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 conducting customer engagement, Alectra Utilities determined the maximum eligible capital it could apply for in the Enersource RZ, based on its most recent 2018 capital forecast of $83,118,772, before incorporating customer preferences, and its materiality threshold of $43,494,353. The computation of the materiality threshold is discussed in further detail below. The difference between the 2018 capital forecast, before incorporating customer preferences, and the materiality threshold was $39,624,419 as identified in Table 136 below.

Table 136 – Eligible Incremental Capital for Customer Consultation – Enersource RZ

Eligible Incremental Capital	Capital Expenditures $
2018 Capital Forecast	$83,118,772
Less: Materiality Threshold	$43,494,353
Maximum Eligible Incremental Capital	**$39,624,419**

Alectra Utilities identified twelve discrete and material capital projects for presentation to customers which totalled approximately $28.6MM for the Enersource RZ. These projects are identified in Table 137 below and do not include projects related to General Plant for which Alectra Utilities is not seeking incremental capital funding.

Table 137 - Eligible Capital Projects for Customer Consultation – Enersource RZ

Project Description	Capital Expenditures $
Road Widening Project - QEW (Evans to Cawthra)	$1,294,220
System Access	**$1,294,220**
Overhead Rebuild - Lake/John	$927,370
Overhead Rebuild - Church	$1,020,107
Leaking Transformer Replacement Project	$8,447,243
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	$1,548,270
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	$1,961,142
Subdivision Rebuild - Tenth Line Main Feeder	$1,135,398
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	$1,032,180
Subdivision Rebuild - Glen Erin & Battleford	$2,064,360
Subdivision Rebuild - Walmart Cables	$1,548,270
System Renewal	**$19,684,339**
Substation Upgrade - York MS	$3,232,029
Substation Upgrade - Webb MS	$4,432,750
System Service	**$7,664,780**
Total Distribution Capital	**$28,643,339**

As identified in the Innovative Report, customers were presented with the 2018 bill impacts related to the implementation of the projects listed in Table 137 above. These are identified in Table 138 below. The calculation of the rate riders associated with the proposed ICM is provided in Attachment 45. Large Use customers were presented with individual bill impacts based on historical usage.

Table 138 – Bill Impacts for Incremental Capital Presented to Customers – Enersource RZ

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	GS<50kW (2000kWh)	GS>50kW
System Access	$1.3	$0.02	$0.05	$0.98
System Service	$19.7	$0.11	$0.31	$5.82
System Renewal	$7.6	$0.29	$0.81	$14.95
Total	$28.6	$0.42	$1.17	$21.76

Further, for system service and system renewal projects, customers were asked which capital investment approach they would prefer Alectra Utilities to take in 2018 for the Enersource RZ: (i) system reliability is maintained (correlates with bill impacts identified in Table 138 above); (ii) system reliability eventually declines, calculated at 50% of the bill impacts identified in Table 138 above; and (iii) system reliability significantly declines.

A total of 17,595 customers completed the on-line survey of which 2,500 were from the Enersource RZ: 2,438 residential customers and 62 GS<50 kW customers. A total of 904 customers from the Enersource RZ completed the telephone survey: 504 residential customers, 200 small business (GS<50 kW) customers and 200 mid-market (GS > 50kW) customers. The customer engagement research suggested that customers in the Enersource RZ expect Alectra Utilities to maintain a robust capital investment program that ensures a highly reliable and modern distribution system. A majority of customers support some level of spending on the ICM projects, although customers are generally frustrated with their electricity bills and any impact to rates.

Tables 139,140 and 141 below summarize the % of residential, GS<50 kW and GS>50 kW customers who support Alectra Utilities' request for incremental capital funding for the Enersource RZ, by investment category. Two scenarios are presented: (i) the % of customers who support the incremental funding request is based on the total # of respondents completing the survey and (ii) the % of customers who support the incremental funding request is based on the total # of respondents who felt they knew enough to answer the question *"Given the varying levels of reliability under each scenario below and the projected customer rate impact of each, please indicate which approach* [maintain reliability, reliability declines, reliability significantly declines] *you want Enersource to pursue in 2018?"*

Table 139 - % of Respondents Supporting Incremental Capital Funding for System Service Projects – Enersource RZ

System Service - Maintain (Municipal Substation Builds)	% Respondents incl "Don't Know"		% of Respondents excl "Don't Know"	
	On-Line Survey	Telephone Survey [1]	On-Line Survey	Telephone Survey [1]
Residential	67%	48%	73%	52%
Small Business	61%	52%	69%	58%
Mid-Market	n/a	52%	n/a	54%

1. Recoded

Table 140 - % of Respondents Supporting Incremental Capital Funding for System Renewal Projects (Underground & Overhead) – Enersource RZ

System Renewal - Maintain (Underground Cables & Overhead Pole Lines)	% Respondents incl		% of Respondents	
	On-Line Survey	Telephone Survey [1]	On-Line Survey	Telephone Survey [1]
Residential	62%	47%	69%	51%
Small Business	52%	49%	60%	54%
Mid-Market	n/a	44%	n/a	46%

1. Recoded

Table 141 - % of Respondents Supporting Incremental Capital Funding for System Renewal Projects (Leaking Transformers) – Enersource RZ

System Renewal - Maintain (Leaking Transformer Replacement Project)	% Respondents incl		% of Respondents	
	On-Line Survey	Telephone Survey [1]	On-Line Survey	Telephone Survey [1]
Residential	64%	51%	75%	61%
Small Business	50%	52%	61%	65%
Mid-Market	n/a	50%	n/a	56%

1. Recoded

Based on its feedback from customers, Alectra Utilities revised its 2018 capital forecast from \$83,118,772 to \$77,233,772; and its ICM request from \$28,643,339 to \$24,247,022. No revision was made to the 2018 forecast or incremental capital funding request for System Access or System Renewal projects.

The System Service forecast and incremental capital funding request for 2018 was reduced by $4,432,750, which represents the removal of the Webb Municipal station construction.

The reduction corresponds to changes made to the Enersource RZ DSP. In the DSP Alectra Utilities has deferred certain expansion-related System Service projects (including the construction of Webb MS, Mini-Britannia MS, and Duke MS), as well as paced investments relating to Light Rail Transit construction beginning in 2018. In support of these adjustments, an increased focus will be placed on CDM initiatives and opportunities in certain areas of the City of Mississauga, particularly in the Downtown Core, so as to offset expected load growth in the near term.

By proposing to reduce the Enersource RZ's ICM request for 2018, continuing with System Renewal initiatives to ensure reliability, and leveraging CDM opportunities to a greater extent, Alectra Utilities believes that the adjustments it has made appropriately incorporate customer priorities and preferences (i.e., delivery of reliable services at reasonable rates; helping customers better manage consumption; and an overall lower support for System Service compared to System Renewal investments).

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 45.

Materiality

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:

$$\textit{Threshold Value}\ (\%) = 1 + [(\frac{RB}{d}) \times (g + PCI \times (1 + g))]) \times ((1 + g) \times (1 + PCI))^{n-1} + 10\%$$

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 1.60% and a growth rate of 0.21%.

The PCI of 1.60% is a placeholder to be updated with the OEB's approved PCI for 2018 when it is available. It is based on inflation of 1.90% less a productivity factor of 0.00% and a stretch factor of 0.30% as identified in Table 142 below.

The growth rate of 0.21% has been calculated in accordance with the ACM Report and is equal to the increase in revenue based on Enersource's 2013 OEB approved billing determinants divided by Enersource's 2016 actual billing determinants, using 2016 approved rates. The growth rate calculation is identified in Table 142 below.

Table 142 below summarizes the calculation of the threshold capital expenditure amount using the Board’s formula approved in the ACM Report. The threshold value for 2018 is 1.51% which results in a threshold capital expenditure value of $43,494,353.

Table 142– Threshold Capital Expenditure Calculation – Enersource RZ

Description	Amount
Inflation	1.90%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	1.60%
2016 Volumes @ 2016 Rates	$124,856,790
2013 Volumes @ 2016 Rates	$124,072,183
Growth Factor	0.21%
Year	2018
# Years since rebasing	5
Price Cap Index	1.60%
Growth Factor	0.21%
Dead Band	10%
Rate Base	$610,456,833
Depreciation	$28,721,695
Threshold Value % - 2018	151%
Threshold Capital Expenditure $ - 2018	**$43,494,353**

Eligible Capital Amount

Table 143 below compares the 2018 capital forecast for the Enersource RZ to the Threshold Capital Expenditure to calculate the maximum eligible incremental capital of $29,188,419 for the Enersource RZ.

Table 143 – Maximum Eligible Incremental Capital – Enersource RZ

Eligible Incremental Capital	Capital Expenditures $
2018 Capital Forecast	$83,118,772
Less: Materiality Threshold	$43,494,353
Maximum Eligible Incremental Capital	**$39,624,419**

Table 144 below identifies the eligible capital projects for which the Enersource RZ is seeking approval. Only projects that are discrete and material have been included. These projects are discussed in detail in Attachment 47.

Table 144 – 2018 Eligible Capital Projects by Category – Enersource RZ

Project Description	Capital Expenditures $
Road Widening Project - QEW (Evans to Cawthra)	$1,294,220
System Access	**$1,294,220**
Overhead Rebuild - Lake/John	$927,370
Overhead Rebuild - Church	$1,020,107
Leaking Transformer Replacement Project	$8,447,243
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	$1,548,270
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	$1,961,142
Subdivision Rebuild - Tenth Line Main Feeder	$1,135,398
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	$1,032,180
Subdivision Rebuild - Glen Erin & Battleford	$2,064,360
Subdivision Rebuild - Walmart Cables	$1,548,270
System Renewal	**$19,684,339**
Substation Upgrade - York MS	$3,268,463
System Service	**$3,268,463**
Total Distribution Capital	**$24,247,022**

<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.

The 2016 ROE for the Enersource RZ was calculated to be 6.13%, 280 basis points below its approved 2016 ROE of 8.93%. Therefore, Alectra Utilities satisfies the Means Test for the Enersource RZ. The ROE calculation for 2016 for the Enersource RZ, included in RRR 2.1.5.6, is filed as Attachment 46. Achieved ROE for each of the four predecessor utilities forming Alectra Utilities was within 300 basis points of deemed ROE for 2016.

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. 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 2018.

Enersource's approved 2013 distribution revenue requirement from its last Cost of Service Application (EB-2013-0033) is $117,989,982. The materiality threshold, defined by the OEB as 0.5% of distribution revenue requirement is $589,950. Each of the eligible projects identified in the business case summaries exceed the materiality threshold. Further, they are new projects for which capital funding has not previously been approved in Enersource's last Cost of Service Application (EB-2013-0033).

Further information with respect to the driver of each project is provided in each business case in Attachment 47.

Prudence

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 47.

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 47.

Project/ Budget/ In-Service Date ("ISD")	**Project Need and Description**
QEW – Evans to Cawthra Roads Project (see System Access Project Business Case 2018-C0531-1) Budget: $1.29MM Forecast ISD: Q4/2018	**<u>QEW – Evans to Cawthra Roads Project</u>** **<u>System Access: $1.29MM</u>** <u>Project Description and Drivers</u> • As a result of the Ministry of Transportation's ("MTO") redesign of the on and off ramps at Dixie Road and QEW, Alectra Utilities is required by legislation to relocate electrical infrastructure to accommodate the road work, as well as the final 'cloverleaf' ramp configuration (i.e., provision of off and on ramps in both directions) planned for the area. • Timelines for the execution of the road works are driven by the Region of Peel, City of Mississauga, and the MTO. Alectra Utilities monitors the status of project planning and scheduling through active communications with these stakeholders. <u>Project Options</u> • This mandatory project involves the removal of 39 poles, relocation of 72 poles, and installation of 3 temporary poles. It also includes the implementation of an underground crossing of the QEW. The MTO will contribute all costs related to the relocation of assets on municipal property, and share costs on a 50/50 basis for asset relocations on MTO lands. • The project is the preferred solution as compared to the other option

	assessed (i.e., installation of underground feeder cables instead of an overhead system). The underground solution was determined to be uneconomical with an estimated cost between \$9.7M and \$16M. The investment required for the selected solution is \$1.294M (i.e. total costs of \$1.618M less capital contributions of \$0.324M). Without this investment, the execution of the planned road works would be impeded.
Glen Erin & Montevideo Subdivision Rebuild (see System Renewal Project Business Case 2018-C0505-1) Budget: \$1.96MM Forecast ISD: Q4/2018	**<u>Glen Erin & Montevideo Subdivision Rebuild</u>** **<u>System Renewal: \$1.96MM</u>** <u>Project Description and Drivers</u> • Alectra Utilities' distribution system is 65% underground and 35% overhead. Underground cables have been identified in the Kinectrics' ACA as the asset class with the highest percentage of poor and very poor condition assets. Increasing failures on early generation underground cables (which are mostly unjacketed (i.e., without a protective sheath) and/or direct buried) are leading to rising numbers of outages and having an adverse impact on reliability. This project addresses the underground cables that are in poor condition in the Glen Erin and Montevideo area, which Alectra Utilities identified as having experienced a high number of underground system failures. Since 2005, 16 underground cable failures have occurred in the Glen Erin and Montevideo area, affecting 3,064 customers for a total of 308,531 outage minutes. Since 2013, SAIDI and SAIFI for this area have been 4 times and 2 times greater than the three year system average, respectively. Customers in this area have experienced 2 outages every year for the last three years due to these specific assets, alone. The cables and transformers in the area are approximately 40 years old and are beyond the end of useful life. <u>Project Options</u> • The project involves the renewal and replacement of the early generation underground distribution cables and 8 padmount transformers in the Glen Erin and Montevideo area. A complete rebuild provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration would allow Alectra Utilities to reduce replacement cost by \$1.5M (i.e. by replacing the existing 6km system with 4.5km of new infrastructure). Moreover, the new cables will be installed in PVC ducts to make future replacement much less costly and to meet current standards for residential underground distribution. • As the proposed solution, the project is preferable to the other options assessed (i.e., to defer investment and operate with existing assets; or to rehabilitate cables using injection technology). First, without the required

	investment, the continuation of reactive measures would not address the escalating trend of deteriorating asset condition and increasing outages in this area. As these cables continue to fail, they will reach a point where repair is no longer an option. Continuing to operate the existing cables is most likely to result in failures of both the primary and back-up cables, thereby leaving field crews with only one option – i.e. to open trench a new pit for cable installation. This would significantly increase restoration time and cost. Second, Alectra Utilities has determined that this area is not suitable for cable injection since the cables at issue contain solid-type conductors which cannot be injected.
Glen Erin & Battleford Subdivision Rebuild (see System Renewal Project Business Case 2018-C0505-5) Budget: $2.06MM Forecast ISD: Q4/2018	**<u>Glen Erin & Battleford Subdivision Rebuild</u>** **<u>System Renewal: $2.06MM</u>** <u>Project Description and Drivers</u> • Mississauga's distribution system is 65% underground and 35% overhead. Underground cables have been identified by Kinectrics' ACA as the asset class with the highest percentage of poor and very poor condition assets. Increasing failures on early generation underground cables (which are mostly unjacketed and/or direct buried) are leading to increasing outages and adversely impacting reliability. This project addresses the poor condition of underground cables in the Glen Erin and Battleford area, which was identified by Alectra as having experienced a high number of underground system failures. • Since 2005, 17 underground cable failures have occurred in the Glen Erin and Battleford area, affecting 32,572 customers for a total of 191,139 outage minutes. The cables and transformers in the area are approximately 40 years old and are beyond the end of useful life. As per the 2016 ACA results, the cables in this area were flagged to be in very poor condition and are in need of immediate replacement. <u>Project Options</u> • The project involves renewing and replacing the early generation underground distribution cables and 5 padmount transformers in the Glen Erin and Battleford area to update them to present day standards. A complete rebuild provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration allows for minimized replacement cost (i.e., by replacing the existing 11.5km system with 6.5km of new infrastructure). • As the proposed solution, the project is preferable to the other options

	assessed (i.e. to defer investment and operate with existing assets; or to rehabilitate cables using injection technology). First, without the required investment, the continuation of reactive measures would not address the escalating trend of deteriorating asset condition and increasing outages in this area. As these cables continue to fail, they will reach a point where repair is no longer an option. Continuing to operate the existing cables is most likely to result in failures of both the primary and back-up cables, thereby leaving field crews with only one option – i.e., to open trench a new pit for cable installation. This would significantly increase restoration time and cost. Second, Alectra Utilities has determined that this area is not suitable for cable injection since the cables at issue contain solid-type conductors which cannot be injected.
Credit Woodlands & Wiltshire Subdivision Rebuild (see System Renewal Project Business Case 2018-C0505-2) Budget: $1.55MM Forecast ISD: Q4/2018	**<u>Credit Woodlands & Wiltshire Subdivision Rebuild</u>** **<u>System Renewal: $1.55MM</u>** <u>Project Description and Drivers</u> • Through inspections between 2013 and 2016, a large number of distribution transformers in the Enersource RZ were found to exhibit signs of oil leaks or contain PCBs, which could give rise to significant liabilities, in the event of spills. Eleven such transformers have been identified in the Credit Woodlands and Wiltshire area. While distribution transformers are normally operated on a run to failure basis, these 11 units (including 6 that are showing signs of leaking) need to be replaced to address safety, environmental, reliability, financial and regulatory risks. • There have been 6 underground cable failures in this area, affecting 814 customers for a total of 22,531 outage minutes. SAIDI for this area has been increasing for the past several years and was 45% and 99% higher than the system average in 2015 and 2016, respectively. The cables and transformers in the area are approximately 37 years old and as per the 2016 ACA results, this cable section was flagged to be in very poor condition and requires immediate replacement. <u>Project Options</u> • The project involves renewing the distribution system in this area by replacing cables that are beyond the end of their useful life and transformers (11 in total) showing signs of leaks or containing PCB. A complete rebuild provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration would allow Alectra Utilities to reduce replacement cost by $0.5M (i.e. by replacing the existing 6.5km of underground cables

	with 5km of new infrastructure). New cables will be installed in PVC ducts to make future replacements less costly and meet current standards for residential underground distribution. • As the proposed solution, the project is preferable to the other options assessed (i.e., to defer investment and operate with existing assets; or to rehabilitate cables using injection technology and replace only the transformers). First, without the required investment, the continuation of reactive measures would not address the escalating trend of deteriorating asset condition and increasing outages in this area. As these cables continue to fail, they will reach a point where repair is no longer an option. Continuing to operate the existing cables is most likely to result in failures of both the primary and back-up cables, thereby leaving field crews with only one option – i.e., to open trench a new pit for cable installation. This would significantly increase restoration time and cost. Second, Alectra Utilities has determined that this area is not suitable for cable injection based on two key factors, the first being that the cable most likely cannot be injected (i.e., given the large portion of solid type conductor), and the second being that injection of these specific cables may not be feasible due to the high number of cable splices (which makes injection uneconomical) as well as the presence of corroded neutrals (which leads to the risk of distribution system protection mis-operation and prolonged outages, and cannot be resolved by injection). Finally, replacing the transformers would help address environmental risks.
Tenth Line Main Feeder Subdivision Renewal (see System Renewal Project Business Case 2018-C0505-3) Budget: $1.14MM Forecast ISD: Q4/2018	**<u>Tenth Line Main Feeder Subdivision Renewal</u>** **<u>System Renewal: $1.14MM</u>** <u>Project Description and Drivers</u> • Alectra Utilities distribution system in Mississauga is 65% underground and 35% overhead. Underground cables have been identified by Kinectrics' ACA as the asset class with the highest percentage of poor and very poor condition assets. Increasing failures on early generation underground cables (which are mostly unjacketed and/or direct buried) are leading to increasing outages and adversely impacting reliability. This project addresses the poor condition of underground cables in the Tenth Line area, which was identified as having experienced a high number of underground system failures. • According to the ACA, main feeder cables in the Tenth Line area are in very poor condition and require immediate replacement. Two particular sections of direct buried cables have each failed 4 times, impacting a total of 7,074 customers (334,797 outage minutes) and 3,684 customers (177,215 outage minutes), respectively. In addition, portions of these cables are located in rear lots, making ongoing repairs particularly difficult. Repairs of these direct

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buried cables in rear lot locations would also cause significant disruptions to residents and the risk of damage to customer properties in the process.

<u>Project Options</u>

• The project involves renewing and replacing the early generation underground feeder cables in the Tenth Line area. A complete rebuild provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration allows for minimized replacement cost (i.e. by replacing the existing 14km of underground cables with 7km of new infrastructure, and by abandoning the switchgear that has reached end of life). The new cables will be installed in PVC ducts to make future replacements less costly and meet current standards for underground feeder cables.

• As the proposed solution, the project is preferable to the other options assessed (i.e., to defer investment and continue operating the existing cables; or to rehabilitate cables using injection technology). First, without the required investment, the continuation of reactive measures would not address the escalating trend of deteriorating asset condition and increasing outages in this area. As these cables continue to fail, they will reach a point where repair is no longer an option. Continuing to operate the existing cables is most likely to result in failures of both the primary and back-up cables, thereby leaving field crews with only one option – i.e. to open trench a new pit for cable installation. This would significantly increase restoration time and cost, as portions of the cable are in rear lots, which would entail disruption to residents during repairs, and further increase repair cost and restoration time. Second, Alectra Utilities has determined that this area is not suitable for cable injection based on cable service quality, condition and age.
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Folkway & Erin Mills Main Feeder Subdivision Rebuild

(see System Renewal Project Business Case 2018-C0505-4)

Budget:
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<u>Folkway & Erin Mills Main Feeder Subdivision Rebuild</u>

<u>System Renewal: $1.03 MM</u>

<u>Project Description and Drivers</u>

• Alectra Utilities' distribution system in Mississauga is 65% underground and 35% overhead. Underground cables have been identified in the Kinectrics' ACA as the asset class with the highest percentage of poor and very poor condition assets. Increasing failures on early generation underground cables (which are mostly unjacketed and/or direct buried) are leading to increasing outages and adversely impacting reliability. This project addresses the poor condition of underground cables in the Folkway and Erin Mills area, which was identified by Alectra Utilities as having experienced a high number of
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$1.03 MM Forecast ISD: Q4/2018	underground system failures. • According to the ACA, the main feeder cables in the Folkway and Erin Mills area are in very poor condition and require immediate replacement. One particular section of direct buried cable has failed 5 times, impacting a total of 6,220 customers (278,119 outage minutes). Portions of this cable are located in rear lots, making repairs particularly difficult. Repairs of these direct buried cables in rear lot locations would also result in significant disruptions to residents and raise the risk of damage to customer properties in the process. <u>Project Options</u> • The project involves renewing and replacing the early generation underground feeder cables in the Folkway and Erin Mills area. A complete rebuild provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration allows for minimized replacement cost. The new cables will be installed in PVC ducts, making future replacements easier and less costly. • As the proposed solution, the project is preferable to the other options assessed (i.e., to defer investment and continue operating the existing cables; or to rehabilitate cables using injection technology). First, without the required investment, the continuation of reactive measures would not address the escalating trend of deteriorating asset condition and increasing outages in this area. As these cables continue to fail, they will reach a point where repair is no longer an option. Continuing to operate the existing cables is most likely to result in failures of both the primary and back-up cables, thereby leaving field crews with only one option – i.e., to open trench a new pit for cable installation. This would significantly increase the restoration time and cost. Portions of the cable are in rear lots, which would require disruption to residents during repairs and further increase repair costs and restoration time. Second, Alectra Utilities has determined that this area is not suitable for cable injection based on cable service quality, condition and age.
City Centre Drive Rebuild (see System Renewal Project Business Case 2018-C0505-6) Budget:	**<u>City Centre Drive Rebuild</u>** **<u>System Renewal: $1.55MM</u>** <u>Project Description and Drivers</u> • While a large proportion of underground cables installed in Mississauga before 1989 were either unjacketed and/or direct buried, portions of the system servicing large customers were installed in duct with utility chambers. Through inspections, Alectra Utilities identified problems with this infrastructure. Specifically, there are rusted lids, spalling of the concrete,

\$1.55MM Forecast ISD: Q4/2018	access restrictions, and separation of the foundation. These issues are considered to identify poor performing areas in the Enersource RZ, which led to the identification of an investment need to renew the underground system in the City Centre Drive area. • There are two subgrade utility chambers in the City Centre Drive area, through which 15 medium voltage feeder cables pass. Given their configuration and condition, these chambers present significant constraints in terms of physical access. Constructed in the 1970s, the design for these chambers incorporates an older style access hatch leading to a chimney, both of which are undersized, relative to current day standards. When responding to cable failures, workers accessing the chamber must enter through a very narrow entrance, and have to be tethered to a lanyard and a tripod-configured hoist for safety reasons. Even so, any required emergency rescue would be impeded by the restrictive configuration of the chamber, chimney and access way. It takes considerable time to perform the necessary switching operations to isolate the 15 cables so that the chamber can be made safer for workers before repairs are carried out. The design and protection used for these cables are outdated and substandard, thus complicating repairs and posing safety and operational risks. • The cables passing through the chambers in question supply one large user in the City Centre Drive area. Due to the congestion of cables in trays, several of the cables lay directly against each other. In the event of a cable fault, this leads to an increased risk of damage and failure to adjacent cables from the faulted cable. These cables are approximately 35 years old and are beyond the end of their useful life. Alectra Utilities has experienced failures on cables of a similar make and vintage in another area of the Enersource RZ. <u>Project Options</u> • The project involves replacing the existing cables and civil infrastructure in the City Centre Drive area, thereby mitigating the risk of a significant and prolonged outage. Through the project, Alectra Utilities will also be able to eliminate the safety hazards to field crews that arise from the current design of civil chambers. • As the proposed solution, the project is preferable to the other options assessed (i.e., to continue operating with the existing cables and civil chambers; or to rehabilitate the cables using injection technology). Leaving the situation as is means Alectra Utilities' workers would have to continue operating in substandard and hazardous conditions, when responding to

	cable outages in the area. Further, cable injection would not be cost effective (given that the existing cables are already in ducts), nor would it resolve the issue relating to substandard civil chambers. • Without this investment, cable failure in this area, which based on the condition of the cables is highly probable in the near future, would result in a significant and prolonged outage to a large customer. It would also result in Alectra Utilities' field crews being subjected to challenging chamber conditions.
Lake/John Area Overhead Rebuild (see System Renewal Project Business Case 2018-C0561-1) Budget: $0.93MM Forecast ISD: Q4/2018	**Lake/John Area Overhead Rebuild** **System Renewal: $0.93MM** Project Description and Drivers • Through its inspection program in the Enersource RZ, Alectra Utilities identified a number of poles that are in poor condition (i.e. signs of rotting, mechanical damage, insect infestation, and cracking). Based on these inspections, and resistograph testing of wood poles' residual strength, the area south of Lakeshore Road W. between John Rd and Mississauga Rd was identified as requiring renewal, 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 or containing PCB. • As a 1960s open bus secondary configuration, the overhead system in the area is not to current standard. Vandalism due to copper wire theft and outages caused by animal contacts are also known issues in the area. Project Options • The project involves renewing the overhead system in this area to bring it in line with present day standards, including the replacement of 50 poles in poor condition (with average age exceeding 40 years), 22 poles with problematic types of porcelain insulators, and 2 transformers showing signs of leaks or containing PCB, as well as the installation of copper clad ground wires to deter theft of ground wires and of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed. • As the proposed solution, the project is preferable to the other options assessed (e.g., to replace with an underground system; to defer overhead renewal and continue with reactive maintenance; or to replace only the assets in very poor condition), because it would most effectively address the project drivers identified above, while allowing system design to be right-sized on an area-wide basis and minimizing interruptions required to

	complete the work. • The underground solution would be uneconomical (estimated cost between \$5.4MM to \$9MM). Spot replacements of only those assets posing imminent hazards would require piecemeal work with high mobilization costs, prohibit upgrades to present day standards, and increase long-term maintenance, inspection and replacement costs. • Without the required investment: the distribution system in this area would continue to be exposed to risks of pole fires due to porcelain insulators; there will be worker and public safety concerns due to missing ground wiring and poles in poor conditions; and potential environmental contamination risks exist due to transformer oil leaks.
Church St. Area Overhead Rebuild (see System Renewal Project Business Case 2018-C0561-2) Budget: \$1.02MM Forecast ISD: Q4/2018	**<u>Church St. Area Overhead Rebuild</u>** **<u>System Renewal: \$1.02MM</u>** <u>Project Description and Drivers</u> • Through the inspection program, Alectra Utilities identified a number of poles as being in poor condition (i.e. signs of rotting, mechanical damage, insect infestation, and cracking). Based on these inspections, and resistograph testing of wood poles' residual strength, the Streetsville area east of Queen St. along Church St. was found to require renewal. This is due to the poor condition 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 or containing PCB, • As a 1980s open bus secondary configuration, the overhead system in the area substandard. Vandalism due to copper wire theft, outages caused by animal contacts, and inaccessibility of certain overhead assets to field inspectors (due to nearby structures) are also known issues in the area. <u>Project Options</u> • The project involves renewing the overhead system in this area to present day standards, including through the replacement of 55 poles that are in poor condition (with an average age exceeding 40 years), 9 poles with problematic types of porcelain insulators, and 6 transformers that show signs of leaks or that contain PCB. The project will also involve the installation of copper clad alternative ground wires to deter theft, and the installation of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed. • As the proposed solution, the project is preferable to the other options

	assessed (e.g. to replace with an underground system; to defer overhead renewal and continue with reactive maintenance; or to replace only the assets in very poor condition), because it would most effectively address the identified project drivers, while allowing system design to be right-sized on an area-wide basis and minimizing interruptions required to complete the work. • The underground solution would be uneconomical (estimated cost between \$6M to \$10M). Spot replacements of only those assets posing imminent hazards would require piecemeal work with high mobilization costs, prohibit upgrades to present day standards, and increase long-term maintenance, inspection and replacement costs. • Without the required investment, the distribution system in this area would continue to be exposed to risks of pole fires due to porcelain insulators; worker and public safety concerns due to missing ground wiring and poles in poor conditions will continue, and the risk of potential environmental contamination due to transformer oil leaks will also persist.
Transformer Replacement Project (see System Renewal Project Business Case 2018-C0563-2) Budget: \$8.45MM (2018) \$36.0MM total (2017 to 2021) Forecast ISD: Q4/2018 for 2018 scope, 2021 for the project.	**Transformer Replacement Project** **System Renewal: \$8.45MM** Project Description and Drivers • There are over 25,300 distribution transformers in Mississauga. Through rigorous inspections in 2013 to 2016, a large number of transformers were found to exhibit signs of oil leaks or contain PCB, which could lead to significant liabilities, in the event of spills. • While distribution transformers are normally operated on a run to failure basis, the need to minimize safety, environmental, reliability, financial and regulatory risks has led to the replacement of 2,052 such transformers from 2013 to 2016. Transformer oil leaks at 103 sites led to \$5.6MM in incurred costs for environmental remediation and \$19.4MM in capital expenditures for transformer replacements from 2013 to 2016, which were not included in rates. • As of January 1, 2017, a total of 2,244 in-service transformers need to be replaced (as identified based on inspections undertaken from 2013 to 2016) as part of the Enersource RZ's multi-year transformer replacement project. This total includes the 1,629 units flagged in the Kinectrics ACA as being in poor or very poor condition based on year end 2015 data, as well as additional transformers identified through inspections in 2016. Other problematic transformers requiring replacement (i.e. rusted or damaged units) that are beyond the scope of this project would be addressed on a reactive basis as part of the Alectra Utilities' ongoing transformer

replacement program in the Enersource RZ.

- A breakdown of transformers to be addressed through this multi-year 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	3	95	733	**831**
Three-Phase Pad Mount	2	6	71	**79**
Vault Transformers	15	38	717	**770**
Pole Mount Transformers	0	31	533	**564**
Total	**20**	**170**	**2,054**	**2,244**

Project Description

- Through the transformer replacement project, Alectra Utilities will replace 2,244 transformers that have been identified as showing signs of oils leaks or containing PCB in a well-planned and paced manner until 2021. In connection with this project, Alectra Utilities has leveraged opportunities to perform replacements during planned underground or overhead system renewal projects in order to minimize the number of site visits and outages required. This solution is distinct from the existing transformer replacement program, which addresses rusted or damaged units on a reactive and ongoing basis.
- As the proposed solution, the project is preferable to the other option assessed (i.e., to continue to run distribution transformers to failure), because it would more effectively address the safety, environmental, reliability, financial and regulatory risks identified above (particularly to avoid disruptive and costly environmental clean-up).
- Although continuing with only reactive replacement would result in lower capital expenditures in the near term, such an approach would not adequately address the significant risks associated with the transformers exhibiting signs of leaks or containing PCB, and would prove more costly in the long run (due to costs of eventual site remediation and ad-hoc

	replacements). It would also pose significant reputational risk. It is imperative that these risks be addressed proactively at an early stage, before major contamination and liabilities materialize.
York MS (see System Service Project Business Case 2018-C0504-1) Budget: $1.04 MM (2017), $2.23 MM (2018) Forecast ISD: Q4/2018	**York MS** **System Service: $3.27MM** Project Description and Drivers • This project is driven primarily by growth in demand in the Meadowvale Business Park Area and, secondarily, by the need to update equipment and the configuration at the station to bring these in line with current standards and improve reliability. • York MS supplies the Meadowvale Business Park Area, the second largest employment area in Mississauga. The area is forecasted to experience an increase in load of 20MVA over the next 5 years due to planned business and employment growth. Based on the current distribution system configuration, approximately 50% (or 10MVA) of this forecasted load increase will need to be supplied from York MS, which has a normal operating capacity of 20MVA and present demand of 14MVA. As such, load on the station will in the near term exceed the station's normal operating capacity. In addition, York MS provides back-up for Argentia MS, Winston MS, and Century MS. The project will increase the station's capacity to accommodate projected growth in the area and to provide additional contingency capacity for other stations. • York MS is one of just two outdoor 44kV/13.8kV substations remaining in Mississauga and was originally commissioned in 1998 as a temporary station. The existing equipment and configuration is outdated and aged, and experiences reliability issues associated with the cable egress, protection and station configuration. The station equipment (i.e., primary bushings, lighting arrestors) are also directly exposed to environmental elements. • Further, the station's substandard protection scheme (i.e., no high voltage switchgear; use of fuses; lack of differential protection) increases the risk of equipment failure and damage; and the lack of oil containment poses significant environmental concerns should transformer failures occur. Project Options • This project involves upgrading York MS to increase station capacity to meet the forecasted increase in demand and to improve the reliability associated with station equipment and configuration. More specifically, the project includes the installation of low voltage switchgear, high voltage switchgear,

	and a 20MVA power transformer. • As the proposed solution, the project is preferable to the other options assessed (i.e., to defer all station upgrades; or to upgrade configuration while deferring capacity increase), as it would most effectively address each of the pressing requirements relating to capacity demands, reliability issues, and environmental risks. Without this investment, the station would not be able to service forecast load growth in the area based on its current loading limits. Moreover, the station will continue to be exposed to an elevated risk of equipment failure and damage; further, the potential for environmental contamination risks exists, also.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $24,247,022 is $1,962,111. Table 145 below summarizes the incremental revenue requirement for the eligible projects.

Table 145 –Incremental Revenue Requirement – Enersource RZ

Incremental Revenue Requirement	Amount
Return on Rate base - Total	$1,539,083
Amortization	$589,204
Incremental Grossed Up PIL's	($166,176)
Total	**$1,962,111**

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-2013-0033) and is summarized in Table 146 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. Accordingly, 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 48), as follows:

Table 146 – Incremental Revenue Requirement by ICM Project – Enersource RZ

Project Description	Return on Rate base	Amortization	Incremental Grossed Up PIL's	Total Revenue Requirement
Road Widening Project - QEW (Evans to Cawthra)	$82,551	$25,295	($11,856)	$95,990
System Access				**$95,990**
Overhead Rebuild - Lake/John	$58,782	$23,816	($6,518)	$76,080
Overhead Rebuild - Church	$64,660	$26,198	($7,169)	$83,688
Transformer Replacement Project - Overhead	$534,990	$223,559	($57,076)	$701,483
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	$98,250	$38,032	($11,495)	$124,787
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	$124,450	$48,174	($14,561)	$158,063
Subdivision Rebuild - Tenth Line Main Feeder	$72,050	$27,890	($8,430)	$91,510
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	$65,500	$25,355	($7,664)	$83,191
Subdivision Rebuild - Glen Erin & Battleford	$131,000	$50,710	($15,327)	$166,383
Subdivision Rebuild - Walmart Cables	$98,250	$38,032	($11,495)	$124,789
System Renewal				**$1,609,974**
Substation Upgrade - York MS	$208,590	$62,142	($14,585)	$256,147
System Service				**$256,147**
Incremental Revenue Requirement				**$1,962,111**

Rate Riders

Alectra Utilities is seeking Board approval for the ICM rate riders, for the Enersource RZ identified in Table 147 to recover the revenue requirement of $1,962,111 identified in Table 146 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 45. 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 147 - Incremental Capital Funding Rate Riders – Enersource RZ

Rate Class	Service Charge Rate Rider	Volumetric Rate Rider	Per
Residential	$0.36	$0.0000	kWh
General Service under 50 kW	$0.65	$0.0002	kWh
General Service 50 to 499 kW	$1.15	$0.0692	kW
General Service 500 to 4999 kW	$26.20	$0.0356	kW
Large Use	$206.57	$0.0442	kW
Unmetered	$0.13	$0.0002	kWh
Street Lighting	$0.02	$0.1730	kW

Bill Impacts - ICM Rate Riders

Table 148 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 0.1% for the General Service 50 to 499 kW and Large Use classes to 0.6% for Street Lighting.

1 **Table 148 – ICM Bill Impacts (Total Bill) – Enersource RZ**

Rate Class	Unit	kWh	kW	ICM Rider Rate incl. HST	% Increase vs. Total Bill
Residential	kWh	750		$ 0.38	0.35%
General Service under 50 kW	kWh	2,000		$ 1.09	0.36%
General Service 50 to 499 kW	kW	110,000	230	$ 19.29	0.12%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 120.19	0.16%
Large Use	kW	3,000,000	5,000	$ 483.27	0.11%
Unmetered	kWh	300		$ 0.24	0.48%
Street Lighting	kW	33	0.1	$ 0.05	0.56%

Summary of Bill Impacts

A summary of bill impacts for the typical customer by rate class is presented in Tables 149 to 151 below. Attachment 38 provides a detailed summary of the bill impacts for each customer class for 2018.

Table 149 – Distribution Bill Impacts by Rate Class – Enersource RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ 0.41	1.67%
GS<50	kWh	2,000	$ 3.41	4.82%
GS 50-499 kW	kW	230	$ 138.58	11.86%
GS 500-4,999 kW	kW	2,250	$ 535.83	7.36%
Large User	kW	5,000	$1,368.85	4.68%
Street Lighting	kW	0.1	$ (2.79)	(101.95)%

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

Table 150 – 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	2018 vs. 2017	
			$	%
Residential	kWh	750	$1.13	4.21%
GS<50	kWh	2,000	$ 5.31	7.14%
GS 50-499 kW	kW	230	($16.31)	(1.38%)
GS 500-4,999 kW	kW	2,250	$ 530.74	8.42%
Large User	kW	5,000	$ 4,662.35	19.13%
Street Lighting	kW	0.1	($2.83)	(99.37)%

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

1 **Table 151 – Total Bill Impacts by Rate Class (before HST) – Enersource RZ**

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$1.20	1.18%
GS<50	kWh	2,000	$5.51	1.92%
GS 50-499 kW	kW	230	($8.61)	(0.06%)
GS 500-4,999 kW	kW	2,250	$ 604.09	0.92%
Large User	kW	5,000	$ 4,836.35	1.19%
Street Lighting	kW	0.1	($2.83)	(40.03%)

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

CONCLUSION

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